RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO OIL AND GAS LAWYERS

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This article identifies recent regulatory and legislative developments of interest to oil and gas lawyers. The authors survey a variety of subject areas, examining key decisions of courts, the National Energy Board, the Alberta Resources Conservation Board, the Alberta Surface Rights Board, and the Alberta Utilities Commission. In addition, the authors review a variety of key policy and legislative changes from the federal and provincial levels.

Cet article définit les récents développements réglementaires et législatifs qui intéressent les avocats travaillant dans le domaine pétrolier et gazier. Les auteurs passent en revue plusieurs domaines en examinant les grandes décisions des tribunaux, de l'Office national de l'énergie, du Alberta Resources Conservation Board, les droits de surfaces de l'Alberta et la Alberta Utilities Commission. En outre, les auteurs examinent un nombre de changements législatifs et de politique aux niveaux fédéral et provinciaux.

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I. INTRODUCTION

This article highlights many of the regulatory and legislative developments that have taken place over the past year that are of interest to oil and gas lawyers and others working within the industry. The format of the regulatory update article has been altered somewhat from previous years. While the article will still examine key decisions from the courts, the National Energy Board (NEB), the Alberta Energy Resources Conservation Board (ERCB), the Alberta Surface Rights Board (SRB), and the Alberta Utilities Commission (AUC), as well as key policy and legislative changes from the federal and provincial level, the presentation of these matters has been reorganized. Rather than chronicling and organizing the update by Court, Board, or Commission, summaries have been provided under broad topical categories and subcategories.

II. PIPELINES

A. JURISDICTION

1. NEB DECISION GH-5-2008: *TRANSCANADA PIPELINES LIMITED*

The TransCanada Alberta System (Alberta System) is an existing natural gas pipeline system, made up of over 23,500 kilometres of pipeline and associated compression and other facilities within the province of Alberta. The Alberta System is owned and operated by NOVA Gas Transmission Ltd. (NGTL), a wholly owned subsidiary of TransCanada Corporation (TransCanada) and, up until recently, was regulated under provincial legislation by the AUC.

On 17 June 2008, TransCanada filed an application with the NEB requesting: (1) a declaration that the Alberta System is properly within the jurisdiction of the NEB (the Jurisdictional Issue); and (2) the issuance of a Certificate of Public Convenience and Necessity (CPCN) in respect of the Alberta System under s. 52 of the *National Energy Board Act*[1] (the Facilities Process).[2]

An oral hearing was held between 18-28 November 2008 in Calgary, Alberta. On or about 26 February 2009, the NEB issued its decision on both the Jurisdictional Issue and the Facilities Process. In considering the Jurisdictional Issue, the NEB recognized that pursuant to the Canadian *Constitution Act, 1867*[3] "works and undertakings," such as energy pipelines that were wholly located within a province, were within the exclusive jurisdiction of the provincial legislature, whereas a pipeline that connects one province with another or that extended beyond the limits of a single province would properly fall within the exclusive jurisdiction of the federal Parliament.[4] In considering whether the Alberta System, which is wholly located within the Province of Alberta, could be federally regulated, the NEB relied on the test set out by the Supreme Court of Canada in *Westcoast*.[5] In *Westcoast,* the Supreme Court identified two ways in which a pipeline located solely within a province could fall within federal jurisdiction: first, if the pipeline is part of a federal "work or undertaking," and second, if the pipeline is integral to a federal "work or undertaking."[6]

TransCanada argued that the federal work or undertaking at issue in this case was the transportation of natural gas to markets within Canada and the United States. The NEB agreed and held that the Alberta System, together with TransCanada's other federally regulated pipelines, namely the Mainline and the Foothills System, were part of a single undertaking of TransCanada to transport natural gas to markets in Canada and the U.S. The NEB also found that the second test had been met and that the Alberta System was integral to the combined TransCanada undertaking. As a result, the NEB concluded that the Alberta

1 R.S.C. 1985, c. N-7 [*NEB Act*].
2 *TransCanada PipeLines Limited* (February 2009), Reasons for Decision GH-5-2008 (NEB) at viii, online: NEB <http://www.neb-one.gc.ca> [*TransCanada*].
3 (U.K.), 30 & 31 Vict., c. 3, reprinted in R.S.C. 1985, App. II, No. 5.
4 *TransCanada, supra* note 2 at 8.
5 *Westcoast Energy Inc. v. Canada (National Energy Board),* [1998] 1 S.C.R. 322 [*Westcoast*].
6 *Ibid.* at para. 45.

System was a pipeline within the meaning of the *NEB Act* and would fall under federal jurisdiction.[7]

In the Facilities Process, the NEB decided to issue a CPCN for the continued operation of the Alberta System. In reaching this decision, the NEB recognized that in order to provide for the efficient transfer of jurisdiction, the NEB would be required to accept decisions made previously by the Alberta regulators regarding the Alberta System, rather than re-deciding issues, which would potentially result in inconsistency and uncertainty.[8]

TransCanada did not specifically seek approval of its tolls and tariffs for the Alberta System at the hearing. Rather, TransCanada stated that it intended to file the operative tolls and tariffs with the NEB pursuant to the *NEB Act*. The NEB recognized that all parties wanted to reduce the uncertainty surrounding tolling issues for the Alberta System during the transition to NEB regulation. Toward that end, the Board allowed TransCanada to file its tariffs, including a schedule of tolls, that would become effective upon the coming into force of the CPCN.[9]

Federal regulation of the Alberta System is of great significance as TransCanada will now be permitted to apply to the NEB for an extension of the Alberta System across provincial boundaries (to British Columbia and the Northwest Territories), thereby providing producers in those regions with direct access to the Alberta pipeline network.

TransCanada's application to the NEB on the Jurisdictional Issue and the Facilities Process affected several unrelated applications regarding the Alberta System that were in front of the Alberta regulators at the time. Key among these hearings were the Alberta Energy Utilities Board (AEUB) Inquiry into Natural Gas Liquids Extraction in Alberta (the NGL Inquiry) and the TransCanada application before the AUC on the North Central Corridor (the NCC). In both the NGL Inquiry and the NCC Application, interested parties brought motions requesting that their respective hearings be found ultra vires the provincial regulators, as the Alberta System was now subject to federal jurisdiction. Details surrounding these jurisdictional challenges are discussed below.

2. AUC DECISIONS 2008-069 AND 2008-095: NORTH CENTRAL CORRIDOR APPROVAL AND JURISDICTION ISSUES

On 10 October 2008, NGTL received approval from the AUC to construct and operate pipeline and compression facilities, known collectively as the NCC.[10] The NCC will be an addition to the Alberta System and will transport gas directly from northwest to northeast Alberta, to meet growing demand due in large part to the development of the oil sands.

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7 *TransCanada*, *supra* note 2 at 9.
8 *Ibid.* at 17-18.
9 *Ibid.* at 37-38.
10 *Nova Gas Transmission Ltd. — Application for Permit and Licence* (10 October 2008), AUC Decision 2008-095, online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2008/2008-095%20and%20Errata.pdf>.

Various parties intervened in the NCC proceeding. One of the major issues raised was the potential for gas to be consumed within the northeast without first undergoing NGL extraction at the border straddle plants.

The issue of the AUC's jurisdiction over the Alberta System, in light of TransCanada's application to bring the Alberta System within federal jurisdiction, was raised at the outset of the hearing. Provident Energy Limited (Provident), an intervener with straddle plant interests, brought a motion requesting that the NCC application be found ultra vires the AUC as the proposed facilities were subject to federal jurisdiction (the Constitutional Question).[11]

The AUC denied Provident's motion, finding that s. 2(b) of the Alberta *Pipeline Act*[12] gave the AUC jurisdiction over "all" pipelines in Alberta with the exception of a pipeline "for which there is in force … a certificate … issued or made by the National Energy Board under the *National Energy Board Act*."[13]

As discussed above, a CPCN had yet to be issued by the NEB in respect of the Alberta System. The AUC reasoned that s. 2(b) of the *Pipeline Act* was enacted to ensure that no regulatory gap could exist during a transition of a major facility between provincial and federal jurisdiction.[14]

Provident subsequently sought leave to appeal the AUC's decision. The Canadian Association of Petroleum Producers (CAPP), Syncrude Canada Ltd. and Suncor Energy Marketing Inc., Imperial Oil Resources, and ExxonMobil Canada Energy each made applications for intervener status in the leave application brought by Provident.

In deciding the matter of intervener status in the leave to appeal application, the Alberta Court of Appeal acknowledged that there were no specific rules for granting leave to interveners before an appeal had been granted. While each of these three parties claimed to be directly affected by the appeal decision (had leave been granted) none of the parties were able to show exceptional circumstances in support of their proposed intervention. In particular, the Court was not satisfied that the applicants had special expertise or capacity to provide a unique perspective from that of the respondents in the leave application (that is, the AUC and NGTL). As a result, intervener status on Provident's leave to appeal application was denied.[15]

The Court further opted to deny Provident leave to appeal the AUC's decision regarding its jurisdiction over the NCC proceeding on the basis that the NEB would be deciding the same issues based upon more complete information and evidence.[16]

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11 *Nova Gas Transmission Ltd. — Reasons for Decision on Provident Motion and Constitutional Question* (4 August 2008), AUC Decision 2008-069, online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2008/2008-069%20and%20Errata.pdf> [*Provident Motion*].

12 R.S.A. 2000, c. P-15.

13 *Provident Motion, supra* note 11 at 14-15.

14 *Ibid.* at 19.

15 *Provident Energy Ltd. v. Alberta (Utilities Commission)*, 2008 ABCA 316, [2008] A.J. No. 1032 (QL).

16 *Provident Energy Ltd. v. Alberta (Utilities Commission)*, 2008 ABCA 362, [2008] A.J. No. 1172 (QL).

3. AEUB DECISION 2009-009: INQUIRY INTO NATURAL GAS LIQUIDS EXTRACTION MATTERS

On 4 June 2007, the AEUB initiated the NGL Inquiry. Participation was very broad, including natural gas producers, pipeline owners and their customers, industry associations, owners of NGL straddle plants and fractionation facilities, petrochemical producers, and various government actors, including the State of Alaska. The main focus of the inquiry was whether the existing convention for the extraction of NGLs on the Alberta System was equitable and in the best interests of industry and the Province of Alberta.

The issue of the AEUB's jurisdiction to continue the NGL Inquiry, in light of TransCanada's application to bring the Alberta System within federal jurisdiction, was raised on a motion and on a Notice of Question of Constitutional Law, by BP Canada, Inter Pipeline Fund, Provident, ATCO Midstream Ltd., and Spectra Energy Empress L.P. (the Applicants). The Applicants requested "a determination that issues respecting [NGTL's] tariffs, tolls, operations and practices, including any proposed change in contracting convention for [NGL] extraction rights in the common stream on the NGTL system, are *ultra vires* the Board, as the NGTL system is an interprovincial undertaking."[17]

After receiving argument from all participants, the AEUB issued a Decision on 15 August 2008 holding that it had jurisdiction to continue the inquiry and that it may issue recommendations relating to matters dealt with in the inquiry.[18] The AEUB did not address the question of whether the Alberta System was an interprovincial undertaking, but rather considered the case law regarding the permitted scope of a provincial inquiry that may impact a matter under federal regulation. The AEUB held that the "dominant purpose" of the Inquiry was the economic, orderly, and efficient development of Alberta's natural resources, which is a provincial head of power. To the extent any recommendation it made would impact matters under federal jurisdiction, such impact would, in the AEUB's view, be "incidental."[19]

An application for leave to appeal was brought by the Applicants to the Alberta Court of Appeal; however, at the time of writing, this application had been adjourned *sine die*.

B. FACILITIES

1. NEB DECISION OH-5-2007: *ENBRIDGE PIPELINES INC. LINE 4 EXTENSION PROJECT*[20]

Enbridge Pipelines Inc.'s (Enbridge) Line 4 Extension was approved by the NEB in April 2008. Prior to the extension, Line 4 transported crude oil from Hardisty, Alberta through Saskatchewan and Manitoba to the U.S. In its application, Enbridge proposed the

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17 *Inquiry into NGL Extraction Matters (Inquiry) — Ruling Regarding Motion and Notice of Question of Constitutional Law* (15 August 2008), EUB Application No. 1513726 at 1, online: ERCB <http://www.ercb.ca/docs/new/project/ngl/auc.NGLruling_20080815.pdf>.
18 *Ibid.* at 9-11.
19 *Ibid.* at 11.
20 *Enbridge Pipelines Inc. Line 4 Extension Project* (April 2008), Reasons for Decision OH-5-2007 (NEB), online: NEB <http://www.neb-one.gc.ca> [*Enbridge*].

construction and operation of three new pipe segments between the Edmonton Terminal and Hardisty pump station, and the connection of three existing inactive segments, to extend Line 4 upstream to Edmonton. Most of the pipeline utilized existing rights-of-way, but some new rights-of-way were required. Pipeline construction also required several watercourse crossings as well as changes to the existing facilities at the Edmonton Terminal, Kingman Station, and Strome Station.

In accordance with the *NEB Act*, upon issuance of a certificate of public necessity, a project proponent must submit its plans, profiles, and books of references (PPBoRs) for the pipeline.[21] Enbridge indicated that it would submit its PPBoRs for the three new segments, but took the view that for the three existing sections to be reactivated no further approvals should be required as the route already existed and PPBoRs were already approved for those segments. Enbridge also noted that no new lands were permanently required for the pump station modifications or the reactivations.

The NEB noted that PPBoRs were previously filed for the reactivated sections of pipe and station facilities and held that new PPBoRs were not required. The NEB was clear that Enbridge was still required to file PPBoRs for the three new sections of pipe in accordance with s. 33(1) of the *NEB Act*.[22]

2. NEB DECISION OH-1-2008: *TRANSCANADA KEYSTONE PIPELINE GP LTD.*[23]

Construction and operation of the Canadian portion of the TransCanada Keystone Pipeline GP Ltd. (Keystone) Keystone Pipeline was originally approved in NEB Decision OH-1-2007.[24] This portion of the project will extend 1,235 kilometres from Hardisty, Alberta to a location near Haskett, Manitoba at the border between Canada and the U.S. and will increase the capacity of the Keystone Pipeline by 156,000 barrels per day through additional pumping facilities. Keystone also indicated that it planned to extend the U.S. portion of the pipeline through construction of a 473 kilometre pipeline from the Nebraska/Kansas border to Cushing, Oklahoma (the Cushing Expansion Project).[25]

The NEB noted that in considering whether a project would be in the public interest, it takes into account the potential impacts on commercial third parties.[26] In its application, Keystone did not provide information on whether or not it notified commercial third parties of the application. After receiving direction from the Board, Keystone provided notification of its application to its shippers, interested parties, and parties to the initial proceeding for the Keystone Pipeline and published a Hearing Order in 24 newspapers.[27]

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21 *NEB Act*, *supra* note 1, s. 33.

22 *Enbridge*, *supra* note 20 at 22-23.

23 *TransCanada Keystone Pipeline GP Ltd.* (July 2008), Reasons for Decision OH-1-2008 (NEB), online: NEB <http://www.neb-one.gc.ca> [*Keystone Expansion*].

24 *TransCanada Keystone Pipeline GP Ltd.* (September 2007), Reasons for Decision OH-1-2007 (NEB), online: NEB <http://www.neb-one.gc.ca> [*Keystone*].

25 *Keystone Expansion*, *supra* note 23 at 1-2.

26 *Ibid.* at 6.

27 *Ibid.* at 9.

The Alberta Federation of Labour (AFL), an intervener in this matter, was of the view that little evidence had been provided on how the Cushing Expansion Project would impact the Canadian public interest. Specifically, the AFL wanted evidence of how the project would impact Canadian upgrading, refining, and secondary industries, as well as associated employment and investment. The AFL argued that the Cushing Expansion Project could result in the lost opportunity of thousands of permanent full-time jobs in Canada that could be created by upgrading bitumen in Canada prior to export. Keystone disagreed that the evidentiary record was insufficient and pointed to the information it provided in response to an information request by the AFL, which stated that two thirds of the Canadian bitumen forecast to be produced in 2015 was expected to be upgraded in Canada. The AFL submitted that the applicants should be required to study broader impacts. In response, Keystone maintained that the evidentiary record supported its view that it had properly scoped the socio-economic impact of the Cushing Expansion Project.

The NEB was satisfied that, as a result of the publication of the Hearing Order, potentially affected commercial third parties were properly notified of the project and had the opportunity to be heard. The NEB noted that for future applications, especially for those that may not be the subject of an oral hearing, it expected that Keystone would provide specific evidence relating to commercial third party notification, consistent with the requirements outlined in the NEB Filing Manual.[28]

In considering the merits of the application, the NEB was satisfied that there would be sufficient supply and markets to support the Keystone Cushing Expansion. The NEB determined that the evidentiary record was adequate to permit it to make a determination in the Canadian public interest. The NEB was not persuaded by AFL's argument that approval of the Cushing Expansion Project might mean a lost opportunity to generate thousands of permanent full-time jobs in Canada. Ultimately, the NEB approved the Cushing Expansion Project, concluding that it was economically feasible and likely to "provide a positive economic benefit for Canadians."[29]

3. AMENDMENTS TO THE *ONSHORE PIPELINE REGULATIONS, 1999* AND *NATIONAL ENERGY BOARD PROCESSING PLANT REGULATIONS* RELATED TO DECOMMISSIONING

Amendments to the *Onshore Pipeline Regulations, 1999*[30] and the *National Energy Board Processing Plant Regulations*[31] (collectively the Regulations) regarding decommissioning came into force 17 September 2008. The NEB developed Guidance Notes and an Exemption Order in parallel with the amendments to ensure clarity and consistency.[32] These amendments require a company to apply to the NEB when planning a permanent cessation of operation of facilities that does not result in a discontinuance of service.

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28 *Ibid.* at 9-10.
29 *Ibid.* at 11.
30 S.O.R./99-294.
31 S.O.R./2003-39.
32 National Energy Board, *Amendments to the* Onshore Pipeline Regulations, 1999 *(OPR) and* National Energy Board Processing Plant Regulations *(PPR) and Guidance Notes and Exemption Order — Decommissioning Provisions* (2 October 2008), online: NEB <http://www.neb.gc.ca/clf-nsi/rpblctn/ctsndrgltn/rrggnmgpnb/nshrppln/nshrpplnprcssngplntrgl tngdncnt-eng.pdf>.

The NEB stated that it intends to monitor compliance with the Regulations by reviewing company specifications and procedures and auditing their records and activities to determine their adequacy and effectiveness, and by performing inspections of onshore pipelines during their operating life.

C. ENVIRONMENTAL IMPACT ASSESSMENT

1. NEB DECISION OH-5-2007: *ENBRIDGE PIPELINES INC. LINE 4 EXTENSION PROJECT*

As discussed in Part II.B above, Enbridge's Line 4 Extension was approved by the NEB in April 2008.[33] In the Environmental Screening Report, the NEB concluded that, with implementation of the environmental protection procedures and mitigation measures outlined by Enbridge and the recommendations set out by the NEB, the Line 4 Extension Project was not likely to cause significant adverse environmental effects.[34]

Enbridge requested that the condition to file an Environmental Protection Plan (EPP) for the project be amended to allow Enbridge to submit two EPPs, each covering different aspects of the project. The NEB noted that it expects companies to submit all relevant plans and mitigation strategies in a timely manner as this information is critical in the determination of how mitigation measures will address potential impacts. The NEB observed that requests for surveys and plans were made in advance and that Enbridge should have known that it would need to provide these documents, as they had been required to do so for similar applications in the past. Nonetheless, Enbridge did not provide these materials until after the close of the evidentiary portion of the hearing. The NEB required Enbridge to obtain approval of the surveys and plans as a post-certificate condition and cautioned that companies should not expect post-certificate condition compliance matters to be dealt with more quickly than if they had been addressed in the hearing.[35]

The decision was issued in April 2008 with a planned construction start date of 5 May 2008. The NEB found that various conditions required Enbridge to submit certain documents prior to either the issuance of the decision or receipt of the requisite approval from the Governor in Council. For example, Condition 4 required the filing of the EPP for the station facilities at least 45 days prior to commencement of construction. The NEB noted that Enbridge appeared to have accepted the risks that tight project timelines create, but stated that the proposed timelines would not impact the time the NEB took to assess post-certificate matters. The NEB approved the splitting of the EPP.

In response to the NEB requirements, Enbridge agreed to develop and file a "commitments tracking table" listing all commitments and conditions, together with their status, and to provide monthly updates to the NEB until such time as final leave to open was granted.[36]

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[33] *Enbridge*, *supra* note 20.
[34] *Ibid.* at 15.
[35] *Ibid.* at 30, 35.
[36] *Ibid.* at 30-31.

2. NATIONAL ENERGY BOARD AND BRITISH COLUMBIA MEMORANDUM OF UNDERSTANDING

On 26 November 2008, the NEB signed a Memorandum of Understanding (MOU) with the British Columbia Environmental Assessment Office (the BCEAO) regarding the environmental assessment of projects subject to the *NEB Act*.[37] This MOU is intended to improve efficiency and avoid duplication of the provincial and federal processes. Under this MOU, the BCEAO accepted that any NEB and Canadian Environmental Assessment Agency (CEA Agency) review of a project in British Columbia that, based on the wording of the *Reviewable Projects Regulation*,[38] would trigger an assessment under the British Columbia *Environmental Assessment Act*,[39] would constitute an equivalent assessment under ss. 27 and 28 of the *BCEAA*. The overriding purpose of the MOU is to avoid potential jurisdictional disputes.

D. PUBLIC CONSULTATION AND STANDING

1. *OMERS ENERGY INC., RE*[40]

OMERS Energy Inc. (OMERS) applied to the ERCB for approval to construct and operate a pipeline to transport sweet natural gas from an existing well to a compressor station operated by Paramount Energy Operating Corp. (Paramount). Several landowners who had a direct interest in the property on which part of the proposed pipeline would be located intervened in opposition to the application, raising concerns regarding, among other things, public consultation, land value, future development, and routing. None of the landowner interveners disputed that the pipeline was needed. The ERCB ultimately denied the OMERS application.

In the lead-up to the hearing, the ERCB had encouraged the parties to engage in alternative dispute resolution (ADR).[41] One of the intervening landowners refused, saying that they did not believe that ADR was suitable for the situation. The ERCB examiners took the opportunity to comment in their report on the importance of ADR and their expectation that all parties engage each other in an attempt to address issues prior to the hearing. The examiners expressed the view that, generally, the landowners "did not make reasonable efforts to communicate their concerns and potential alternatives to OMERS despite being given numerous opportunities to do so"; their refusal to participate in ADR was only one such instance.[42]

The hearing was rescheduled several times. In the time between OMERS' initial consultation and the commencement of the hearing, a Paramount affiliate assumed operation

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37 *National Energy Board — British Columbia Agreement with respect to Environmental Assessment of Projects subject to the National Energy Board Act* (26 November 2008), online: Environmental Assessment Office <http://www.eao.gov.bc.ca/pub/2008/bc_mou_english.pdf>.

38 B.C. Reg. 370/2002.

39 S.B.C. 2002, c. 43 [*BCEAA*].

40 [2008] A.E.U.B.D. No. 92 (ERCB) [*OMERS Energy*].

41 The ERCB ordinarily uses the expression "appropriate dispute resolution" to describe what is more commonly called "alternative dispute resolution," and did so in this case.

42 *OMERS Energy*, *supra* note 40 at para. 8.

of all relevant facilities. OMERS considered alternative pipeline routes that would tie into an existing Paramount pipeline at different locations. Each of the alternative pipeline routes was discussed during the hearing.

The examiners commented on the factors that should be considered in choosing a pipeline route and how the interests of various parties should be taken into account:

> The examiners expect the applicant to consider issues relating to potentially concerned parties, such as the number of affected parties, land use, future development and future land use, the environment, and alternative routes and their effect on the potentially concerned parties. Further, the examiners expect the applicant to consider issues relating to the proposed pipeline route itself, such as the length, cost, surface disturbance, use of existing infrastructure, and technical and operating aspects. The examiners also expect the applicant to consider all of the potential pipeline routes and, if possible, select one that best addresses all concerns. The examiners also expect an applicant to carefully consider use of already existing infrastructure in order to reduce proliferation.[43]

In deciding that OMERS had not sufficiently investigated all available alternatives, the examiners noted that the proposed route would be the longest, most expensive, and affect the largest number of potentially concerned parties.[44] The examiners were also not satisfied that OMERS performed adequate consultation with the operator of the compressor station or potentially affected landowners. The examiners were not prepared to recommend approval of the proposed route because OMERS had not provided enough information to demonstrate that other feasible alternatives were adequately pursued.[45] This is the most noteworthy aspect of the decision.

2. *ATCO MIDSTREAM LTD. V. ENERGY RESOURCES CONSERVATION BOARD*[46]

Keyera Energy Ltd. (Keyera) applied to the ERCB to amend the licence for the Keyera Rimbey gas plant to permit modifications that would enable ethane extraction from the raw natural gas processed at the plant; this appeal stemmed from that application.[47] ATCO Midstream Ltd. (ATCO Midstream), a party with straddle plant interests, and NOVA Chemicals Corporation (NOVA Chem), an ethane purchaser, objected and sought standing in the Keyera application.

In its objection, ATCO Midstream claimed it would be directly and adversely affected by an approval of the Keyera application as it would result in a leaner common stream being available to the straddle plants.[48] ATCO Midstream argued that the application would increase its costs of operation and reduce its potential revenue stream. NOVA Chem objected on the basis that the Keyera project would reduce the productivity of certain ethane extraction facilities and increase the unit ethane cost to buyers.[49] NOVA Chem took the

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43 *Ibid.* at para. 47.
44 *Ibid.* at para. 48.
45 *Ibid.* at para. 62.
46 2008 ABCA 231, [2008] A.J. No. 640 (QL) [*ATCO*].
47 The application was made to the AEUB in September 2007. In January 2008, certain responsibilities of the AEUB (including those related to the Keyera application) devolved to the newly constituted ERCB.
48 *ATCO, supra* note 46 at para. 6.
49 *Ibid.* at para. 7.

position that it had a legitimate and material economic and commercial interest in, and would be directly and adversely affected by, any decision in the Keyera application.

The ERCB found that, although not expressly stated by ATCO Midstream or NOVA Chem, both parties were asserting a right to be economically protected from upstream ethane recovery.[50] The ERCB referred to the standing provision in s. 26(2) of the *Energy Resources Conservation Act*[51] and the test for standing as set out by the Alberta Court of Appeal in *Dene Tha'*.[52] The test in *Dene Tha'* involves two parts: the first is a legal test of whether the claim, right, or interest being asserted is one that is known to the law; the second is a factual test, which asks whether the Board has information to demonstrate that the application may directly and adversely affect the interests asserted.[53]

The ERCB held that the right asserted by ATCO Midstream and NOVA Chem, (that is, to be economically protected from upstream ethane recovery) was not a legally recognized right within the meaning of the *ERC Act*.[54] ATCO Midstream and NOVA Chem sought and were granted leave to appeal. The issues on appeal were: (1) did the ERCB deny ATCO Midstream and NOVA Chem standing and, if so, was the proper test applied; (2) did the ERCB err in failing to adjourn the Keyera application because of overlapping issues in the NGL Inquiry;[55] and, (3) did the ERCB fail to consider the public interest before issuing the licence.[56]

In a unanimous judgment, the Court of Appeal held that the ERCB had not erred in law or jurisdiction in declining to grant standing to ATCO Midstream and NOVA Chem; in light of that decision, the other two questions on appeal could not be addressed.[57]

The Court of Appeal found that the ERCB's characterization of the rights asserted by ATCO Midstream and NOVA Chem (that is, as "economic rights") was "at best" a determination of mixed fact and law that was not reviewable on appeal. Further, since ATCO Midstream and NOVA Chem had not cited any authority for the proposition that the economic interests they asserted were legally recognized under s. 26(2) of the *ERC Act* (and the Court was unaware of any such authority), no extricable error of law or jurisdiction had been established.[58]

The ERCB decides issues of standing on a case by case basis and it remains to be seen whether the Keyera decision will be interpreted and applied broadly. Still, the notion that

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50 *Ibid.* at para. 15.
51 R.S.A. 2000, c. E-10 [*ERC Act*].
52 *Dene Tha' First Nation v. Alberta (Energy and Utilities Board)*, 2005 ABCA 68, 363 A.R. 234, leave to appeal to S.C.C. refused, 30878 (18 August 2005) [*Dene Tha'*].
53 *Ibid.* at para. 10.
54 *ATCO*, *supra* note 46 at para. 15.
55 On 4 July 2007, the AEUB initiated an inquiry into matters related to NGL extraction from the common natural gas stream transported through pipeline transmission systems or processed by AEUB regulated facilities. The AEUB report was issued 4 February 2009: *Inquiry into Natural Gas Liquids (NGL) Extraction Matters* (4 February 2009), EUB Decision 2009-009, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2009/2009-009.pdf>; see also Part I.A, above.
56 *ATCO*, *supra* note 46 at para. 39.
57 *ATCO Midstream Ltd. v. Energy Resources Conservation Board*, 2009 ABCA 41, 446 A.R. 326 at para. 3.
58 *Ibid.* at paras. 10-11.

purely economic interests may be insufficient to warrant standing under s. 26(2) of the *ERC Act* may cause alarm in some quarters.

3. NEB HEARING ORDER GH-2-2008: SEMCAMS REDWILLOW PIPELINE PROJECT

SemCAMS Redwillow ULC (SemCAMS) filed its application with the NEB for the Redwillow Pipeline Project on 7 December 2007. The project proposed the construction of approximately 149.7 kilometres of new sour gas pipeline over mostly Crown lands, from a dehydration facility in British Columbia to existing Alberta regulated gathering and processing facilities near Grande Prairie. On 8 February 2008, the NEB issued a hearing notice indicating that the hearing for the Redwillow Pipeline Application would begin 3 June 2008.[59] SemCAMS submitted further evidence on 6 March 2008, with a caveat that it would be unable to file all of its detailed information about the potential impacts on traditional land use by potentially affected First Nations, Métis, and other Aboriginal groups until after the completion of the oral hearing.[60] Similarly, some of the information on the environmental impacts of the proposed route changes would not be available until after the completion of the scheduled oral hearing.

On 20 March 2008, the NEB issued an information request to SemCAMS and a letter suspending the hearing due to the purported paucity of information regarding, among other things, the potential impacts of the proposed project on traditional land use.[61] In a follow-up letter dated 10 April 2008, the NEB stated that full and complete information regarding field visits and other direct consultations must be presented to the Board at the hearing for their consideration. The NEB took the position that a project proponent is required to complete all of the Traditional Land Use (TLU) studies before a hearing can commence.[62]

The NEB hearing of the SemCAMS application ultimately began on 28 October 2008 in Dawson Creek, British Columbia. Several First Nations participated including the Horse Lake First Nation (HLFN), the Saulteau First Nations (SFN), and the Kelly Lake Cree First Nation — although the latter eventually withdrew its intervention. The NEB approved the Redwillow Pipeline Project on 26 March 2009, but attached 26 conditions to the approval.[63]

The decision provides some helpful guidance regarding the NEB's expectations of project proponents relating to their identification of, and response to, Aboriginal concerns:

> The Board requires applicants to take all reasonable steps to identify and contact Aboriginal people in the area of the proposed project prior to the filing of their applications. This is intended to ensure that potentially affected Aboriginal people have relevant information about the project and can be provided with an opportunity to discuss their concerns and issues with the applicant in the early planning stages of the project.

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59 *SemCAMS Redwillow ULC (SemCAMS) Redwillow Pipeline Project* (8 February 2008), Hearing Order GH-2-2008 (NEB), online: NEB <http://www.neb-one.gc.ca>.

60 *SemCAMS Redwillow ULC — Updates to the Redwillow Pipeline Project Application* (March 2008), NEB Order GH-2-2008 (NEB), online: NEB <http://www.neb-one.gc.ca>.

61 Letter from National Energy Board to SemCAMS Redwillow ULC (20 March 2008), online: NEB <http://www.neb-one.gc.ca>.

62 Letter from National Energy Board to SemCAMS Redwillow ULC (10 April 2008), online: NEB <http://www. neb-one.gc.ca>.

63 *SemCAMS Redwillow ULC Redwillow Pipeline Project* (March 2009), Reasons for Decision GH-2-2008 (NEB), online: NEB <http://www.neb-one.gc.ca> [*SemCAMS*].

> Through these early discussions, an applicant can often fully or partially address the concerns of the Aboriginal people or modify the project in response to such concerns. An applicant is required to file with its application evidence related to its discussions with potentially affected Aboriginal people as well as details of the issues or concerns raised, discussed and, where applicable, resolved. The Board will typically require further information and updates from an applicant. Aboriginal groups with unresolved concerns are encouraged to make their views known to the Board through some form of participation in the hearing. The Board takes all of the evidence about Aboriginal rights and interests into consideration as part of its assessment of the project impacts and determination of whether the project is in the public interest.
>
> Project proponents bear responsibility for ensuring that potentially affected Aboriginal people are made aware of the project and are given opportunities to discuss their concerns. Aboriginal peoples must be willing to take advantage of opportunities that proponents provide to them in order to learn about the project and express any concerns they might have.[64]

4. NEB DECISION GH-3-2008: *WESTCOAST ENERGY INC. CARRYING ON BUSINESS AS SPECTRA ENERGY TRANSMISSION*[65]

Westcoast Energy Inc., carrying on business as Spectra Energy Transmission (Westcoast), applied for a CPCN from the NEB for the construction and operation of the South Peace Pipeline. The proposed pipeline would extend the existing Fort St. John raw gas gathering system, allowing Westcoast to provide raw gas transmission and treatment services to producers in the South Peace Area. The project included approximately 92 kilometres of new pipe running from a receipt point in the Noel gas supply area to the Westcoast McMahon Plant.

Westcoast notified seven potentially affected Aboriginal communities of the project in July 2007 and sent information packages to those groups in November and December of that year. Consultation began at an early stage and continued throughout the process with an additional three Aboriginal communities being added. An Archaeological Impact Assessment and a TLU assessment were undertaken with the participation of seven Aboriginal communities. The NEB noted that "[i]n addition to identifying traditional use sites and recommending mitigation, the TLU assessment process provided a forum for addressing the potential concerns of Aboriginal communities."[66]

Many concerns were addressed throughout the process. The NEB noted as an example that, as a result of the TLU assessment process, the concerns of the Kelly Lake Métis Settlement Society regarding the disturbance of potential burial sites were addressed by ensuring no such sites were located within the project footprint.[67]

Despite the fact that most concerns of the Aboriginal communities were addressed through consultation, and no Aboriginal community participated as an intervener in the hearing, the NEB took the opportunity to comment regarding its expectations for Aboriginal consultation.

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64 *Ibid.* at 35-36.

65 *Westcoast Energy Inc. Carrying on Business as Spectra Energy Transmission* (November 2008), Reasons for Decision GH-3-2008 (NEB), online: NEB <http://www.neb-one.gc.ca> [*Westcoast*, NEB].

66 *Ibid.* at 14.

67 *Ibid.*

The comments mirrored those set out in the decision respecting the Redwillow Pipeline Project, discussed above.[68]

The NEB reviewed the steps that Westcoast had taken as well as the commitments that it had made. The conclusion was that the impacts of the proposed pipeline on Aboriginal interests were likely to be minimal and that such impacts could be appropriately mitigated.[69]

E. LAND MATTERS

1. *ALLIANCE PIPELINE LTD. V. BALISKY*[70]

Alliance Pipeline Ltd. (Alliance) appealed a decision of the Pipeline Arbitration Committee (the PAC) appointed under the *NEB Act* to rehear the Balisky *et al.* group of landowners' compensation claims for land acquisition. The basis for appeal was founded on the PAC's failure to adhere to the Federal Court's guidance in *Bue*.[71] More specifically, Alliance submitted that the PAC failed to properly consider which of the compensation factors under s. 97(1) of the *NEB Act* were relevant to the specific determination of compensation payable for the acquisition of lands, and the relevance of the $500/acre entry fee payable in Alberta by provincially regulated pipelines. Alliance also argued that the PAC erred by applying a methodology that was entirely without precedent for three landowners where the PAC did not find a pattern of dealings. The landowners filed a cross-appeal challenging the PAC's award of compensation in the form of a lump sum, which could be elected by a landowner to be taken in instalments. The landowners submitted that their ability to elect to take payments either as a lump sum or by annual or periodic payments under s. 98(1) of the *NEB Act* meant they could request compensation in the form of a land rental.

With respect to the $500/acre entry fee prescribed under the *Surface Rights Act*,[72] but not the *NEB Act*, O'Reilly J. upheld the PAC's inclusion of the entry fee as part of the pattern of dealings in Alberta as well as British Columbia. At the same time, he noted that not all arbitration committees would agree that the $500/acre entry fee was appropriate, as evidenced by the *Bue* awards, which excluded it in the context of the very same pipeline project.[73]

In its decision, PAC had set a methodology for determining the compensation payable for the acquisition of rights-of-way across lands traversed by the Alliance Pipeline near Edmonton, Alberta and Fort St. John, British Columbia for which no pattern of dealings was discernible. This methodology involved a multiplication of the per-acre fee simple market value of the lands by a factor (that is, 1.58) based on the relative magnitudes of the $950/acre pattern of dealings and a deemed representative per-acre fee simple of $600/acre in the Peace River area. The PAC then added the $500/acre Alberta entry fee equivalent to the amount determined in accordance with that methodology. Justice O'Reilly rejected the PAC's

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68 See *supra* note 63 and accompanying text.
69 *Westcoast*, NEB, *supra* note 65 at 17.
70 2008 FC 1087, 336 F.T.R. 60 [*Alliance Pipeline*].
71 *Bue v. Alliance Pipeline Ltd.*, 2006 FC 713, 293 F.T.R. 1 [*Bue*].
72 R.S.A. 2000, c. S-24.
73 *Alliance Pipeline*, *supra* note 70 at para. 31.

methodology having found that there was no legal foundation for it, notwithstanding that there may be some arithmetic logic to the approach.[74] Having failed to find a pattern of dealings, O'Reilly J. held that the law required the PAC to determine the compensation payable by reference to the factors in the *NEB Act*, and not by extrapolating the pattern of dealings from one area to calculate the compensation payable in another.

With respect to the pattern of dealings, the PAC justified its constituting a significant premium over the market value of the subject lands (which premium the PAC held included the Alberta entry fee) on the basis that it must consider factors other than land value and the adverse effect of the taking on the remaining lands of the owner. Such other factors included loss of use and nuisance, noise, and inconvenience. Justice O'Reilly held that the PAC was correct in its considering the above factors in determination of compensation for land acquisition.[75] This finding, however, is incongruent with the decision by Campbell J. in *Bue*, which concluded that not all of the factors in s. 97 of the *NEB Act*, especially those concerning damages arising from the operations of a pipeline company, were applicable to the issue of compensation for land acquisition.[76]

Justice O'Reilly set aside the PAC's compensation award for three of the landowners (those for which there was insufficient evidence of a pattern of dealings) and referred the matter back to the PAC for redetermination. He also denied the landowners' cross-appeal, confirming Campbell J.'s decision in *Bue* that the election provided to landowners under s. 98(1) of the *NEB Act* did not permit for the awarding of a form of land rent.

2. *CANADIAN ALLIANCE OF PIPELINE LANDOWNERS' ASSN. V. ENBRIDGE PIPELINES INC.*[77]

On 31 May 2000, the appellants instituted the action giving rise to this appeal under Ontario's *Class Proceedings Act, 1992*.[78] The appellants made claims on their own behalf and on behalf of other agricultural landowners in Canada who have lands subject to the respondents' federally regulated pipeline easements. The appellants alleged, among other things, that they suffered loss of income, increased costs, and diminished property values from having to modify or restrict existing agricultural operations to comply with the new land use restrictions and requirements under s. 112 of the *NEB Act* and the *National Energy Board Pipeline Crossing Regulations*.[79]

The respondents, Enbridge and TransCanada Pipelines Limited (TCPL), own and operate interprovincial pipelines for the transmission of petroleum products and natural gas. The appellants, 488796 Ontario Limited (488796) and Ronald Kerr (Kerr) own and operate farms on which the respondents' easements are located. By agreement dated 18 March 1957, 488796's predecessor in title granted Interprovincial Pipe Line Company, now Enbridge, an easement over a 60-foot wide strip of land. By agreements dated 3 and 11 July 1967, Kerr's

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74 *Ibid.* at para. 26.
75 *Ibid.* at para. 22.
76 *Bue, supra* note 71 at paras. 44-46.
77 2008 ONCA 227, 237 O.A.C. 200 [*Canadian Alliance*].
78 S.O. 1992, c. 6 [*CPA*].
79 *National Energy Board Pipeline Crossing Regulations, Part I*, S.O.R./88-528; *National Energy Board Pipeline Crossing Regulations, Part II*, S.O.R./88-529 [*Pipeline Crossing Regulations*].

predecessor in title granted TCPL a 75-foot wide easement over their lands. Both 488796 and Kerr are members of associations that belong to the Canadian Alliance of Pipeline Landowners' Associations (CAPLA),[80] a third appellant who represents the interests of agricultural landowners with respect to energy pipelines.

It is worth noting that prior to the action at issue in this appeal, CAPLA, acting on behalf of individual landowners, including 488796 and Kerr, had requested arbitration under s. 90(1) of the *NEB Act* from the Minister of Natural Resources (the Minister) for determination of their claims for compensation under s. 75 of the *NEB Act* for the loss of interest in, and use and enjoyment of, the land sustained as a result of the provisions of s. 112. The Minister denied CAPLA's request on the basis that the claims were not arbitrable under the *NEB Act* as the damages sought "were not a direct result of an activity of a pipeline company, nor were the damages claimed the result of the exercise by Enbridge or TCPL of powers conferred upon them by the [*NEB Act*]."[81] The appellants brought the action underlying this appeal rather than challenging the Minister's decision by applying for judicial review.

The appellants brought a motion seeking an order that their action satisfied the certification requirements of s. 5(1) of the *CPA*. The appellants based their claim on three causes of action: (1) a statutory cause of action for compensation found in s. 75 of the *NEB Act*; (2) contractual rights to compensation under their easement agreements; and (3) actions in contract for breaches of covenants in their easement agreements. The respondents moved for summary judgment to dismiss the appellants' claims on the basis that the evidence did not disclose a cause of action.

The motion judge granted the respondents' motion for summary judgment on the basis that the appellant's action did not raise any genuine issues for trial. The motions judge came to this decision based on four findings.

> First, s. 75 of the [*NEB Act*] does not create a statutory cause of action for damages. It only entitles a landowner to seek compensation through the negotiation and arbitration scheme set out in the *Act*. Second, the Minister's decision refusing to refer the appellants' claims to arbitration operated as an *estoppel* to the appellants' claims under s. 75 of the *Act* in the within action. Third, [488796] and Kerr are not entitled to compensation under the compensation provisions in their easement agreements. Fourth, any breaches by the respondents of covenants in the easement agreements were mandated by a change in the law and, therefore, the doctrine of frustration relieved the respondents of liability.[82]

The motion judge also dismissed the motion for certification under the *CPA*.

There were three issues in the appeal:

(1) Does s. 75 of the *NEB Act* create a statutory cause of action?

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[80] CAPLA has since changed its name to the Canadian Association of Energy and Pipeline Landowner Associations.
[81] *Canadian Alliance*, *supra* note 77 at para. 23 [footnote omitted].
[82] *Ibid.* at para. 27.

> (2) Do the easement agreements require the respondents to compensate the appellants for damages arising from the imposition of land use restrictions pursuant to s. 112 of the [*NEB Act*] and the *Pipeline Crossing Regulations*?
>
> (3) Do the land use restrictions referred to above breach any of the covenants made by the respondents under the easement agreements?[83]

O'Connor A.C.J.O. agreed with the motion judge's finding that s. 75 of the *NEB Act* did not create a statutory cause of action. He also agreed with the motion judge that s. 75 did not create a civil cause of action by considering the plain meaning of the language used in the *NEB Act* and indicators of Parliament's intent.[84]

In considering whether the motions judge erred in holding that the damages in the statement of claim were not compensable under the easement agreements, the Court of Appeal considered the compensation provisions in the two easement agreements separately.

The compensation provision (Third clause) in favour of 488796 required Enbridge to pay compensation for "for damage done to any buildings, crops, tile drains, fences, timber, culverts, bridges, lanes and livestock on the said land by reason of the exercise of the rights hereinbefore granted."[85]

Justice O'Connor found that, according to the language in the Third clause, Enbridge did not have an unlimited obligation to pay compensation for all losses resulting from Enbridge's operation of a pipeline on 488796's lands. Justice O'Connor was satisfied that the plain and ordinary meaning of the words "damage done to" in the context of the Third clause referred to physical damage to the listed items and did not extend to economic losses incurred as a result of the presence of the pipeline on 488796's lands.[86]

In its statement of claim, 488796 had not alleged any physical damages to the property items listed in the Third clause. 488796 only referred to "'crop and related productivity loss[es]' (i.e. economic losses)"[87] caused by the imposition of the land use restrictions. Justice O'Connor found that these types of losses did not fall within the compensation requirements under the Third clause.

Kerr's claim for compensation under the compensation provision of the agreement with TCPL also failed. In that agreement, the requirement to pay compensation was explicitly limited to "physical damages resulting from the exercise of any of the rights herein granted."[88] Kerr did not allege physical damage to his property, but instead alleged damages flowing from the Government's imposition of the land use restrictions. For the reasons given above, O'Connor J. found that the compensation provision in Kerr's easement agreement did not apply.

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83 *Ibid.* at para. 29.
84 *Ibid.* at para. 31.
85 *Ibid.* at para. 48 [emphasis added].
86 *Ibid.* at para. 49
87 *Ibid.* at para. 51.
88 *Ibid.* at para. 56.

The appellants also claimed that the respondents had breached covenants, other than the compensation provisions in the easement agreements, by "(1) failing to confine their operations to the lands subject to the easements; and (2) interfering with the appellants' rights to conduct their agricultural operations on or outside the easements."[89]

Justice O'Connor agreed with decision of the motions judge that there were no express provisions in either agreement whereby the respondents agreed to confine their activities to the easement lands nor were there express provisions that the respondents would not interfere with the appellants' operations. As a result, the respondents had not breached any covenants.

The Ontario Court of Appeal dismissed the appeal awarding costs of the appeal to the respondents.

3. *ENBRIDGE PIPELINES (ATHABASCA) V. KARPETZ*[90]

This matter involved 14 properties transected by the Enbridge Waupisoo Pipeline Project during the summer of 2007. The Operator, Enbridge Pipelines (Athabasca) Inc. (Enbridge Athabasca), and the respondents were unable to negotiate easement agreements. Right of entry orders were issued by the SRB and a hearing was held to determine compensation in accordance with s. 25 of the *Surface Rights Act*. The SRB had to determine the appropriate compensation payable for the right of entry order, the appropriate compensation structure, and to whom compensation was payable.

Enbridge Athabasca submitted that a "pattern of dealings of 1,900.00 per acre for right-of-way and 950.00 per acre for temporary workspace existed at the time the Right of Entry Orders were granted."[91] Nearly 200 right-of-way agreements negotiated between operators and landowners were presented to establish the pattern of dealings. Enbridge Athabasca took the position that the respondents would only suffer a loss of use of the area covered by the right of entry order for a temporary period until the right-of-way was restored to agricultural use. On the issue of whether to grant annual payments for pipelines, Enbridge Athabasca argued that the issue had been decided by the SRB and the Alberta Court of Queen's Bench on a number of occasions and in every case annual payments were determined to be inappropriate as the nature of pipeline takings did not result in an ongoing loss of use of the surface lands for farming operations. The annual payment program instituted by NGTL in Alberta between 1981 and 2002, which provided annual compensation for pipeline rights-of-way and upon which the Respondents sought to rely, was argued by Enbridge Athabasca not to constitute a precedent for a number of reasons including that the annual payments made under that program were not made in recognition of any ongoing loss of use or adverse effect.

The respondents requested an award comprised of an initial payment of $1,900/acre based on the pattern of dealings asserted by Enbridge Athabasca, but supplemented by an additional $100/acre of annual compensation. The respondents argued since the right-of-way taking was

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89 *Ibid.* at para. 58.

90 (14 October 2008), SRB Decision 2008/0362, online: SRB <http://www.surfacerights.gov.ab.ca/orders decisions/default.aspx>.

91 *Ibid.* at 8.

for an indefinite period of time in which the landowner must coexist with the company and in which there is uncertainty as to long-term effects, annual compensation reviewable at regular intervals was the only fair method of compensation. The respondents also submitted that compensation should not be based only on land value and that "loss of use" should be considered in its widest sense.[92]

The SRB fixed first year compensation at $700/acre and annual compensation at $100/acre. The SRB noted that its role was to consider the evidence and to determine fair and reasonable compensation that "comes as close as possible to making the Landowners whole."[93] On this basis, the SRB determined that it was only reasonable to award annual compensation since only an annual award provided compensation that was contemporaneous with the events and factors attracting the compensation. The SRB outlined its reasons for being persuaded that the respondents would experience ongoing and/or recurring compensable losses, the reasons it did not accept Enbridge Athabasca's or the respondents' requested compensation, and the reasons for determining the award of compensation.

The SRB was persuaded that the *Surface Rights Act* should be read in a broad and purposive manner. Based on the evidence and the arguments presented, the SRB rejected the proposition that there would be "'zero' ongoing and/or recurring losses."[94] The SRB gave weight to several considerations, which it was persuaded constituted ongoing and/or recurring loss of use, adverse effect, nuisance, and inconvenience, which should be compensated annually. First, the SRB concluded that the respondents would have to alter and adapt their agronomic practices due to the pipeline. Second, SRB considered that the respondents could never forget about the presence of the pipeline lest a catastrophic result occur. Finally, the SRB recognized that the respondents' Land Titles Certificates would contain caveats registering Enbridge Athabasca's interest in the respondents' lands.

The SRB noted that it would have appreciated more argument on: the magnitude of the ongoing and/or recurring losses; the degree to which nuisance, inconvenience, or loss was factored into Enbridge Athabasca's final compensation offer for the acquisition of rights-of-way; what the best manner to be compensated for ongoing and recurring loss ought to be in the circumstances; the need for final resolution; and any methods to reconcile the parties' positions and whether annual compensation is a practical solution.[95]

The SRB was persuaded that there were cogent reasons for not recognizing the claimed pattern of dealings. The SRB found that the comparables presented by Enbridge Athabasca (none of which provided for annual compensation) were outdated as they were between one and five years old and otherwise of little evidentiary value since they did not have identical or similar terms. Nevertheless, the SRB reasoned that since the respondents' lands had a fee simple value ranging from $650 to $715/acre, Enbridge Athabasca's proposed lump sum compensation, based on an alleged pattern of dealings amount of $1950/acre, must account for something more than mere land value. While the SRB accepted that there were ongoing and recurring losses that warranted annual compensation, it also was mindful that the present

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92 *Ibid.* at 11.
93 *Ibid.* at 19.
94 *Ibid.* at 23.
95 *Ibid.*

value of its compensation award should not amount to double compensation.[96] Accordingly, it concluded that the respondents' compensation proposal, which was comprised of an initial amount of $1,950/acre and annual payments of $100/acre, was excessive.

The SRB noted that in the absence of any quantification of the ongoing or recurring loss of use, adverse effect, noise, nuisance, and inconvenience suffered by the respondents, an arbitrary annual award of $100/acre was reasonable, provided that the initial award was $700/acre rather than the $1,950/acre requested by the respondents. In effect, the SRB structured its award to achieve a present value of approximately $1,950/acre. As the respondents had already been paid an upfront amount exceeding $700/acre by Enbridge Athabasca, the SRB determined that it would be unfair to order immediate repayment. Repayment of any excess by the respondents was deferred until 2011.[97]

This decision has been appealed by Enbridge Athabasca and is slated to be heard by the Alberta Court of Queen's Bench in December 2009.

4. LAND MATTERS CONSULTATION INITIATIVE

The Land Matters Consultation Initiative (LMCI) was announced by the NEB in October 2007 as part of its review of key issues related to land matters. At the time, the NEB described the LMCI as a forum for all interested parties and the NEB to "dialogue and generate options to support the long-term responsible development of the energy sector, while respecting the rights of those affected."[98]

The NEB ultimately elected to consider the LMCI topics in four parts or "streams": (1) company interactions with landowners; (2) improving the accessibility of NEB processes; (3) pipeline abandonment — financial issues; and (4) pipeline abandonment — physical issues.[99]

As part of the LMCI, the NEB held more than 40 workshops and meetings in 25 different communities across Canada. It also received written submissions from more than a dozen individuals and groups.

Only the third stream, concerning pipeline abandonment — financial issues, involved a public hearing, which took place in Calgary in mid-January 2009. Issues considered during the hearing included whether the Board should require pipeline companies that it regulates to set aside funds to cover the costs of future abandonment and, if so, when should collection of funds commence?

The hearing proceeded over six days of evidence and argument and saw active participation by most of the large, NEB regulated oil and gas pipelines, as well as some

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96 *Ibid.* at 25.
97 *Ibid.* at 29.
98 "Land Matters Consultation Initiative," online: NEB <http://www.neb.gc.ca/clf-nsi/rthnb/nvlvngthpblc/lndmttrs/lndmttrs-eng.htm>.
99 *Ibid.*

smaller ones. CAPLA and CAPP were the other principal participants. The NEB issued a decision on this matter in May 2009.[100]

The decision established the goal that all pipeline companies that are regulated by the NEB will begin, by 2014, to collect and set aside funds to cover the costs of abandoning their facilities. The decision also included findings that NEB regulated pipeline companies are responsible for the full costs of abandoning their facilities and that it would not be either reasonable or prudent to assume physical removal of all large pipes as a basis for estimating abandonment costs. Pipeline companies are required to file preliminary estimates of their abandonment costs with the NEB on or before 31 May 2011 and decisions by the NEB regarding those preliminary estimates would be issued before 31 May 2012. Larger pipelines (to which the NEB refers as "Group 1") will be required to file their proposals for collection and setting aside of funds before 30 November 2012. The NEB will issue decisions regarding those proposals by 31 May 2014. Collection will be expected to begin thereafter. Importantly, the decision made it clear that pipeline companies may propose for NEB approval either deferral of, or exemption from, their collection obligations.

F. EMERGENCY RESPONSE PLANNING

1. *DIRECTIVE 071: EMERGENCY PREPAREDNESS AND RESPONSE REQUIREMENTS FOR THE PETROLEUM INDUSTRY*

In 2008, the ERCB finalized its efforts to update *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*.[101] Effective 8 April 2008, all new wells, pipelines, and facilities must comply with the new Directive, which revises the 2005 version.

One of the key amendments to *Directive 071* is that all Emergency Response Plans (ERPs) must now include the new Assessment Matrix developed by the ERCB for classifying incidents. The Assessment Matrix was developed so that incidents can be classified and reported to other industry members, emergency response organizations, health authorities, and the government in a consistent manner.[102]

Another key change is that the size of all Emergency Planning Zones (EPZ) for sour well site-specific drilling ERPs and sour operation ERPs must be calculated using the ERCBH2S software modelling program.[103] Under the old Directive, corporations could apply to the ERCB to have a decreased EPZ; under the revised Directive this is no longer an option. Furthermore, licensees are now required to calculate EPZs for high vapour pressure (HVP) pipelines and cavern storage facilities.

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[100] *Land Matters Consultation Initiative Stream 3: Financial Issues related to Pipeline Abandonment* (May 2009), Reasons for Decision RH-2-2008 (NEB), online: NEB <http://www.neb-one.gc.ca>.

[101] Energy Resources Conservation Board, *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry* (Calgary: Energy Resources Conservation Board, 2008) [*Directive 071*].

[102] *Ibid.* at 10.

[103] *Ibid.* at 12.

With respect to public education, licensees are now required to notify, and in some cases consult, the public, landowners, and other entities in an EPZ before submitting an application for an ERP. Whether notification and consultation, or only notification, is required depends on the potential directly and adversely affected party.[104] Furthermore, licensees are no longer required to update their ERPs annually, but rather are required to establish an on-line update program that ensures their documentation reflects the most up-to-date company information, mapping information, resident contact information, and response staff information.

There are many other specific changes in the revised *Directive 071* and industry participants would be well advised to review the revised Directive in detail to evaluate how it will effect their operations.

G. TOLLS AND TARIFFS

1. NEB DECISION RH-1-2008: TRANS QUÉBEC & MARITIMES PIPELINES INC. COST OF CAPITAL HEARING[105]

The Trans Quebec and Maritimes (TQM) is a 572 kilometre pipeline system connected to the TransCanada Canadian Mainline that transports natural gas from Sainte-Lazarae to a point near Quebec City and connects with the Portland Natural Gas Transmission system at the Quebec/New Hampshire border.

Until this application TQM, like other pipelines under NEB jurisdiction, calculated its cost of capital based on the NEB's decision in the Multi-Pipeline Cost of Capital Proceeding.[106] In that decision, the Board approved a rate of return on common equity (ROE) for a low-risk, high-grade bench-mark pipeline based primarily on the equity risk premium test. ROE for the bench-mark pipeline was set at 12.25 percent for the 1995 test year and the Board adopted a formula for adjusting the ROE annually (RH-2-94 Formula).

> The RH-2-94 Formula directly links the ROE to a forecast of a long-term Government of Canada bond yield and adjusts the ROE for 75 per cent of the change in the forecasted yield. The forecast of a long-term Government of Canada bond yield is determined by averaging the 3-month-out and 12-month-out forecasts of 10-year Government of Canada bonds as published by *Consensus Forecasts* in November of each year. To this average is added the average spread between 10-year and 30-year Government of Canada bond yields as published daily in *The Financial Post* throughout the month of October of that year.[107]

At the end of 2007, TQM applied, pursuant to s. 21(1) of the *NEB Act*, for a review and variance of the methodology that the NEB used to calculate TQM's cost of capital. TQM also applied for an order approving an overall fair return on capital for 2007 and 2008.

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104 *Ibid.* 16-17.

105 *Trans Québec & Maritimes Pipelines Inc.* (March 2009), Reasons for Decision RH-1-2008 (NEB), online: NEB <http://www.neb-one.gc.ca> [*Trans Québec*].

106 *TransCanada Pipelines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd., Trans Québec & Maritimes Pipelines Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd. and Trans-Northern Pipeline Inc.* (March 1995), Reasons for Decision RH-2-94 (NEB), online: NEB <http://www.neb-one.gc.ca>.

107 *Trans Québec*, *supra* note 105 at 9 [footnotes added].

The Board agreed with TQM's position on the issue of what constitutes a fair return and held that the legal framework for determining a fair return was that set out in RH-2-2004.[108] More specifically, the Board stated that the "Fair Return Standard" required that a fair or reasonable overall return on capital for a regulated company should:

- be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
- enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement).[109]

The Board recognized that in RH-2-2004, it had used the word "standard" for each of the elements of the Fair Return Standard. In a footnote, the Board explained that it had changed the word "standard" to "requirement" in order to "clarify that there are three requirements which should be met under the Fair Return Standard."[110]

The Board recognized that often the largest, and therefore most important, portion of the revenue requirement is the overall return on equity. In considering the balance between the investor and customer interests, the Board found that "[w]hile customers and consumers have an interest in ensuring that the cost of equity is not overstated, in the Board's view, this is factored in by having intervenors test and challenge the position the company has put forward."[111] The Board then considered the findings of the Federal Court of Appeal in *Transcanada v. NEB*[112] that the "overall return on equity must be determined solely on the basis of the company's cost of equity capital, and that the impact of any resulting toll increase is an irrelevant consideration in that determination."[113]

The Board then considered whether it should use its discretion granted under s. 21 of the *NEB Act* to review the RH-2-94 Formula. The Board commented that there was no automatic right of review of a Board decision; instead, a review entails a two-step process. First, the Board must determine that a doubt had been raised regarding the correctness of the impugned decision or order. Second, if that test is met, the review would be considered on its merits.[114]

In arguing that the RH-2-94 Formula should be reviewed for TQM for 2007 and 2008, TQM submitted that there had been significant changes in business circumstances, financial markets, and general economic conditions since the RH-2-94 proceedings. These changes

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108 *TransCanada PipeLines Limited* (April 2005), Reasons for Decision RH-2-2004 Phase II (NEB), online: NEB <http://www.neb-one.gc.ca>.
109 *Trans Québec, supra* note 105 at 6-7.
110 *Ibid.* at 7, n. 14.
111 *Ibid.* at 6.
112 *Transcanada Pipelines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, 319 N.R. 171 [*Transcanada v. NEB*] (reviewing *TransCanada PipeLines Limited* (June 2002), Reasons for Decision RH-4-2001 (NEB), online: NEB <http://www.neb-one.gc.ca>).
113 *Trans Québec, supra* note 105 at 6.
114 *Ibid.* at 8.

had impacted the market environment in which gas pipelines in North America operate and, more generally, the global financial systems and markets.

CAPP opposed the application to review the RH-2-94 Formula on the basis that the ROE used in the RH-2-94 Formula was in fact generous and that the use of the RH-2-94 Formula provided predictability and stability and allowed for the streamlining of regulatory proceedings. The Industrial Gas Usage Association (IGUA) and the Province of Ontario also opposed a review of the RH-2-94 Formula.

The Board agreed with TQM that there had been significant changes in the markets since 1994. More specifically, the Board noted that the "Canadian financial markets have experienced greater globalization, the decline in the ratio of government debt to GDP has put downward pressure on Government of Canada bond yields, and the Canada/US exchange rate has appreciated and subsequently fallen."[115] The Board recognized that the RH-2-94 Formula relied on a single variable: the long-term Canadian bond yield. Changes that could potentially affect TQM's cost of capital may not be captured by this indicia and consequently, may not be accounted for by the RH-2-94 Formula. As a result, the Board decided to "grant the variance from the RH-2-94 Decision to TQM for 2007 and 2008 as it relates to its cost of capital."[116]

In deciding the approach to be used to determine TQM's return on capital for 2007 and 2008, the Board considered the approaches that had been presented. TQM argued that the After Tax Weighted Average Cost of Capital (ATWACC) methodology was more appropriate as it was an aggregate approach to the estimated cost of capital. The Board adopted the ATWACC approach as it was, in the Board's view, "more aligned with the way that capital budgeting decision making takes place in the business world."[117] The NEB also stated that "the ATWACC approach better utilizes financial market information."[118]

In applying the ATWACC methodology to evaluate TQM's cost of capital, the NEB recognized certain risks that TQM faced including: supplier risks regarding natural gas; market risks due to the uncertainty surrounding Quebec's industrial and power generation sector's demand for natural gas; and business risks due to increased competition.

The Board, after having considered the evidence and factors influencing TQM's total return, concluded that an ATWACC of 6.4 percent on rate base was a fair total return for TQM for 2007 and 2008.[119] It was the Board's view that a total return of 6.4 percent would be in line with North American pipelines of comparable risk and therefore would ensure that TQM's total return on capital met the comparable investment requirement. Furthermore, the Board concluded that a total return of 6.4 percent would help TQM maintain its credit rating on a stand-alone basis. As a result, TQM could continue to "maintain its financial integrity and its ability to attract capital on reasonable terms and conditions."[120]

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115 *Ibid.* at 16.
116 *Ibid.* at 17.
117 *Ibid.* at 18.
118 *Ibid.*
119 *Ibid.* at 80.
120 *Ibid.*

Though the Board made it clear that its decision in this case related only to TQM for 2007 and 2008, it considered many factors that were not unique to TQM, such as the significant changes in both the global and Canadian financial markets since 1994 and the changes in gas supply and pipeline competition. A logical question that arises is, if the RH-2-94 Formula is no longer applicable to TQM for 2007 and 2008 as it does not reflect the current gas pipeline business in North America, current financial markets, and general economic conditions, can the RH-2-94 Formula be considered appropriate for other pipelines that are influenced by the same factors?

On 23 March 2009, the NEB issued a letter to various stakeholders requesting submissions on whether the Board should review the RH-2-94 decision.[121] The letter requested that interested persons comment on whether they believe the RH-2-94 decision should be reviewed, the process that should be used, and the issues to be considered if a review were held. Submissions on this point were to be filed by 25 May 2009.

2. EUB DECISION 2004-052: 2009 GENERIC COST OF CAPITAL PROCEEDING[122]

In this decision, the AEUB adopted a formulaic approach to determining ROE and also set common equity ratios for each of the larger regulated utilities.

In February 2008, the AUC initiated a Generic Cost of Capital proceeding to review the generic ROE and capital structures of AUC regulated utilities (2009 GCC Proceeding).[123] The 2009 GCC Proceeding will review the level of the generic return on equity, the Generic ROE adjustment mechanism, and the capital structure of utilities on a utility specific basis. The 2009 GCC Proceeding is set to proceed from 19 May 2009 to 30 June 2009.

3. NEB DECISION RH–3–2008: *ENBRIDGE PIPELINES INC.*[124]

"Line 9" was built by Interprovincial Pipe Line Limited (IPL), now Enbridge, and initially provided eastbound crude oil service from Sarnia, Ontario to Montreal, Quebec. In 1997, Enbridge received NEB approval to reverse the direction of flow to provide westbound service for offshore crude petroleum. A Facilities Service Agreement (the FSA) was entered into between IPL and Line 9 shippers under which financial support for the reversal project was provided.

NOVA Chem operates a petrochemical facility in Corunna, Ontario (the Corunna Facility) producing ethylene and associated co-products. Approximately 75-90 percent of the Corunna Facility's light, sweet, crude, and condensate feedstock were transported westbound on Enbridge's Line 9, giving NOVA Chem a significant interest in ensuring that Line 9 maintained westbound service.

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121 Letter from National Energy Board to Various Parties (23 March 2009), online: NEB <http://www.neb-one.gc.ca>.

122 *Generic Cost of Capital* (2 July 2004), EUB Decision 2004-052, online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2004/2004-052.pdf>.

123 "2009 Generic Cost of Capital Proceeding," online: AUC <http://www.auc.ab.ca/applications/notices/Notices/2008/1578571.pdf>.

124 *Enbridge Pipelines Inc.* (April 2009), Reasons for Decision RH-3-2008 (NEB), online: NEB <http://www.neb-one.gc.ca> [*Enbridge Pipelines*].

Prior to the FSA's expiry, negotiations between Enbridge and Line 9 shippers regarding Line 9's continuation of westbound service on a long-term basis failed. This led to the RH-2-2007 proceeding wherein Enbridge applied to the NEB for the approval of new tolls and tariffs for Line 9.[125] In September 2007, Enbridge and Imperial Oil Limited (Imperial), another Line 9 shipper, bilaterally negotiated and finalized a term sheet for a new Transportation Service Agreement (TSA) for westbound service. Under the TSA, Imperial committed to ship monthly volumes on a take-or-pay basis, allowing Enbridge to recover its full revenue requirement for Line 9 over five years. In exchange, on 12 September 2007, Enbridge withdrew the RH-2-2007 application and agreed to conduct an open season.[126] The FSA expired on 30 September 2007. The TSA was supplemented by a confidential MOU between Enbridge and Imperial that contemplated the future re-reversal of Line 9 in 2013 with a view to capitalizing on an anticipated increase in oil sands and crude oil volumes in eastern Alberta. NOVA Chem was not part of these negotiations and was unaware of the MOU's existence until it was disclosed in the NEB proceedings.

Enbridge applied to the Board for approval of the TSA. The TSA incorporated take-or-pay obligations for committed shippers for five-year terms and stipulated a 20 percent premium on uncommitted tolls.[127] A shipper who terminated during the term would be obliged to pay its share of the debt portion of the outstanding rate base, plus associated tax allowances. Initial committed tolls escalated annually by 75 percent of each year's gross domestic product implicit price index, which provided toll certainty to Imperial. Enbridge or a shipper would only be able to request a recalculation of recommitted tolls on a cost-of-service basis once every five years. The TSA would terminate if any future agreement regarding the re-reversal of Line 9 was reached.[128]

Throughout the open season, prospective shippers were provided with the opportunity to subscribe for transportation service on Line 9. Prior to the close of the open season, Imperial and NOVA Chem each executed copies of the TSA. Enbridge did not accept NOVA Chem's TSA because it did not meet Enbridge's credit requirements and, as a result, was not eligible for service as a committed shipper.[129] Enbridge had requested a $33.2 million letter of credit from NOVA Chem that allegedly would have cost NOVA Chem $1 million annually to sustain.[130] At the close of the open season, Imperial represented 42 percent of the total estimated capacity on Line 9.

NOVA Chem had significant concerns with respect to the toll design and conditions of service Enbridge sought to implement. NOVA Chem further argued that its exclusion from the processes leading up to the open season breached the Board's objective of ensuring open and transparent exchanges of information to prevent unjust discrimination in services and tolls. With respect to the financial requirements of the TSA, NOVA Chem argued that it was placed in a no-win situation to: (1) provide a $33.2 million letter of credit in order to qualify for a less desirable long-term service than that provided under the FSA; or (2) not only pay

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125 *Enbridge Pipelines Inc.: Line 9 Application — Tolls and Tariffs* (11 April 2007), online: NEB <http://www.neb-one.gc.ca>.

126 *Enbridge Pipelines*, *supra* note 124 at 5.

127 *Ibid.* at 10.

128 *Ibid.*

129 *Ibid.* at 5.

130 *Ibid.* at 15.

a premium toll for Line 9 service, but to have virtually the entire toll revenue paid by NOVA Chem used as a rebate for the benefit of Imperial.

In its decision, the Board held that the discussions prior to the open season should have included NOVA Chem, especially as they were now one of the two remaining shippers on the pipeline. In addition, the TSA and open season documents should have been more explicit with respect to both the financial assurance requirements and any potential re-reversal plans that would significantly affect NOVA Chem's commercial dealings.[131]

The Board opined that while there may be circumstances where Enbridge's proposed revenue sharing mechanism would be appropriate, crediting the net excess revenue to one shipper rather than to the revenue requirement was unfair to NOVA Chem. The Board found the TSA to be beneficial to Imperial while being "unduly discriminatory" to NOVA Chem, owing to the fact Imperial would receive all of the benefits of the revenue sharing mechanism while NOVA Chem's access to committed shipper status was restrained by the imposition of unreasonable financial assurances.[132] The Board held that it would be contrary to the public interest to unduly restrain NOVA Chem from access to committed shipper status by approving a toll design that generated the need for financial assurances of the nature requested by Enbridge. As such, the Board found the TSA to be unacceptable and denied the application.

III. OIL SANDS

A. MINING, IN SITU PRODUCTION, UPGRADING PROJECT APPROVALS

1. *DIRECTIVE 073: REQUIREMENTS FOR INSPECTION AND COMPLIANCE OF OIL SANDS MINING AND PROCESSING PLANT OPERATIONS IN THE OIL SANDS MINING AREA*[133]

Released on 17 December 2008, the purpose of *Directive 073* is to ensure that mineable oil sands mining operations and processing plants are inspected in a uniform and consistent manner by ERCB inspection staff. This directive is also intended to inform the licensee as to what is required to achieve a satisfactory ERCB inspection. This directive details the ERCB minimum requirements that operators of oil sands mining and processing plant operations must follow. The requirements are based on existing legislation, directives, interim directives, information letters, manuals, and agreements. The requirements referred to in those documents are now enforceable under *Directive 073*. Confirmed situations of non-compliance are enforced in accordance with *Directive 019: EUB Compliance Assurance — Enforcement*.[134] *Directive 073* provides an inspection checklist that ERCB inspectors must complete when conducting a physical inspection of a production facility. The checklist is also

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131 *Ibid.* at 9.
132 *Ibid.* at 17.
133 Energy Resources Conservation Board, *Directive 073: Requirements for Inspection and Compliance of Oil Sands Mining and Processing Plant Operations in the Oil Sands Mining Area* (Calgary: Energy Resources Conservation Board, 2008) [*Directive 073*].
134 Energy Resources Conservation Board, *Directive 019: EUB Compliance Assurance – Enforcement* (Calgary: Energy Resources Conservation Board, 2007) [*Directive 019*].

to be used if a facility is inspected as the result of a complaint or when a facility is inspected by the ERCB air monitoring unit.

B. CONSULTATION

1. ERCB DECISION 2009-002: *PETRO-CANADA OIL SANDS INC.: APPLICATION TO CONSTRUCT AND OPERATE AN OIL SANDS UPGRADER IN STURGEON COUNTY*[135]

On 20 January 2009, the ERCB approved Petro-Canada Oil Sands Inc.'s (PCOSI) application to construct and operate a 54,000 m^3/day oil sands upgrader in Sturgeon County. The project would be developed in two phases. Phase 1 would process 26,400 m^3/day of bitumen and phase 2 would process a cumulative total of 54,000 m^3/day of bitumen, with both phases producing synthetic crude oil, petroleum coke, sulphur, diluent, and other light hydrocarbon products.

A public hearing into the application was held in Fort Saskatchewan, Alberta commencing 23 June 2008 and concluding 4 July 2008. On 13 August 2008, the ERCB requested additional information from PCOSI, respecting the impacts of proposed work camps. The Board reopened the hearing on 21 October 2008 to consider additional evidence submitted by PCOSI and some of the interveners. Among other things, the interveners were concerned about the impact that work camps would have on traffic, availability of medical services, and the safety and security of people and their property in the area. The hearing record was completed on 10 November 2008.

Prior to the public hearing, the Métis Nation of Alberta (MNA) filed a notice of constitutional question with the ERCB. The notice raised the following question:

> Has the Crown discharged its duty to consult the Métis Nation of Alberta … with respect to potential infringements of Aboriginal rights protected under section 35(1) of the *Constitution Act, 1982* which may arise if Application No. 1490956 to the Energy Resources Conservation Board is granted approval for construction and operation of the proposed Fort Hills Sturgeon Upgrader and associated infrastructure in Sturgeon County.[136]

Alberta Justice subsequently advised the ERCB that it intended to challenge the Board's jurisdiction to consider the constitutional question because the notice did not comply with the requirements of the *Administrative Procedures and Jurisdiction Act*.[137] The ERCB considered the jurisdiction question as a preliminary motion at the outset of the hearing.

In arguing the preliminary motion, the MNA informed the ERCB that it was seeking intervener status under s. 26 of the *ERC Act* (that is, as a party whose rights are directly and adversely affected by the PCOSI application) based upon rights provided under s. 35 of the

135 *Petro-Canada Oil Sands Inc.: Application to Construct and Operate an Oil Sands Upgrader in Sturgeon County* (20 January 2009), ERCB Decision 2009-002, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2009/2009-002.pdf> [*Petro-Canada*].

136 *Ibid.* at 5.

137 R.S.A. 2000, c. A-3 [*APJ Act*].

Canadian Charter of Rights and Freedoms.[138] The MNA clarified that it was not asking the ERCB for a declaration that PCOSI had not engaged in appropriate consultation, but rather to defer the decision on the PCOSI application to allow the necessary consultation to take place. The MNA submitted that since it was not challenging the constitutional validity of any legislation it was not necessary to strictly adhere to the 14-day notice requirement under the *APJ Act*. The MNA also argued that some of its members were landowners living in proximity to the project and would be entitled to participate in the proceeding based upon rights arising from a number of sources, including s. 7 of the *Charter*.[139]

PCOSI argued that the MNA notice was deficient as having failed to meet the requirements of the *APJ Act*. PCOSI took the position that, under s. 10(d) of the *APJ Act*, a question of constitutional law included a determination of any right under the Constitution or the *Alberta Bill of Rights*.[140] Because the MNA notice did not meet the statutory filing requirements, the Board had no jurisdiction to consider the question it had raised. PCOSI did not object to the MNA participating in the hearing.

Alberta Justice made similar arguments and also argued that the notice was deficient because it did not describe the witnesses whom the MNA intended to call or the documents upon which it intended to rely.

The MNA responded that the ERCB's duty to provide fair process pursuant to Part 1 of the *APJ Act* overrode the notice provision in s. 12 of the *APJ Act*.

The ERCB held that it lacked jurisdiction to consider the MNA application as the MNA failed to meet the notice requirements in s. 12 of the *APJ Act*.[141] The ERCB also denied the MNA application for intervener status under s. 26 of the *ERC Act* on the basis that the Board had insufficient information on which to make such a determination. The ERCB nevertheless permitted the MNA to participate in the proceeding as a "discretionary participant," and to make a short submission.[142] The MNA was cautioned that the ERCB could not consider any constitutional question, as defined in the *APJ Act*, and specifically any issues regarding the MNA's Aboriginal rights, including a right to meaningful consultation from the Crown or any issues concerning individual MNA members relating to s. 7 of the *Charter*.[143]

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138 Part I of the *Constitution Act, 1982*, being Schedule B to the *Canada Act 1982* (U.K.), 1982, c. 11 [*Charter*].

139 *Petro-Canada*, *supra* note 135 at 5.

140 R.S.A. 2000, c. A-14.

141 *Petro-Canada* supra note 135 at 6, 96-97.

142 *Ibid.* at 6.

143 This decision is also noteworthy for its discussion of the motion by one of the intervener groups to compel the attendance of employees of AENV as witnesses in the hearing. The party bringing the motion sought to cross-examine AENV employees regarding, among other things, the environmental impact assessment review process and the decision to declare the environmental impact assessment complete. The ERCB applied a two-part test in considering the motion, which was denied. Specifically, the Board considered the questions: "(i) is the evidence sought in the motion critical to the Board's understanding of the issues before it?"; and, "(ii) is there no other reasonable means by which the evidence can be adduced?" (*ibid.* at 4). The ERCB was not convinced that the evidence that the intervener group was seeking was critical to its understanding of the issues raised by the PCOSI application and found that evidence regarding the issues of concern could be best obtained from witnesses for the parties to the proceeding, including PCOSI and the intervener group itself (at 4-5).

2. AEUB DECISION 2008-015: *CANADIAN NATURAL RESOURCES LIMITED: APPLICATION TO AMEND APPROVAL NO. 6280 (PRIMARY RECOVERY SCHEME) COLD LAKE OIL SANDS AREA*[144]

On 19 February 2008 the ERCB approved an application by Canadian Natural Resources Limited (CNRL) to amend the approval for a primary recovery scheme for crude bitumen production in, and in the vicinity of, the Fishing Lake Métis Settlement (FLMS). CNRL sought to add certain lands to its production scheme and approval of reduced drilling spacing units for the lands in the production area.

FLMS objected to the CNRL application (which had been outstanding for two years by the time the hearing was convened) on the basis that, if approved, the scheme would significantly increase the number of wells located in the area and result in increased surface impacts. FLMS also contended that "CNRL had not made any significant attempt to mitigate the effects on cultural and traditional losses that would be sustained in the area."[145] Further concerns were expressed that CNRL had not complied with the terms of a Master Development Agreement between CNRL and FLMS relating to the existing approval. Finally, FLMS was concerned that, since the mineral leases were granted prior to the *Alberta-Métis Settlements Accord*,[146] the mineral extraction on the lands did not provide any benefits to FLMS.[147] It was argued by CNRL that the "real issue in the hearing was that the mineral rights to the oil sands in the application area were acquired prior to the the *Métis Settlement Act* and were not subject to a co-management agreement."[148]

In the end result, the ERCB concluded that the "reduced spacing is necessary to effect conservation of the bitumen resource and furthers the orderly, efficient, and economical development of the resource."[149] The ERCB observed that the issues in applications for reduced spacing within an oil sands scheme are subsurface issues related to the reservoir and the number of subsurface drainage locations necessary to maximize bitumen recovery. Generally, potential surface impacts and operational matters are not issues in a hearing on a scheme application. Nevertheless, the Board was of the view that this particular application was unique because it would be situated on lands forming part of the FLMS that are governed by a specific legal regime. The ERCB wished to provide an opportunity to the FLMS to address the interplay between the application, the applicable legislation, and the FLMS concerns.[150]

CNRL argued that surface-related concerns were best addressed at the well licence consultation or application stage. FLMS responded that it had raised its concerns about potential surface impacts and operational issues during the spacing application because that application marked the first step in a CNRL plan to significantly increase development in an

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144 *Canadian Natural Resources Limited: Application to Amend Approval No. 6280 (Primary Recovery Scheme) Cold Lake Oil Sands Area* (19 February 2008), EUB Decision 2008-015, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2008/2008-015.pdf>.

145 *Ibid.* at 1.

146 *Alberta-Métis Settlements Accord* (Edmonton: Government of Alberta, 1989).

147 *Ibid.*

148 *Ibid.* at 4.

149 *Ibid.* at 3.

150 *Ibid.* at 2.

undeveloped area of the FLMS. CNRL expressed its commitment to work with the FLMS to minimize any surface impacts resulting from the operations, including the use of multiwell pads. The FLMS agreed that multiwell pads would reduce the surface disturbance but that alone did not allay either its concerns about the impact of increased development on lands available to its members for traditional and cultural uses, or increased heavy truck traffic. The FLMS also understood that further well and facility applications would provide opportunities to address surface issues and that the Métis Settlements Appeals Tribunal offered a process in which access issues could be addressed in the absence of an agreement between the parties.

Compensation was also raised as an issue, however the ERCB noted that "the Métis Settlements Appeals Tribunal has jurisdiction in disputes regarding rights of entry and compensation relating to access to Métis Settlement lands."[151]

Finally, the Board made it clear that approval of the reduced spacing application did not predetermine any facility licence application for the project area. Rather, CNRL would be required to make all facility applications in accordance with ERCB *Directive 056: Energy Development Applications and Schedules*[152] and the FLMS would have an opportunity to submit its concerns about, or objections to, such applications. In the view of the ERCB, the well or facility application process was the better forum in which questions regarding surface impacts can be adjudicated.

C. ENVIRONMENTAL IMPACT ASSESSMENT

1. *Pembina Institute for Appropriate Development v. Canada (Attorney General)*[153]

In February 2007, a Joint Review Panel (JRP) established by the AEUB and the Government of Canada issued an environmental impact assessment (EIA) of the Kearl Oil Sands Project under the Alberta *Environmental Protection and Enhancement Act*[154] and the *Canadian Environmental Assessment Act*.[155] The JRP recommended that the Department of Fisheries and Oceans (DFO) authorize the project. As reported in " Recent Regulatory and Legislative Developments of Interest to Oil and Gas Lawyers 2007-2008," a number of environmentally based non-governmental organizations brought an application for judicial review of this report on the basis that, among other things, the JRP had failed to adequately address issues relating to greenhouse gas (GHG) emissions.[156]

Briefly, as noted by the Federal Court, the evidence showed that the proposed project would result in absolute GHG emissions equivalent to 800,000 passenger vehicles per year. The project proponent suggested that it would limit GHG emissions on an emissions intensity

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151 *Ibid.* at 6.

152 Energy Resources Conservation Board, *Directive 056: Energy Development Applications and Schedules* (Calgary: Energy Resources Conservation Board, 2008) [*Directive 056*].

153 2008 FC 302, 323 F.T.R. 297 [*Pembina*].

154 R.S.A. 2000, c. E-12 [*EPEA*].

155 S.C. 1992, c. 37 [*CEAA*].

156 John E. Lowe & Jonathan M. Liteplo, "Recent Regulatory and Legislative Developments of Interest to Oil and Gas Lawyers 2007-2008" (2009) 46 Alta. L. Rev. 521; see also: John C. Goetz *et al.*, "Development of Carbon Emissions Trading in Canada" (2009) 46 Alta. L. Rev. 377.

basis and not on an absolute basis. The JRP accepted this proposed mitigation measure but failed to provide any rationale for holding that the elevated GHG emissions would not result in significant adverse environmental effects.[157]

In its decision, the Federal Court found that while the JRP was "not required to comment specifically on each and every detail of the project," it was required to provide a "clear and cogent articulation" as to why intensity based mitigation would be effective in reducing absolute emissions.[158] The Court remitted the matter back to the JRP to provide an explanation and rationale for its decision.

2. *IMPERIAL OIL RESOURCES VENTURES LTD. V. CANADA (MINISTER OF FISHERIES AND OCEANS)*[159]

Upon acceptance of the recommendation of the JRP, discussed above, the Minister of Fisheries and Oceans granted an authorization pursuant to s. 35(2) of the *Fisheries Act*[160] to allow Imperial Oil to commence work on the project. The *Fisheries Act* authorization was granted and relied upon by Imperial Oil while the judicial review in *Pembina*[161] was under reserve for decision by Tremblay-Lamer J.

Upon release of Tremblay-Lamer J.'s decision in *Pembina*, a delegate of the Minister of Fisheries and Oceans, in a faxed letter to Imperial Oil dated 20 March 2008, stated the opinion that the authorization already granted was now a nullity and, as a result, Imperial Oil was not authorized to proceed on the project. Imperial Oil challenged the Minister of Fisheries and Oceans' opinion in order to allow it to proceed on the project on the basis of the authorization already granted.[162]

Imperial Oil first moved to obtain an injunction against the implementation of the opinion of the Minister of Fisheries and Oceans. At that time, the Pembina Institute for Appropriate Development and the Sierra Club of Canada had already commenced a separate application to quash the authorization. At the hearing of the injunction motion, both matters were before Justice de Montigny who sought and obtained an agreement by all parties to deal with the key issues in both applications in the judicial review conducted by Justice Campbell. The parties agreed that the key issues were as follows:

1. What is the effect of the Tremblay-Lamer J.'s judgment on the validity of the authorization? More specifically, is the authorization rendered a nullity as a result of the operation of law?

2. If the authorization is not rendered a nullity by the judgment, should the Court quash the authorization?

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157 *Pembina, supra* note 153 at para. 78.
158 *Ibid.* at paras. 78-79.
159 2008 FC 598, 36 C.E.L.R. (3d) 153 [*Imperial Oil*].
160 R.S.C. 1985, c. F-14.
161 *Supra* note 153.
162 *Imperial Oil, supra* note 159 at para. 3, App. A.

3. If the authorization remains legally valid, does the DFO or its Minister have the legal authority to rescind the authorization?[163]

Justice Campbell found that the primary effect of Tremblay-Lamer J.'s order was that the JRP's report was incomplete, and that once completed it must again be placed before the Governor in Council for approval upon which a new authorization would have to be provided by the Minister of Fisheries and Oceans to allow Imperial Oil to proceed with the project. He noted that the secondary effect of Tremblay-Lamer J.'s decision was that the authorization issued by the Minister of Fisheries and Oceans on a fundamentally flawed JRP report could not lawfully receive the approval of the Governor in Council and, as a result, was issued without jurisdiction and therefore a nullity.[164]

Imperial Oil argued that Campbell J. should exercise his discretion not to act on the finding that the authorization was made in an error of law because Imperial Oil was without fault in the issuance of the flawed JRP report. Justice Campbell refused to exercise his discretion on the basis that since the authorization was a nullity, nothing existed upon which for him to exercise his discretion.

Justice Campbell noted that, based on his finding in the first issue, the second issue was irrelevant. With respect to the third issue, Campbell J. found that the opinion given by the delegate of the Minister of Fisheries and Oceans did not constitute a revocation, but rather was an expression of opinion based on operation of law. He therefore also found that issue to be irrelevant.[165]

Imperial Oil's application was dismissed as were the applications of the Pembina Institute for Appropriate Development and the Sierra Club of Canada.

3. ERCB DECISION 2009-002: *PETRO-CANADA OIL SANDS INC.: APPLICATION TO CONSTRUCT AND OPERATE AN OIL SANDS UPGRADER IN STURGEON COUNTY*

As set out at Part III.B, above, the ERCB issued its decision regarding PCOSI's application to construct and operate an oil sands upgrader in January of 2009.[166]

A great deal of the ERCB's decision focused on the potential environmental impacts of the project. The Northeast Sturgeon County Industrial Landowners and the Citizens for Responsible Development (NESCIL/CFRD) raised key issues regarding air emissions and the dispersion modelling conducted by PCOSI. The ERCB determined that PCOSI's air quality assessment was satisfactory and the emissions estimates were completed using sound engineering judgment. Furthermore, the EIA was complete and the air quality assessment was in accordance with AENV terms of reference.[167]

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163 *Ibid.* at para. 4.
164 *Ibid.* at para. 6.
165 *Ibid.* at para. 8.
166 *Petro-Canada*, *supra* note 135.
167 *Ibid.* at 31.

The ERCB requires all new upgraders to achieve a minimum calendar quarter-year sulphur recovery of 99.5 percent within six months of commencing start-up activities. In its application, PCOSI sought to deviate from the Board's normal practice and delay achieving overall recovery for 12 months. The ERCB found no reason to deviate from this practice in the case of PCOSI and denied this aspect of the application.[168]

In regard to the upgrader design, the ERCB agreed with PCOSI's view that it had incorporated the Best Available Technology Economically Achievable (BATEA) in all aspects of its design. NESCIL/CFRD disagreed. The ERCB noted that there was "no standard definition of what emission reduction strategies conform to BATEA and that economic achievability is subjective."[169] The ERCB acknowledged that PCOSI's sulphur recovery efficiency met the ERCB's sulphur recovery guidelines as required in AEUB Decision 2007-058.[170] The ERCB also noted that PCOSI chose to install selective catalytic reduction (SCR) technology on its largest nitrogen oxides (NOx) source but took the view that PCOSI could reduce NOx emissions further by installing SCR on other sources. The ERCB recognized that further emission reductions may be required in the future through the Alberta Industrial Heartland emission caps and Ozone Management Plan for the Edmonton Census Metropolitan Area.[171]

Dr. Du, an expert witness for the interveners submitted that PCOSI's emission estimates were underestimated by a factor of 13.45. In its decision, the ERCB determined that PCOSI had adequately refuted Dr. Du's analysis. The ERCB noted that it expected experts at ERCB hearings to have a better understanding of the material before making "definitive and potentially alarmist statements."[172]

Interveners also expressed concern with changes to upgrader design since the completion of PCOSI's air modelling work. The ERCB conditioned PCOSI's approval on PCOSI providing a revised estimate of fugitive emissions. These estimates were to be prepared after the design of the facility had been finalized and prior to start-up, to ensure that the original fugitive emissions estimates were reasonable.

The ERCB noted PCOSI's commitment to re-run dispersion modelling using an alternate program at the request of the intervener's and incorporated this as a condition to approval. The ERCB acknowledged that the modelling predicted exceedance of the one-hour sulphur dioxide (SO_2) Alberta Ambient Air Quality Objective (AAAQO), but noted that it occurred infrequently.[173] Considering the conservatism in the modelling, the infrequency and location of predicted exceedances, and the magnitude of the predictions, the ERCB found that it was

[168] *Ibid.*
[169] *Ibid.*
[170] *North West Upgrading Inc.: Application to Construct and Operate an Oil Sands Upgrader in Sturgeon County* (7 August 2007), EUB Decision 2007-058, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-058.pdf>.
[171] *Petro-Canada, supra* note 135 at 32.
[172] *Ibid.*
[173] The SO_2 exceeded the AAAQO on the order of two hours per year at the worst off-site receptor. The maximum concentration predicted was 461 micrograms per cubic metre, only slightly higher than the objective of 450 micrograms per cubic metre: *ibid.* at 33.

"unlikely that the predicted SO_2 exceedances [would] occur and therefore SO_2 emissions from the proposed upgrader pose a very low risk to the health and safety of the public."[174]

The ERCB also noted PCOSI's modelling demonstrated exceedance of the Canada-wide standard for particulate matter and the AAAQO for hydrogen sulphide (H_2S) and SO_2 in all scenarios. The ERCB found that the predicted exceedances of particle matter were mainly due to existing emissions from non-industrial sources in Edmonton and Fort Saskatchewan and exceedances of H_2S and SO_2 were localized around existing, approved, and proposed industrial facilities. The ERCB held "the contribution of the proposed upgrader to these exceedances is negligible."[175]

Many conflicting views were presented about ambient air monitoring by the Fort Air Partnership (FAP). NESCIL/CFRD said that the FAP was not doing a credible job in monitoring the air whereas PCOSI maintained that the FAP "was doing a good job, the current monitoring network was adequate and credible, and [the] FAP was fulfilling its mandate."[176] The ERCB recognized that the FAP was given the responsibility of collecting and disseminating ambient air quality in the region by AENV, but noted there was some confusion about the FAP's role. The ERCB stated that it believed the FAP "should operate with transparency and that information requests by the public should be answered in a timely manner."[177]

The ERCB recognized that further industrial development was planned for this area. Notwithstanding the regional emission caps proposed for the area, the ERCB strongly recommended to AENV that a terrestrial monitoring program be implemented to ensure that ecosystem health could be better quantified and problems could be identified earlier.[178]

The ERCB was satisfied that PCOSI's design would be carbon capture ready and that PCOSI would implement measures to reduce GHGs and maximize energy efficiency. The ERCB noted that AENV is responsible for regulation of GHG emissions under Alberta's *Climate Change and Emissions Management Act*.[179]

The ERCB concluded that, with respect to air issues in general, there was a need to "better coordinate its activities with those of AENV to provide for a more effective and comprehensive regulatory system."[180] The ERCB stated that it would conduct a review and contact AENV for that purpose.

The Human Health Risk Assessment (HHRA) was reviewed by Alberta Health and Wellness and Health Canada and, the ERCB found, conducted in accordance with accepted standards. The ERCB noted that the "primary objective of an HHRA is to provide a conservative estimate of the risk and significance of potential adverse effects on an individual, community, or population that could arise from changes in environmental quality

174 *Ibid.*
175 *Ibid.* at 34.
176 *Ibid.* at 37.
177 *Ibid.*
178 *Ibid.* at 39.
179 S.A. 2003, c. C-16.7 [*CCEMA*].
180 *Petro-Canada*, *supra* note 135 at 41.

due to a project" and to "ensure that any potential risks associated with a project are negligible or insignificant."[181] The NESCIL/CFRD raised its concern that groundwater and surface water exposure pathways were not included in the HHRA. However, the ERCB noted that "the EIA considered potential impacts … and concluded that groundwater and surface water quality would not be adversely affected." The ERCB therefore accepted the conclusion in PCOSI's HHRA that "the exposure pathways originating in groundwater and surface water need not be considered."[182]

In consideration of water usage and quality, the ERCB remarked that jurisdiction for water allocation rests with AENV under the *Water Act*.[183] AENV had concluded that the volume of water downstream of Edmonton is not under stress, despite NESCIL/CFRD's assertions. Based on PCOSI's drilling program and assessment of existing water wells, the ERCB accepted that PCOSI had a clear understanding of the hydrogeological conditions it was dealing with.[184]

Interveners had various concerns with PCOSI's Cumulative Effects Assessment (CEA). The ERCB noted that AENV deemed the EIA, which included the CEA, to be complete. However, the Board noted, a CEA merely predicts environmental changes that might reasonably be anticipated from the proposed activity in combination with other activities; a CEA is not meant to determine the extent of degradation a component can withstand. As there is a degree of uncertainty in the results of a CEA, PCOSI committed to monitor environmental impacts and respond to unfavourable outcomes, should they arise in the future. The ERCB also noted that three other upgrader applications were approved for the region and was encouraged by the focus on regional development by the Government of Alberta and multistakeholder groups.[185]

4. *MININGWATCH CANADA V. CANADA (MINISTER OF FISHERIES AND OCEANS)*[186]

This decision arose from an appeal of the decision of the Federal Court of Canada in *MiningWatch*.[187] In the decision under appeal, the Court granted an application for judicial review and ordered that public consultation be held on the proposed scope of a proposed mining and milling operation in northwestern British Columbia to be subjected to an environmental assessment under the *CEAA*.

At issue on appeal was the question of whether a responsible authority — here the DFO and Natural Resources Canada (NRCan) — "have the discretion to define and redefine the 'scope' of a project for the purposes of tracking an environmental assessment as a screening (section 18) or as a comprehensive review (section 21) under the *CEAA*."[188]

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181 *Ibid.* at 42.
182 *Ibid.* at 43.
183 R.S.A. 2000, c. W-3.
184 *Petro-Canada, supra* note 135 at 49.
185 *Ibid.* at 70.
186 *MiningWatch Canada v. Canada (Minister of Fisheries and Oceans)*, 2008 FCA 209, [2008] 2 F.C.R. 21 [*MiningWatch*].
187 2007 FC 955, [2008] 3 F.C.R. 84.
188 *MiningWatch*, *supra* note 186 at para. 2. In this context, "tracking" refers to the process under which an environmental assessment is to be conducted, e.g., screening report, comprehensive study, or review panel.

The project proponents, Red Chris Development Company Ltd. and bcMetals Corporation, had submitted an application for a gold and copper open pit mining and milling project to the BCEAO in October 2003. In May 2004, the proponents submitted two applications to the DFO for construction of starter dams related to tailings impoundment and stream crossings. These applications triggered the federal environmental assessment process and made the DFO a responsible authority under the *CEAA*.

The DFO determined that an environmental assessment was required under ss. 5(1)(d) and 5(2)(a) of the *CEAA* and later posted a notice on the *CEAA* Registry announcing that the DFO would conduct a comprehensive study of the project. The DFO also circulated a letter to other federal departments allowing them to determine whether they considered the project to be relevant to their jurisdiction. NRCan responded to the DFO that it was likely also a responsible authority since explosives, and their storage, were to be used in operating the proposed mine and authority under the *Explosives Act*[189] would be required.

The CEA Agency, the responsible authorities (that is, the DFO and NRCan), and the BCEAO met to coordinate the environmental assessment. Following these meetings the DFO wrote to the Agency stating that upon further review and as a result of new fisheries information and the decision of the Federal Court in *Prairie Acid Rain Coalition v. Canada (Minister of Fisheries and Oceans)*,[190] the scope of the project required only a screening report.

The Notice of Commencement of the environmental assessment on the *CEAA* Registry was subsequently amended three times, the last iteration stating that the scope of the project for the purposes of the environmental assessment under the *CEAA* would be:

> [T]he construction, operation, modification and decommissioning of the following physical works: Tailings Impoundment Area including barriers and seepage dams in the headwaters of Trial, Quarry and NE Arm creeks. Water diversion system in the headwaters of Trail, Quarry, and NE Arm creeks. Ancillary Facilities supporting the above mentioned (i.e. process water supply pipeline intake) on the Klappan River. Explosives storage and/or manufacturing facility on the mine property.[191]

The responsible authorities completed the environmental screening and concluded that "taking into account the implementation of the mitigation measures, the Project is not likely to cause significant adverse environmental effects."[192] A Course of Action Decision, pursuant to s. 20(1)(a) of the *CEAA*, followed in which the responsible authorities determined that the project as they had scoped it was not likely to cause significant adverse environmental effects.[193]

MiningWatch brought an application before the Federal Court seeking judicial review of the Course of Action Decision. The application was granted and the Course of Action Decision was quashed. The Court also declared that the DFO had correctly determined in the

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189 R.S.C. 1985, c. E-17.
190 2004 FC 1265, 257 F.T.R. 212.
191 *MiningWatch*, *supra* note 186 at para. 19.
192 *Ibid.* at para. 22.
193 *Ibid.* at para. 23.

initial tracking decision of May 2004 that the project would require a comprehensive study level review.

At the Federal Court of Appeal, the appellants argued that the court below had erred in not applying *TrueNorth*.[194] In *TrueNorth*, the Federal Court of Appeal held that it was appropriate for a responsible authority to scope a project more narrowly than proposed by the proponent, so as to include only those aspects of the proposal related to the responsible authority's jurisdiction and responsibility under s. 5 of the *CEAA*. The appellants argued that the scoping of the Red Chris/bcMetals project by the responsible authorities preceded the determination of whether the assessment would be a screening or comprehensive study and that the "first appearance of the word 'project' in sections 18 and 21 should be read as 'project as scoped.'"[195]

MiningWatch countered that the wording of s. 21 indicates that the responsible authority may not decide the scope of a project until it determines if the project requires a comprehensive study. If a comprehensive study is required, then the scope should not be determined until the public has been consulted in that regard.

Although MiningWatch conceded that *TrueNorth* would otherwise be determinative of the issue, it took the position that subsequent amendments to s. 21 of the *CEAA* (that came into effect 30 October 2003) ensured that, once a project is determined to be within the *Comprehensive Study List Regulations*,[196] the public must be consulted regarding the scope of the project before the responsible authorities make their scope of project determination under s. 15. MiningWatch argued that, since the mine and milling project fell clearly within the *List Regulations*, public consultation was required regarding the proposed scope of the project, the factors proposed to be considered, the proposed scope of those factors, and the ability of the comprehensive study to address issues relating to the project. The responsible authority must then report on the scope of the project and recommend to the Minister whether to continue with the assessment as a comprehensive study or to refer it to mediation or review panel.[197]

Justice Desjardins, writing for the Court, considered the case law that preceded the amendments to s. 21 of *CEAA*. In particular, the Court considered the decision of the Federal Court of Appeal in *Friends of the West Country Assn. v. Canada (Minister of Fisheries and Oceans)*,[198] where the Court decided that s. 15(1) of *CEAA* gave the responsible authority the power to determine the scope of the project in relation to which type of environmental assessment is required. That decision also established that the assessment is to be carried out

194 *Prairie Acid Rain Coalition v. Canada (Minister of Fisheries and Oceans)*, 2006 FCA 31, [2006] 3 F.C.R. 610 [*TrueNorth*].

195 *MiningWatch*, *supra* note 186 at para. 29. The relevant parts of the *CEAA*, *supra* note 155, s. 18(1), state: "Where a project is not described in the comprehensive study list or the exclusion list made under paragraph 59(c), the responsible authority shall ensure that (a) a screening of the project is conducted; and (b) a screening report is prepared." Section 21(1) provides as follows: "Where a project is described in the comprehensive study list, the responsible authority shall ensure public consultation with respect to the proposed scope of the project for the purposes of the environmental assessment, the factors proposed to be considered in its assessment, the proposed scope of those factors and the ability of the comprehensive study to address issues relating to the project."

196 S.O.R./94-638 [*List Regulations*].

197 *MiningWatch*, *supra* note 186 at para. 32

198 [2000] 2 F.C. 263.

on the "project as scoped" according to s. 15(3). *TrueNorth* similarly established that "project," as it appears in para. 5(1)(d) of the *CEAA*, means "project as scoped" under s. 15(1).[199]

Justice Desjardins was of the opinion that, considering that "project" means "project as scoped" for purposes of para. 5(1)(d) and s. 15(3), the rules of statutory interpretation require that the same definition apply where "project" first appears in ss. 18 and 21 of the *CEAA*.[200] More specifically, although the amendments to s. 21 had added a requirement for public consultation, the introductory text to the section (that is, "[w]here a project is described in the comprehensive study list"[201]) remained the same. Thus, s. 21(1) of the *CEAA* is to be read as indicating that where the project "as scoped" is described in the *List Regulations*, a public consultation is required. Further, until a final decision has been made with respect to the environmental assessment, nothing prevents a responsible authority or responsible authorities from re-scoping the project — even after a public consultation has been announced. In summary, s. 21 of the *CEAA* did not operate in this instance because the project "as scoped" did not fall within the *List Regulations*.

MiningWatch was granted leave to appeal the Federal Court of Appeal decision to the Supreme Court of Canada on 18 December 2008.[202]

D. TAILINGS

1. *DIRECTIVE 074: TAILINGS PERFORMANCE CRITERIA AND REQUIREMENTS FOR OIL SANDS MINING SCHEMES*

Directive 074: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes[203] was released in February 2009. The purpose of this directive is to establish tailings performance criteria with appropriate enforcement actions to regulate tailings management at mineable oil sands developments. The ERCB, AENV, and Alberta Sustainable Resource Development (ASRD) worked together to develop the objectives associated with tailings management and establish performance based criteria.

The directive focuses on the reduction of fluid tailings volumes and the formation of trafficable deposits ready for reclamation, and applies to all existing, approved, and future oil sands operators. Operators are required to submit plans for dedicated disposal areas (DDAs) and annual tailings plans demonstrating how they will meet the directive. The ERCB has stated that they recognize that the technology is developing and that operators may require flexibility to meet the requirement of their project or operation.[204] Annual compliance reports for DDAs and pond status reports must be submitted to the ERCB in order to demonstrate performance against plans.

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199 *MiningWatch*, *supra* note 186 at para. 41
200 *Ibid.* at para. 48.
201 *CEAA*, *supra* note 155, s. 21(1).
202 *MiningWatch Canada v. Canada (Minister of Fisheries and Oceans)*, [2008] S.C.C.A. No. 393 (QL).
203 Energy Resources Conservation Board, *Directive 074: Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes* (Calgary: Energy Resources Conservation Board, 2009) [*Directive 074*].
204 *Ibid.* at 3.

Operators must submit a plan for approval by the ERCB for each DDA. The plans must be provided two years prior to construction and must specify dates for construction, use, closure, capping, and formation of trafficable deposits.[205]

Directive 074 will result in an amendment to the *Oil Sands Conservation Regulation*.[206] The requirements will be "phased in and adapted … to take account of particular mining and tailings plans, facilities, and the status of a project."[207] Tailings directive requirements will be enforced in accordance with *Directive 019*.

E. LAND MATTERS

1. *DIRECTIVE 068: ERCB SECURITY DEPOSITS*

Directive 068: ERCB Security Deposits[208] was issued by the ERCB on 15 May 2008. This directive updated and consolidated the liability management security deposit requirements currently contained in *Interim Directive 2001-1: Security Deposits*,[209] *Directive 006: Licensee Liability Rating (LLR) Program and Licence Transfer Process*,[210] and *Directive 024: Large Facility Liability Management Program (LFP)*.[211] This directive clarifies ERCB requirements for security deposits in the form of cash or lines of credit, provides information on their use and refund, and explains the allowance and acceptance of letters of credit.

Due to potential problems with use, forfeiture, or refund of a security deposit, the ERCB will only accept security deposits from a trustee, receiver, or receiver manager acting on behalf of that licensee. One licensee may not provide a security deposit for another licensee. The ERCB will only accept a cheque drawn from the account of the licensee or trustee, or a money order or bank draft identifying the licensee. The ERCB will only accept renewable, irrevocable lines of credit from a federally regulated bank as set out in the *Bank Act*,[212] the Alberta Treasury Branch, or an Alberta based credit union.[213]

The ERCB may use all or part of a security deposit to: properly suspend a well, facility, or pipeline; to abandon a well or facility; or to discontinue a pipeline if the licensee fails to comply with an ERCB order to do so. AENV "may use all or part of the security deposit placed with the ERCB by a licensee to undertake remediation or reclamation activities for wells, facilities, and pipelines located on 'specified lands.'"[214] ASRD may also "use all or part of the security deposit placed with the ERCB by a licensee to undertake remediation or

[205] *Ibid.* at 4.
[206] Alta. Reg. 76/1988.
[207] *Directive 074, supra* note 203 at 3.
[208] Energy Resources Conservation Board, *Directive 068: ERCB Security Deposits* (Calgary: Energy Resources Conservation Board, 2008) [*Directive 068*].
[209] Energy Resources Conservation Board, *Interim Directive 2001:01: Security Deposits* (Calgary: Energy Resources Conservation Board, 2001) (rescinded by *Directive 068*).
[210] Energy Resources Conservation Board, *Directive 006: Licensee Liability Rating (LLR) Program and Licence Transfer Process* (Calgary: Energy Resources Conservation Board, 2009).
[211] Energy Resources Conservation Board, *Directive 024: Large Facility Liability Management Program (LFP)* (Calgary: Energy Resources Conservation Board, 2009) [*Directive 024*].
[212] S.C. 1991, c. 46.
[213] *Directive 068, supra* note 208 at 2.
[214] *Ibid.* at 4.

reclamation activities for wells, facilities, and pipelines located on lands under its jurisdiction."[215]

IV. OIL AND GAS

A. WELL AND FACILITIES APPROVALS

1. EUB DECISION 2009-008: *ENCANA SHALLOW GAS INFILL DEVELOPMENT PROJECT*[216]

EnCana Corporation (EnCana) proposed drilling up to 1,275 shallow gas wells in the Canadian Forces Base Suffield National Wildlife Area (NWA) over a three-year period. The proposed project included pipelines and other associated infrastructure. On 16 November 2006, a JRP was named to undertake an environmental assessment of EnCana's proposed project and on 27 January 2009, the Panel released its decision with respect to the initial application for three wells together with its conclusions and recommendations on the overall project.

Technically, EnCana's narrow three well application would not trigger an assessment under Alberta's environmental legislation. However the AEUB, considering its mandate over environmental matters and the public interest more generally, decided to participate in a joint environmental assessment process with the federal government. EnCana was required to obtain a federal permit under the *Canada Wildlife Act*[217] and, as such, an assessment under the *CEAA* was necessary.

In the Panel's view, the main issues were the potential effects of the project on the native prairie grasslands and wildlife and the inter-jurisdictional regulatory process that applies to development in the NWA. The most active interveners in the proceeding were the Government of Canada and the Environmental Coalition. The federal government's general position was that there was insufficient information to determine whether the project was likely to cause significant adverse environmental effects; the Environmental Coalition opposed the project as it claimed there would be significant adverse environmental impacts.

Interestingly, shallow gas production had already taken place within the boundaries of the NWA since the mid-1970s. No fewer than 1,145 wells, pipelines, and associated infrastructure were already there.[218]

By way of brief background, the NWA was created in 2003 and, while the Province of Alberta owned the mineral rights under the NWA, the federal government owned the surface rights. An agreement between the two governments was signed in 1975 setting conditions for access to the minerals as well as creating the Suffield Environmental Advisory

215 *Ibid.*
216 *Report of the Joint Review Panel: EnCana Shallow Gas Infill Development Project — Canadian Forces Base Suffield National Wildlife Area, Alberta* (27 January 2009), EUB Decision 2009-008, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2009/2009-008.pdf> [*EnCana*].
217 R.S.C. 1985, c. W-9.
218 *EnCana*, *supra* note 216 at v.

Committee (SEAC) to deal with environmental protection in the area. Since that time, various new environmentally oriented pieces of legislation have been passed with application to the NWA. Although the NWA is managed by the Department of National Defence, military activity has been excluded from the area since 1971. The Panel referred to the NWA as "a nationally and internationally recognized area of environmental significance."[219]

Ultimately, the Panel found that it was not in the public interest to approve the application for the three wells, adding that the decision was "without prejudice to any future application that may be made for the three wells once [the Panel's] requirements are met for the overall project."[220] These requirements included the following:

1. Critical habitat for the Ord's kangaroo rat and the Sprague's pipet as well as three plant species (the tiny cryptanthe, the small-flowered sand verbena, and the slender mouse-ear-cress) were to be finalized;

2. Once the critical habitat was finalized, the proposed project facilities were *not* to be located in the critical habitat area unless permitted under the *Species at Risk Act*;[221] and

3. Clarification of the role of SEAC and the provision by the federal and provincial governments of adequate resources for it to "ensure proper regulatory oversight."[222]

Upon these requirements being met, the Panel held that "it may be possible to proceed with the project or part of it,"[223] however, further review would be necessary. In sum, the Panel found that

> the three-well application lacks complete and up-to-date pre-disturbance assessments for the proposed drilling sites. Given this shortcoming, the Panel finds that it is unable to fully assess the potential environmental impacts of the three proposed wells, as required by Section 3 of the *Energy Resources Conservation Act*.[224]

The *CEAA* enshrines the precautionary principle, discussed above, which, in general terms, states that if an action or policy might cause harm to the public or to the environment then, in the absence of scientific consensus that no harm will ensue, those who would advocate taking the action shoulder the burden of proving that such harm will *not* take place. Quite arguably, the application of this principle is evident in EnCana's proposed project in the NWA.

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219 *Ibid.* at vi.
220 *Ibid.* at viii.
221 S.C. 2002, c. 29.
222 *EnCana*, *supra* note 216 at vii. SEAC was found by the Panel to be incapable of overseeing a development of the magnitude proposed by EnCana.
223 *Ibid.*
224 *Ibid.* at viii. Some 27 additional recommendations were made in the Panel's 198-page report.

2. DECISION 2008-127: *SHELL CANADA LIMITED: APPLICATIONS FOR WELL, PIPELINE AND ASSOCIATED FACILITIES LICENSES — WATERTON FIELD*[225]

On 23 January 2007, Shell Canada Limited (Shell) applied to the AEUB for a license to drill a Level 3 critical sour gas well (the 10-1 well). In addition, between October 2006 and August 2007 Shell applied to construct and operate several pipelines and related facilities surrounding the 10-1 well. An application was also made to amend an existing facility by adding a new fuel gas compressor licensed for a maximum H_2S content of 32 percent (the 2007 Applications).

Several objections were made to the 2007 Applications on issues surrounding the environment, public safety, and air quality by, among others, the coalition Friends of Mount Backus (FOMB) and the Castle Crown Wilderness Coalition (CCWC).

One of Shell's other sour gas pipelines (some 3.2 kilometres from the proposed project) had sustained an uncontrolled release on 19 November 2007, resulting in the evacuation of area residents. Due to the controversy surrounding this release, the Board deferred consideration of the 2007 Applications until the ERCB had completed and released an investigation report (the Report).

In the interim, the ERCB had been asked to consider whether a public inquiry should be held into the Shell Waterton gathering system. Unsurprisingly, both FOMB and CWCC argued that the Board should deny the 2007 Applications and convene a public inquiry.

In its decision in the 2007 Applications, the Board confirmed, based on the Report, that the pipeline failure was not directly related to the proposed pipelines. The Report did stipulate that problems with the pipeline's corrodents had affected the release. The Board expressed some concern that Shell had not provided sufficient details in the 2007 Applications regarding the proposed pipeline's operation and monitoring with respect to corrodents. Further, a significant amount of time had passed since the 2007 Applications were made due to the delay of the release of the Report.[226] Since that time, changes had been made to the Board's application requirements, therefore, at a minimum, fresh evidence would be required to address new requirements for pipeline integrity and public safety. In the circumstances, and given: the uncertainties surrounding the timing of a reopened hearing process, the passage of time since the conclusion of the hearing of the 2007 Applications, the requirement to have additional submissions, the potential for an ERCB inquiry on the Shell gathering system, and the winding up of the AEUB, the Board found that considerations of the proposed development should be brought before the ERCB through fresh applications. The 2007 Applications were accordingly denied without prejudice to reapply in the future.[227]

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225 *Shell Canada Limited: Applications for Well, Pipeline, and Associated Facilities Licences — Waterton Field* (16 December 2008), EUB Decision 2008-127, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2008/2008-127.pdf>.

226 *Ibid.* at 5.

227 *Ibid.* at 6.

B. PUBLIC CONSULTATION AND STANDING

1. *GRAFF V. ALBERTA (ENERGY & UTILITIES BOARD)*[228]

This appeal stems from an application by EnCana Corporation (EnCana) to the AEUB for licences for two gas wells located in the vicinity of the lands and residence of the appellants, Barbara, Larry, and Darrell Graff (the Graffs). The first licence application was for a sour gas well located within two kilometres of the appellants' lands. The second licence application was for a sweet well 2.5 kilometres from the appellants' home. The Graffs objected to the approvals on the basis that resource extraction near their home would directly and adversely affect them due to pre-existing health conditions and sensitivity to chemicals.

Leading up to the application, EnCana had sent a notification package and project information to the Graffs and offered to meet with them to discuss their individual needs and potential "mitigative measures."[229] These efforts surpassed the minimum notification and consultation radii prescribed under the AEUB's *Directive 056* for the subject wells, which did not extend as far as the Graffs' properties and residence. The Graffs submitted letters objecting to EnCana's applications to the AEUB but provided no medical evidence to support their contention that they suffered from pre-existing health conditions and sensitivity to chemicals that would cause them to be potentially directly and adversely affected.

The AEUB dismissed the Graffs' objections and issued the well licences to EnCana. The Graffs requested a review and variance of the AEUB's decision, but still did not attach any medical evidence to their submissions to the AEUB. The AEUB declined to review the decisions on the basis that the Graffs had failed to demonstrate the potential for direct and adverse impact as required by s. 26 of the *ERC Act*. The AEUB also held that the Graffs had not demonstrated a reasonable connection between the impacts they claimed and the wells.[230]

The Court of Appeal granted leave to appeal the AEUB's decision denying the review and variance for both licence applications.[231] In regard to the sour gas well application, the Graffs were granted leave on the grounds that the AEUB erred in law or jurisdiction by: (1) granting the licence without affording the appellants a proper opportunity to be heard by the AEUB; (2) disregarding, misapplying, or misinterpreting AEUB *Directive 056* governing public disclosure and notification requirements; and (3) improperly fettering its discretion in failing to properly apply s. 26 of the *ERC Act*. Regarding the sweet gas well licence, leave was granted on largely the same basis; however, the Court held that the AEUB had also failed to take into account the cumulative effect of that well with other wells in the area.[232]

The Graffs sought to admit fresh evidence in the form of medical information on appeal, arguing that the fresh evidence would show that they would be directly and adversely affected by the wells. The AEUB also sought to adduce fresh evidence regarding medical evidence submitted by the Graffs to the AEUB in relation to other matters that the Graffs had

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228 2008 ABCA 119, [2008] A.J. No. 277 (QL) [*Graff*].
229 *Ibid.* at para. 5.
230 *Ibid.* at para. 10.
231 *Graff v. Alberta (Energy and Utilities Board)*, 2007 ABCA 20, [2007] A.J. No. 34 (QL).
232 *Graff v. Alberta (Energy and Utilities Board)*, 2007 ABCA 246, 30 C.E.L.R. (3d) 161.

requested be kept confidential. The AEUB's policy was that all information submitted to it was a matter of public record. Therefore, the AEUB maintained that the Graffs either had to agree to have their medical records made part of the public record, or make a confidentiality application in accordance with the *Rule 001: Rules of Practice*.[233] The Graffs did neither.

The Court of Appeal reviewed the test for admission of fresh evidence set out in *Palmer*,[234] which required that the evidence: (1) not be admitted if, by due diligence, it could have been adduced at trial; (2) bears upon a decisive or potentially decisive issue; (3) is credible or reasonably capable of belief; and (4) if believed, could reasonably, when taken with other evidence adduced at trial, be expected to have affected the result.[235] Although the Court found the new evidence did not meet the first criterion of *Palmer*, it determined that it was important it consider the evidence of both the appellants and the AEUB.[236]

In its decision, the Court held that the AEUB did not err in declining to review the issuance of the sour gas well licence on the basis that the appellants failed to prove their claims that their pre-existing health conditions may have been adversely affected.[237] While medical evidence was submitted to the Court on appeal, that evidence was not initially before the AEUB.

The Court of Appeal recognized that while the AEUB was bound to observe procedural fairness and meet the requirements of natural justice, it was not required to hold a hearing in these circumstances. As the AEUB had been asked to reconsider its earlier decisions, it was not unreasonable for it to require more than a mere assertion of the unusual sensitivity to the gas wells. There was no error or denial of natural justice when the AEUB ultimately declined to review its earlier decisions.[238]

The Court dismissed the appeals, noting that the subject wells had since been abandoned so there was little to be gained by ordering the AEUB to review the medical evidence. The Court noted, however, that the appellants could call this evidence if another well is commenced in the area of their lands and residence in the future.

2. ERCB DECISION 2008-135: *HIGHPINE OIL & GAS LIMITED APPLICATIONS FOR THREE WELL LICENCES — PEMBINA FIELD, TOMAHAWK AREA*[239]

On 30 December 2008, the ERCB approved applications by Highpine Oil & Gas Limited (Highpine) for three critical sour oil well licences in the Pembina Field in the vicinity of the

233 Alberta Utilities Commission, *Rule 001: Rules of Practice* (Calgary: Alberta Utilities Commission, 2009).
234 *Palmer v. The Queen* (1979), [1980] 1 S.C.R. 759 [*Palmer*].
235 *Ibid.* at 775.
236 *Graff, supra* note 228 at para. 19.
237 *Ibid.* at para. 22.
238 *Ibid.* at para. 25.
239 *Highpine Oil & Gas Limited: Applications for Three Well Licences — Pembina Field, Tomahawk Area* (30 December 2008), ERCB Decision 2008-135, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2008/2008-135.pdf> [*Highpine*].

Hamlet of Tomahawk, Alberta.[240] The approvals were made subject to several conditions imposed by the Board and more than 50 specific commitments that Highpine made in response to community and individual concerns.

Two of the proposed wells were new. The third involved deepening an existing wellbore into the Nisku Formation. The maximum hydrogen sulphide (H_2S) concentration expected to be encountered in drilling two of the three wells was 16 percent. The maximum H_2S release rate for drilling, completion, and servicing of two of the wells was determined to be 2.5 m^3/second and 1.51 m^3/second for the third well.[241] The Hamlet of Tomahawk and the Tomahawk School were encompassed within one or more of the EPZs that Highpine had adopted.[242]

The Highpine applications were addressed by the ERCB in a public hearing in Tomahawk commencing 23 September 2008 and ending 3 October 2008. Interveners included Parkland County, Parkland School Division, and a number of community members resident within one or more of the EPZs.[243] Some of the community members formed a group that they called the Concerned Citizens of Rural Tomahawk (CCORT).

There was significant opposition to the Highpine applications with some interveners taking the position that no sour wells should be allowed within seven kilometres of the school or the Hamlet. The risks to school students and staff from the drilling and completion of the wells were of particular concern. Other concerns focused on: the adequacy of equipment design; the adequacy of ERPs for both drilling and production; flaring; human health; the adequacy of consultation; animal health and compensation; and adverse impacts on property values.

The decision is notable for an obvious effort by the Board to provide a complete explanation of the ERCB sour well application process. The decision includes a reasonably detailed précis of the principal steps in the process including: H_2S release rate approval; determination of EPZs; public consultation; emergency response planning; application and ERCB technical review; the hearing process; and subsequent production applications. In this respect, the decision could serve as a primer on the topic.

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240 A critical sour well is one that could potentially release large quantities of hydrogen sulphide (H_2S), causing significant harm to persons in proximity. When deciding if a sour well should be considered critical, the ERCB examines factors such as the complexity of the proposed drilling, the number of residents in the relevant area, and the size of potentially affected communities. The ERCB employs two principal criteria in determining whether to classify a proposed sour well as "critical:" (i) the proximity of the well to an urban centre or public facility, such as a major recreational facility; and, (ii) the potential H_2S release rate during the drilling stage. The potential H_2S release rate is determined as a function of both the percentage of H_2S in the gas or oil and the rate at which H_2S can be delivered to the surface. *Directive 056*, *supra* note 152 at A-9, defines "critical sour well" as: "[t]he ERCB designation of a well for drilling purposes that identifies a well with an H_2S release rate of > 2.0 m^3/second or other wells with a lesser release rate in close proximity to an urban centre." See also Energy Resources Conservation Board, *EnerFAQs: Frequently Asked Questions on the Development of Alberta's Energy Resources — All About Critical Sour Wells* (Calgary: Energy Resources Conservation Board, 2009) [*EnerFAQs*].

241 *Ibid.* at 2.

242 An EPZ is "the area around a well in which full-time residents and visitors, such as campers and hunters, would be at risk in the event of a blowout. The size of an EPZ depends on the potential H_2S release rate and other specific circumstances": see *EnerFAQs*, *ibid.* at 3. An EPZ radius is ordinarily determined using the ERCB approved H_2S release rate, in accordance with ERCB *Directive 071*, *supra* note 101.

243 Parkland County is southwest of Edmonton. The Hamlet of Tomahawk is situated in the southwest portion of the County.

The ERCB was satisfied that there was ample evidence of extensive public consultation by Highpine through a variety of methods. The Board acknowledged that some interveners were not content with the consultation process and that others professed a lack of understanding of the technical information provided. The decision also recited that other interveners agreed that their concerns had been heard, but that the issues could not be resolved because of fundamental differences in the perspectives of the parties. The ERCB noted that the concerns raised were not unusual in the context of a large public consultation program and could be adequately addressed through further process and consultation, including during the public hearing (which was described as an opportunity for interveners to state their concerns and provide evidence directly to the Board).[244]

CCORT had complained that the Highpine public consultation program had been inadequate, in part because it had commenced more than two years before the public hearing was convened and therefore may not have included new residents in the area. In this regard, the ERCB noted that although new people may move into an area during a lengthy application process, a project proponent should have a reasonable expectation of closure in its pre-application process. Further, Highpine had already acknowledged the need to update its ERP to address the issue of new people moving into the area and the Board decided that updating ERPs is a reasonable way to address the issue of new arrivals within an EPZ.[245]

Parkland County had also challenged the adequacy of the Highpine public consultation efforts. However, according to the ERCB, the evidence showed that key county employees were provided with the necessary information and had ample opportunity to engage Highpine. No concerns regarding ERPs were expressed by the County until the eve of the hearing and it appeared that a change of officials had resulted in the County adopting a different position regarding the proposed wells. Highpine was found to have satisfied the consultation requirements of *Directive 056*. However, the Board noted that it sees public consultation regarding an application as the beginning of a dialogue that should continue throughout the life of the facility and urged Highpine and the community to continue to build an open and co-operative relationship.[246]

This decision is also noteworthy because of the significance of certain of the commitments that Highpine made in attempting to assuage public concerns about the safety of the children at the Tomahawk school. The Board expressed its belief that the Highpine operations could be conducted safely whether the Tomahawk school was within or outside of the drilling and completion EPZs for the wells. In particular, it accepted the Highpine evidence that considerable time could be anticipated before an emergency situation during drilling would escalate to the point that evacuation of the school would be necessary. In any event, Highpine had committed, in respect of two of the proposed wells, to avoid operations in the Nisku sour zone while the school was in session and to provide school buses and drivers on standby at the school when operations in the Nisku zone were occurring in the third well. In consideration of the concerns of the community and since these were firm commitments on Highpine's part, they were made conditions of the well licence approvals.[247]

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244 *Highpine*, *supra* note 239 at 13.
245 *Ibid.*
246 *Ibid.* at 14.
247 *Ibid.* at 23.

C. LAND MATTERS

1. *CANADIAN NATURAL RESOURCES LTD. V. BENNETT & BENNETT HOLDINGS LTD.*[248]

Bennett & Bennett Holdings Ltd. and Circle B Holdings Ltd. (collectively Bennett) are corporations engaged in the business of farming and are the owners of lands in Alberta on which CNRL holds leases. Each surface lease required CNRL to pay annual compensation to Bennett subject to the rate of compensation being reviewable every five years. In 2005, seven surface leases came up for review. CNRL attempted to negotiate new compensation rates, however, negotiations were unsuccessful and the matter proceeded to a hearing before the SRB. The SRB awarded an annual compensation increase, but not to the level requested by Bennett. The compensation award made by the SRB was appealed to the Court of Queen's Bench.

On appeal, Langston J. noted that the *Surface Rights Act* gives guidance with respect to the factors to be considered in determining the amount of compensation payable. Section 25(1) states that, in determining the amount of compensation, the Court may consider: the loss of use by the owner or occupant; any adverse effect on the remaining land of the owner or occupant; and the nuisance, inconvenience, and noise that might be caused by the operations of the operator.[249] Justice Langston noted that two approaches have developed to quantify those factors. The first is to "determine whether a standard compensation rate is being paid for land of certain types and specified uses in a generally-defined area," referred to as a pattern of dealings.[250] The second approach "attempts to calculate the actual loss of use and adverse effect that arises as a consequence of the rights granted to the operator."[251]

Justice Langston reviewed the decision in the *Intensity Resources*[252] in which Chrumka J. stated that the amount of weight to be given to a surface lease agreement entered into evidence depended on its similarity with other agreements and whether or not a pattern had been established. Justice Chrumka further listed several factors to be considered when determining whether or not a pattern of dealings had been established. Based on the factors laid out in *Intensity Resources*, Langston J. considered the critical factors in the context of the evidence provided in the case and concluded that a pattern of dealings had not been established.[253]

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248 2008 ABQB 19, 436 A.R. 256 [*Bennett*]. Leave to appeal this decision to the Alberta Court of Appeal was granted by McFadyen J.A. in *Canadian Natural Resources Limited v. Bennett & Bennett Holdings Ltd.*, 2008 ABCA 440, 75 R.P.R. (4th) 7, on the ground that the test that must be met to establish a pattern of dealings and the factors relevant to that assessment are of sufficient importance to warrant appellate consideration.

249 *Surface Rights Act, supra* note 72, s. 25(1).

250 *Bennett*, *supra* note 248 at para. 42.

251 *Ibid.* at para. 43.

252 *Intensity Resources Ltd. v. Dobish* (1989), 94 A.R. 366 (Q.B.) [*Intensity Resources*].

253 Justice Langston based this conclusion on the following factors:

> (a) There was no definition, precise or general, of the area to which this pattern was said to apply; (b) There was no information with respect to how many sites, overall, are within the area; (c) There was no indication of how many sites were reviewed in order to ascertain the comparables, nor any indication of why other sites reviewed were not comparable; (d) There was no explanation of why this pattern was applicable to a certain area; (e) There was no information provided with respect to the number of parties, either operator or landowner, represented within the comparables; (f) There was no information with respect to the negotiation process; (g) With respect to the chart showing CNRL irrigation and dryland leases, almost half of the leases do not fit the compensation pattern; (h) There was no explanation of why leases that were presented as comparables but that

Justice Langston considered the approach for assessing actual loss of use and adverse effect, which involved three steps:

> 1. In order to determine the loss of the use of the leased area, the farming practices on the land are examined in detail. Attempts are then made to quantify, on a per acre basis, the revenues which the landowner has lost as a result of the inability to use the land due to the existence of the surface lease.
>
> 2. Recognizing that the site contains an obstruction which must now be farmed around, attempts are made to quantify the effect the obstruction has on the remaining land still used by the landowner. Before this Court, this has been referred to as the "tangible portion" of adverse effect.
>
> 3. Factors such as noise emanating from a well site, or the unsightly view of a well jack from the living room window, are considered compensable factors under the *Surface Rights Act*. These and other characteristics are compensated as part of the "intangible portion" of adverse effect.[254]

Justice Langston noted that although these steps seem concise, they are more difficult to apply in practice. He found that Bennett proved adverse effects arising from the operations of CNRL, although not all of the adverse effects originally claimed.

Justice Langston found that the award for adverse effect by the SRB, although on the high side, was reasonable. The appeal was allowed in part, given the variation in awards by the SRB. Although there was a difference between the total yearly compensation calculated by Langston J. and the SRB, Langston J.'s decision provided a methodology as to how to reach the calculation, a critical segment missing from the SRB's decision.

2. *NEXEN INC. V. FARM AIR PROPERTIES INC.*, SURFACE RIGHTS BOARD DECISION NO. 2008/0182[255]

Farm Air Properties Inc. (Farm Air) applied to the SRB for review of the annual compensation payable from 18 November 2003 through 17 November 2008 for that portion of Nexen Inc.'s (Nexen) well site and access road situated within its lands in northeast Calgary. The application was made pursuant to s. 27, or alternatively s. 29, of the *Surface Rights Act*.

Farm Air argued that Nexen's well site constrained the residential development of its lands, which should be compensated under s. 27. Farm Air presented three bases for compensation: (1) reduction in the available area that could be sold as lots due to design inefficiencies resulting from the presence of the well site; (2) losses from the delay of development due to discovery of contamination and the attendant remediation; and (3) additional costs resulting from design changes arising from the discovery of contamination

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did not fit the compensation pattern supported the pattern of dealings; and (i) There was no explanation as to why initially only new agreements were considered appropriate comparables, but why later, rent reviews were also considered to be properly included.

Ibid. at para. 88.

254 *Ibid.* at para. 90.

255 *Nexen Inc. v. Farm Air Properties Inc.* (10 July 2008), SRB Decision No. 2008/0182, online: SRB <http://www.surfacerights.gov.ab.ca> [*Nexen*].

and the required remediation.[256] The aggregate amount claimed by Farm Air was approximately $3,200,000.

Farm Air took the position that s. 27 of the *Surface Rights Act* should be given a broad and liberal interpretation in accordance with the Supreme Court of Canada decision in *Dell Holdings*.[257] Although the decision in *Dell Holdings* dealt with land expropriation for public purposes in Ontario, Farm Air argued that its principles should extend to the interpretation of the *Surface Rights Act* to the extent that it constitutes expropriation legislation. Farm Air argued alternatively that, if the SRB determined that its claims were not within the scope of s. 27 under which annual rates of compensation payable under a surface lease or right of entry compensation order are reviewable every five years, the SRB had jurisdiction to grant the compensation under s. 29(b), which allows the SRB to "review, rescind, amend or replace a decision or order made by it."[258]

Nexen argued that s. 27 of the *Surface Rights Act* is intended to provide a review of recurring or continuing losses, whereas the majority of the claims advanced by Farm Air were "one time events."[259] Nexen further argued that any claim arising from impacts associated with off-site contamination should be made under s. 30 of the *Surface Rights Act*, which provides the SRB jurisdiction to award compensation for "damage caused by or arising out of the operations of the operator to any land of the owner or occupant other than the area granted to the operator"[260] subject to a limit of $25,000. As for Farm Air's reliance on s. 29 of the *Surface Rights Act*, Nexen argued that Farm Air had not satisfied the procedural requirements for initiating such a request under the *Surface Rights Act Rules of Procedure and Practice*,[261] which requires a party to provide reasons for requesting a review, rescission, or amendment.

In regard to Farm Air's argument about the affect of the design inefficiencies, the SRB disallowed Farm Air's claim in its entirety. In general, the SRB found that Farm Air purchased the lands knowing of the development constraints imposed by the well, and therefore could not now claim compensation.[262]

In considering Farm Air's claim for loss of use and adverse effect, the SRB did not accept Nexen's argument that compensation for contamination that extended to off-site areas could only be claimed under s. 30 of the *Surface Rights Act*. At the same time, the SRB rejected Farm Air's valuation method for loss of use and adverse effects based on deferred profits. Instead, it adopted Nexen's analysis based on a return on land value, which was essentially confined to the footprint of the well site, access road, and a small surrounding area.

The SRB also did not accept Nexen's position that the award for the last year in the review period should be pro-rated if the reclamation certificate for the well site and access road was

256 *Ibid.* at 5.
257 *Toronto Area Transit Operating Authority v. Dell Holdings Ltd.*, [1997] 1 S.C.R. 32 [*Dell Holdings*].
258 *Surface Rights Act*, *supra* note 72, s. 29(b).
259 *Nexen*, *supra* note 255 at 6.
260 *Surface Rights Act*, *supra* note 72, s. 30(1)(a).
261 Alta. Reg. 196/2007, s. 10(1).
262 *Nexen*, *supra* note 255 at 13.

issued in advance of the 17 November 2008 anniversary.[263] The SRB awarded an aggregate amount of $515,500 for these losses over the five-year review period.

Having concluded that the SRB could consider Farm Air's claims arising from the contamination, the SRB partially allowed Farm Air's claim for added engineering and planning costs as a result of having to modify its development applications and for costs of consultation with regulatory authorities in connection with the contamination. However, the SRB discounted Farm Air's claim by one third, resulting in compensation amounting to $188,000.

D. EMERGENCY RESPONSE PLANNING

One of the most significant developments in emergency response planning over the past year has been the final amendments made to *Directive 071*. These most recent amendments, made in November 2008, were not substantive and reflect clarifications based on feedback received from various stakeholders. A more detailed overview of *Directive 071* is found in Part II.F.1, above.

1. ERCB ENHANCED MUTUAL AID FOR OIL AND GAS INCIDENT RESPONSE IN THE PEMBINA AREA

In March 2008, the ERCB became involved in a 12-month pilot project in the Pembina area of Alberta to develop a "more robust incident and emergency response to oil and gas events through an enhanced and formalized mutual aid group" for the Pembina area.[264] This initiative was undertaken due to the large volume of overlapping emergency planning zones and the wide variety of operator ERPs in that area. A multi-stakeholder committee was first struck to discuss these issues in 2006.

Throughout the one-year pilot project, ERCB staff were directed to work with stakeholders, including operators, residents, municipal representatives, and other industry representatives, to investigate how best to undertake an ERP in the area. The commitment undertaken by the ERCB was limited to participation and the provision of expertise as opposed to financial contributions. The committee that worked on the pilot project made several recommendations to improve ERPs in the Pembina area; many of these recommendations were reflected in the changes made to *Directive 071*.

E. FLARING, INCINERATING, AND VENTING

According to the World Bank Global Gas Flaring Reduction Partnership (GGFR), the equivalent of the annual gas consumption of France and Germany combined is flared around the world every year; globally this has not abated over the past 20 years.[265]

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263 *Ibid.* at 16.

264 Energy Resources Conservation Board, *Bulletin 2008-14: Enhanced Mutual Aid for Oil and Gas Incident Response in the Pembina Area* (Calgary: Energy Resources Conservation Board, 2008) at 1.

265 National Energy Board *et al.*, *World Bank Global Gas Flaring Reduction — Private Public Partnership Implementation Plan for Canadian Regulatory Authorities* (June 2008) at 2, online: World Bank <http://sitesources.worldbank.org/EXTGGFR/Resources/canada_cip.pdf?resourceurlname=canada_cip.pdf>. See also "EUB Releases Flaring and Venting Report: Solution Gas Flaring Down 70%, Solution

Concerned about the negative impact of these practices, the GGFR developed the Voluntary Standard for Global Gas Flaring and Venting Reduction (the GGFR Standard) in 2006 to encourage member parties to work together to share best practices and seek solutions to conserve resources and minimize the global environmental issues presented by flaring. As at June of 2008, the majority of Canadian regulatory authorities, representing 99 percent of Canada's oil and gas production, had formally endorsed the GGFR Standard.[266]

In September of 2008, the GGFR released its *Guidelines on Flare and Vent Measurement*,[267] the next major step in standardization.

1. *DIRECTIVE 017: MEASUREMENT REQUIREMENTS FOR UPSTREAM OIL AND GAS OPERATIONS*

On 22 October 2009, the ERCB published a revised version of *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations*.[268] This directive defines the standards for the measurement of fluid production and the disposition associated with upstream petroleum operations. Several sections have been updated or clarified including the general requirements for liquid meters and for condensate delivered to gas fractionation plants. More substantively, a section on "Trucked Liquid Measurement" was added to provide requirements for trucked liquid that is measured and brought from oil and gas production facilities to either another facility or out for sale. A full section regarding "Acid Gas and Sulphur Measurement" was also added to the 2008 edition. This section deals with the measurement and base requirements for the acid gas and sulphur that is generated through the processing of sour gas into saleable, pipeline quality gas.

2. BRITISH COLUMBIA OIL AND GAS COMMISSION FLARING, INCINERATING, AND VENTING REDUCTION GUIDELINES

In February 2008, the British Columbia Oil and Gas Commission (BCOGC) released its revised *Flaring, Incinerating and Venting Reduction Guideline for British Columbia*[269] to bring its regulatory requirements more in line with the GGFR Standard. This guideline adopted many provisions from the ERCB's *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*,[270] with major amendments focused on changes to the application process and requirements for notification and reporting. The BCOGC has stated

Gas Venting Down 38%" *Across the Board* (May 2004) 3.

266 Canadian regulatory bodies that have endorsed the Standard include the: National Energy Board; British Columbia Oil and Gas Commission; ERCB; Saskatchewan Ministry of Energy and Resources; Manitoba Science, Technology, Energy and Mines; Canada-Newfoundland and Labrador Offshore Petroleum Board; and the Newfoundland and Labrador Department of Natural Resources.

267 Clearstone Engineering Ltd., *Technical Report: Guidelines on Flare and Vent Management* (Calgary: Global Gas Flaring Reduction Partnership, 2008).

268 Energy Resources Conservation Board, *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations* (Calgary: Energy Resources Conservation Board, 2009). For the purposes of this directive, "measurement" includes measurement, accounting, and reporting.

269 Oil and Gas Commission, *Flaring, Incinerating and Venting Reduction Guideline for British Columbia* (Fort St. John: Oil and Gas Commission, 2008) [*Reduction Guideline*].

270 Energy Utilities Board, *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* (Calgary: Energy Utilities Board, 2006).

that it is seeking to eliminate flaring of all routine associated gas (gas that meets an economic threshold for conservation) by 2016.[271]

3. NEWFOUNDLAND AND LABRADOR DEPARTMENT OF NATURAL RESOURCES

Newfoundland and Labrador Department of Natural Resources (Nfld NR) has stated that it is also working to develop guidelines that will draw from the work done by the GGFR and *Directive 060*.[272]

F. ABANDONMENT

1. *DIRECTIVE 072: WELL ABANDONMENT NOTIFICATION REQUIREMENTS*

In December 2008, the ERCB released *Directive 072: Well Abandonment Notification Requirements*.[273] The directive became effective on 5 January 2009 and requires that notification be given to the ERCB via its Digital Data Submission System prior to any routine or non-routine cased or open-hole well abandonment.

For cased-hole abandonments, notification must be submitted at least 24 hours prior to commencement of operations. For open-hole abandonments, notification must be submitted as soon as a decision has been made to abandon the well following a geological evaluation.[274] Oil sands evaluation wells and test hole wells drilled within the surface mineable area are exempt from this requirement. Prior to *Directive 072*, notification had been discretionary on the part of operators. Failure to provide notification may be subject to "Low Risk enforcement" in accordance with *Directive 019*.[275]

2. *DIRECTIVE 024: LARGE FACILITY LIABILITY MANAGEMENT PROGRAM*

A revised version of *Directive 024* was released in October of 2008 to replace the 2005 edition.[276] The Large Facility Liability Management Program (LFP) deals with the assessment of licensee abandonment and reclamation liability associated with large upstream oil and gas facilities. The intent behind the LFP is to prevent the public from bearing "the costs to suspend, abandon, remediate, and reclaim a facility" should a licensee become defunct.[277] The revised edition eliminates the phase-in provisions contained in the 2005 edition and removes the appendices addressing the generic ERCB security deposit provisions, which are now contained in *Directive 068*. The 2008 edition has also eliminated its enforcement provisions, which are now contained in the larger *Directive 019*. It is anticipated that this directive will undergo further review over the next three to five years.

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271 *Reduction Guideline*, *supra* note 269 at 2.
272 *Ibid.* at 18.
273 Energy Resources Conservation Board, *Directive 072: Well Abandonment Notification Requirements* (Calgary: Energy Resources Conservation Board, 2008) [*Directive 072*].
274 An open-hole abandonment is defined as the "downhole abandonment of a well after drilling is complete but before the rig is released," i.e., before all drilling operations are completed. A cased-hole abandonment is the "downhole abandonment of a completed or cased well": *ibid.* at 1.
275 *Ibid.*
276 *Directive 024, supra* note 211.
277 *Ibid.* at 2.

3. BCOGC INFORMATION LETTER OGC 09-06, "PIPELINE DEACTIVATION AND ABANDONMENT PROCESS"

On 19 February 2009, the BCOGC issued Information Letter OGC 09-06: "Pipeline Deactivation and Abandonment Process,"[278] which was developed in consultation with landowners and the CAPP. The revised process requires companies to, among other things, deactivate, abandon, or return to active service a pipeline that has not been in active flowing service for a period of 12 months. An action plan may also be required detailing the company's future intentions. Details surrounding the procedures for the planned deactivation of a pipeline are also set out.

G. RESOURCES MATTERS: OWNERSHIP

1. ERCB *BULLETIN 2008-50: PROCESSING OF APPLICATIONS FOR COAL BED METHANE DEVELOPMENT*[279]

The ERCB issued this bulletin regarding applications for Coalbed Methane (CBM) development on 24 December 2008. The ERCB continues to receive applications for well licensing, compulsory pooling, and holding orders from coal holders who take issue with the Board's ruling in *Bearspaw Petroleum*[280] regarding entitlement to CBM for regulatory purposes. The ERCB noted that, in *Bearspaw Petroleum*, the AEUB considered a number of applications for well licences, compulsory pooling orders, and holding orders submitted by Bearspaw Petroleum Ltd., Devon Canada Corporation, and Fairborne Energy Ltd. In that decision, the AEUB determined that natural gas holders, as opposed to coal holders, were entitled to the CBM for AEUB regulatory purposes. Certain coal holders who disagreed with this decision appealed it to the Court of Appeal. The appellants discontinued those appeals and *Bearspaw Petroleum* stands. Therefore, the ERCB considers it to be the definitive position in Alberta in respect of CBM entitlement for ERCB regulatory purposes.

The ERCB decided to revisit its approach to applications subject to objections by coal holders. The ERCB noted that coal holders need to be notified of these applications, but found that continued objections that did not differ in any material way from the conclusions in *Bearspaw Petroleum* and the subsequent processing of such applications as non-routine was administratively inefficient and burdensome.

The ERCB announced that, effective 1 January 2009, applicants for well licensing, compulsory pooling, and holding orders and any other applications relating to gas or CBM development may file routinely following the required notification of the coal owner(s) and any other potentially affected party, provided that: "(1) filers of CBM objections do not raise any new or unique concerns or claims that do not relate to CBM entitlement based on coal

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278 Oil and Gas Commission, Information Letter OGC 09-06, "Pipeline Deactiviation and Abandonment Process" (19 February 2009).

279 Energy Resources Conservation Board, *Bulletin 2008-50: Processing of Applications for Coalbed Methane Development* (Calgary: Energy Resources Conservation Board, 2008).

280 *Bearspaw Petroleum Ltd., Devon Canada Corporation, and Fairborne Energy Ltd.* (28 March 2007), EUB Decision 2007-024, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-024.pdf> [*Bearspaw Petroleum*].

ownership and/or trespass or potential damage to the coal resulting from gas or CBM production; and (2) no other parties object to the application."[281]

H. RESOURCES MATTERS: SPACING

1. ERCB DECISION 2008-115: *ENCANA CORPORATION: APPLICATION FOR SPECIAL GAS WELL SPACING — LAWRENCE FIELD*[282]

In August 2008, the ERCB held a hearing on an application made by EnCana for the establishment of a holding and the corresponding suspension of the drilling spacing unit (DSU) and target area provisions over seven sections within the Lawrence Field. The holding proposed by EnCana would have a maximum of two wells per pool per section and a buffer zone of 200 metres for each producing well.

Ignition Energy Inc. (Ignition), a mineral interest owner in the sections immediately offsetting the proposed holding, filed an objection on the basis that the available production data did not justify either down spacing to two wells per pool per section or a relaxation of the buffer zones.

As approval of the requested holding would create the equivalent of a reduced gas well spacing, EnCana had to satisfy at least one of the requirements of s. 4.040(3) of the *Oil and Gas Conservation Regulations*[283] regarding increased recovery, as well as satisfying the Board that no unacceptable inequity would result from the holding.

In its decision, the Board set out its primary criteria for reviewing the application as: (1) determination of the reservoir quality; (2) continuity of the applied-for gas pay zones; (3) the potential to encounter incremental reserves; and (4) what ought to be recognized as gas pay.[284] The ERCB considered each of these criteria in turn and ultimately satisfied itself that the additional wells proposed would improve recovery and drain the gas pay at a reasonable rate that would not adversely affect recovery.

In regards to potential inequities, the ERCB rejected Ignition's submissions that the applied for holding would result in an inequitable drainage. Rather, the Board confirmed that the core data and evidence provided by EnCana regarding the need for fracturing to obtain commercial production would suggest that the reservoirs in the applied for area were discontinuous and of poor quality.

Further, on the equity issue, there was no evidence presented that Ignition had proven reserves or a capable well on its lands. For this reason, the Board also rejected Ignition's submission that the buffer zone should be increased to 300 metres. Lastly, EnCana argued,

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281 *Ibid.* at 2.

282 *EnCana Corporation: Application for Special Gas Well Spacing — Lawrence Field* (25 November 2008), ERCB Decision 2008-115, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2008/2008-115.pdf> [*EnCana Well Spacing*].

283 Alta. Reg. 151/71 [*OGCR*].

284 *EnCana Well Spacing*, *supra* note 282 at 11.

and the Board accepted, that Ignition would not be prevented from similarly applying for a reduced spacing unit on its lands.

EnCana did not provide evidence that incremental reserves would be recovered from two of the zones applied for in the holding and, as such, these zones were excluded from the approval for reduced spacing. Reduced spacing on the remaining zones however, was determined to result in improved gas recovery; on this basis, the Board found that additional wells were needed to drain the pool at a reasonable rate.[285]

2. ERCB WELL SPACING INITIATIVE

Throughout 2008, the ERCB continued to work with interested stakeholders to design and implement the next phase of its Well Spacing Initiative. Past steps in the Initiative include: the creation of a regional area for higher baseline well spacing in parts of Eastern Alberta, revisions to the notification requirements for well spacing applications, and the development of a GIS-spacing database. The next stage in the Initiative is more process-based and entails the design and development of a new well spacing electronic application form with associated processing pathways and revised application requirements.[286] Toward that end, in April 2008, the ERCB Well Spacing Team met with an industry focus group to review, among other things, the new electronic forms and the associated application requirements. The Industry Focus Group was generally quite positive in its feedback and, in 2009, will begin conducting software testing of the new systems.

3. BCOGC INFORMATION LETTER OGC 08-20, "SUBMISSION REQUIREMENTS FOR MULTI-WELL PADS AND WELL-TO-WELL SPACING"[287]

In December 2006, the BCOGC released the revised *Oil and Gas Commission Planning and Construction Guide*[288] setting out certain specifications for wellbores on multi-well pads containing close well spacing (defined as 25 metres or less).

Due to an increased number of these wellbore applications, the Commission decided to streamline the application process and revise the operational requirements. Information Letter OCG 08-20, published by the BCOGC on 17 October 2008, will guide application submissions until such time as the Guide can be officially updated.

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285 *Ibid.*
286 "Current Projects: Well Spacing Initiative," online: ERCB <http://www.ercb.ca/>.
287 Oil and Gas Commission, Information Letter OGC 08-20, "Submission Requirements for Multi-Well Pads and Well-to-Well Spacing" (17 October 2008) [Information Letter OGC 08-20].
288 Oil and Gas Commission, *Oil and Gas Commission Planning and Construction Guide: For Oil and Gas Operations in British Columbia* (Fort St. John: Oil and Gas Commission, 2006).

I. RESOURCES MATTERS: POOLING

1. ERCB DECISION 2008-080: *RESPONSE ENERGY CORPORATION APPLICATION FOR COMPULSORY POOLING — KAKWA FIELD AND PARAMOUNT RESOURCES LTD. APPLICATION FOR SPECIAL GAS WELL SPACING — KAKWA FIELD*[289]

On 2 September 2008, the ERCB released this decision approving the application of Response Energy Corporation (Response) for a compulsory pooling order and denying the application of Paramount Resources Ltd. (Paramount) for special gas well spacing.

By way of background, Response and Paramount each held mineral interests in section 22 of the Kakwa Field. Since 2004, Paramount has been the largest working interest owner in the north half of section 22 and is currently the licensee of the 13-22 well (which, aside from test production, had never produced). Response purchased the petroleum and natural gas rights in the south half of section 22 in 2006. Shortly thereafter, Paramount initiated discussions with Response about pooling the DSU. Those negotiations ultimately failed, leading to the within applications.

In its application, Response sought an order stipulating that all tracts within the DSU constituting section 22 be operated as a unit for the production of gas from certain zones, through the 13-22 well. Response also requested, among other things, that costs and revenues under the compulsory pooling order be allocated on a tract area basis and that Response be named as operator.

Paramount, in contrast, applied for an order prescribing half-section drilling spacing units (separated between the south and north), with a 200-metre buffer zone from, and parallel to, the sides of each of the DSUs.

The three issues set out and considered by the Board in these applications were: (1) the need for a reduced gas well spacing and whether it would result in unacceptable inequity; (2) the need for the pooling order; and (3) the specific provisions of the pooling order.[290]

On Paramount's application, the Board noted that there was insufficient information to assess the potential conservation and equity aspects of the proposed changes to section 22, as there was limited data from the area. Further, the data that was available on the drainage areas was dated and inconclusive, having been taken from initial well tests conducted in 1980, model forecasts of production, and decline analysis of a few analog wells. The Board found that the evidence was insufficient to accept that reduced spacing and the corresponding "separation in equity" would be the appropriate recovery strategy.[291]

289 *Response Energy Corporation: Application for Complusory Pooling — Kakwa Field and Paramount Resources Ltd.: Applicatoin for Special Gas Well Spacing — Kakwa Field* (2 September 2008), ERCB Decision 2008-080, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2008/ 2008-080.pdf>.

290 *Ibid.* at 5.

291 *Ibid.* at 8.

Virtually no analysis was undertaken regarding the compulsory pooling order; rather, the Board merely made note of the fact that the parties had previously attempted to reach an agreement on pooling but had reached an impasse on issues surrounding the appropriate methodology to account for the equalization of drilling costs for the 13-22 well.

As the parties conceded that the reservoir properties were unknown, the examiners recommended that production be allocated on a tract ownership basis (50 percent of production would be allocated to mineral owners in each of the north and south half of section 22). As Paramount was the licensee of the 13-22 well, it was to be designated operator; the Board found that no evidence was tendered to suggest that it should deviate from its normal practice in this regard.

Finally, the ERCB looked at the overarching principles typically relied upon in setting drilling costs namely: (1) an equalization of wellbore costs is undertaken to reimburse parties for any expenses incurred in drilling; and (2) original parties that took the exploration risk are recognized.[292] The Board traced the original drilling costs for the 13-22 well, set at $1,919,949 and ordered Response to pay its 50 percent proportionate share of this amount.

J. RESOURCES MATTERS: CO-MINGLING

1. ERCB FORMATION AND POOL CODING PROJECT

The Formation and Pool Coding Project was initiated in April 2008 "to revise the conventions used to assign codes and names to administrative pools (i.e. commingled, multifield, coalbed methane, and shale gas pools)."[293] The process was instituted due to a realization that the existing convention resulted in pool codes and names that were inconsistent, cryptic, non-descriptive, and challenging to work with. On 20 February 2009, the project phase to rename and recode the majority of commingled gas pools in Alberta was completed. The re-codification process for the remaining pools in the SE Alberta Gas System (all gas pools south of township 31 and east of the 5th meridian) resumed in April 2009 and was completed in August 2009.[294]

K. RESOURCES MATTERS: POOL DELINEATION

1. ERCB DECISION 2009-024: *CANADIAN NATURAL RESOURCES LIMITED APPLICATION FOR POOL DELINEATION AND GAS SHUT-IN — ATHABASCA WABISKAW-MCMURRAY*[295]

On 24 February 2009, the ERCB approved CNRL's application for a pool delineation order to include the Wabiskaw interval in the well at 12-28-73-8W4M (the 12-28 well) in the Kirby Upper Mannville U2U Pool (U2U pool), and for an order to shut in gas production

292 *Ibid.* at 13.
293 "Current Projects: Formation and Pool Coding Project," online: ERCB <http://www.ercb.ca>.
294 *Ibid.*
295 *Canadian Natural Resources Limited: Application for Pool Delineation and Gas Shut-in — Athabasca Wabiskaw-McMurray* (24 February 2009), ERCB Decision 2009-024, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2009/2009-024.pdf>.

from the Wabiskaw interval. The ERCB rescinded the existing pooling order for the single well, Kirby Upper Mannville RR Pool.

CNRL's application was based on concern regarding production from the Wabiskaw interval in 12-28 well because the interval directly offset an area in which CNRL had applied to the ERCB to develop a thermal bitumen recovery scheme. CNRL also highlighted a potential equity issue of gas being produced from the U2U pool by the 12-28 well, while the rest of the wells in the pool, some of which were owned by CNRL, were shut in by ERCB order.

CNRL submitted that the Wabiskaw interval in the 12-28 well had been incorrectly designated as a single-well pool as a result of an error in determining the ground elevation for the well. CNRL submitted evidence that the Wabiskaw interval in the 12-28 well was in the same stratigraphic unit as the Wabiskaw intervals in the surrounding U2U pool wells, such that the Wabiskaw interval in the 12-28 well was part of the U2U pool.

Enerplus Resources Fund (Enerplus) intervened in support of CNRL's application. As owner of the oil sands rights in Section 28-73-8W4M and several surrounding sections, it was concerned that gas production from the Wabiskaw interval in the 12-28 well was affecting bitumen recovery options. Enerplus requested that, as part of the application process, ISH Energy Ltd. (ISH), the sole working interest holder of the well, be required to obtain a current reservoir pressure at its 12-28 well to confirm the level of pressure depletion and to assist with appropriate resource development planning. If this could be accomplished without a hearing, Enerplus was in favour of proceeding without a hearing.

Initially ISH, as the sole working interest owner of the 12-28 well, objected to CNRL's application. Moreover, ISH acquired a new ground elevation measurement that was close to CNRL's estimate. ISH maintained that pressure data was the most effective means of delineating pools and submitted that the variation in currently available pressure data suggested that the U2U pool was made up of several smaller pools. ISH acknowledged that, considering the new ground elevation information, the 12-28 well could be in communication with the U2U pool and should therefore remain shut in.

The ERCB determined that, given the new ground elevation information, the "12-28 well fits structurally with the Wabiskaw intervals in the offsetting wells in the U2U Pool."[296] Considering the close proximity of the 12-28 well to the zero edge of the U2U pool, the ERCB concluded that the Wabiskaw interval in the 12-28 well should be placed in the U2U pool. It therefore determined that a shut-in order should be issued for the interval to be consistent with the existing shut-in order for the U2U pool protecting bitumen. Since gas production was shut-in, the ERCB did not see a compelling reason to require ISH to obtain a pressure measurement. The ERCB concluded that there was no need for a hearing.[297]

296 *Ibid.* at 3.
297 *Ibid.*

2. ERCB DECISION 2008-130: *HUNT OIL COMPANY OF CANADA INC.: APPLICATIONS TO AMEND ENHANCED RECOVERY SCHEME APPROVAL NO. 10848 AND POOL DELINEATION — KLESKUN AND PUSKWASKAU FIELDS*[298]

On 23 December 2008, the ERCB issued its decision in an application by Hunt Oil Company of Canada, Inc. (Hunt) pursuant to ss. 39(1)(a) and 33 of the *Oil and Gas Conservation Act*[299] to amend its enhanced recovery scheme for the Kleskun Beaverhill Lake A Pool (the A Pool) and to include wells now in the Puskwaskau Beaverhill Lake C Pool (the C Pool) in the A Pool. Galleon Energy Inc. (Galleon), a licensee of wells in the A Pool, filed an objection to the first application.

The A Pool is a conventional oil pool and is being competitively operated with two separate waterflood schemes, one operated by Galleon and the other by Hunt. The ERCB considered the issues respecting the applications to be: "(1) pool delineation; (2) the need for and location of additional injectors in Hunt's waterflood scheme; and (3) the potential for Hunt's proposed injectors to negatively affect Galleon's producers."[300]

Hunt applied to have four wells from the C Pool added to the northeast of the A pool based on pressure communication between the wells and the A Pool. Galleon did not object to Hunt's application to have the four wells added to the A Pool, but argued that three wells in the southwest edge of the A Pool were also in the pool. Hunt submitted that these three wells were not within the A Pool based on poor pressure communication and Hunt's interpretation of the oil-water contacts for those wells.

The examiners agreed that the four wells were part of an expanded A Pool, but did not recommend a pooling change for the three southwest wells as neither party requested such a change.[301]

Hunt and Galleon agreed that additional water injection was required in the expanded A Pool, but had different views as to how to optimize recovery. Both companies created reservoir simulations to evaluate the effect of additional injectors. Hunt argued that the results of their model supported its proposed injector locations, which were in the central part and north edge of the A Pool. Based on its model, Galleon advocated a different approach, using only injectors closer to the edges of the A Pool.

The ERCB agreed with both parties that "additional water injection is needed in the part of the A Pool operated by Hunt in order to optimize oil recovery."[302] In regard to the reservoir simulations used by both parties, the ERCB recognized that although reservoir simulation was a useful tool in assessing the merits of injector locations, it was not possible to test the ability of the models to predict water production as there was little water production data available for the A Pool. The ERCB found that Hunt's model was better able

298 *Hunt Oil Company of Canada, Inc.: Applications to Amend Enhanced Recovery Scheme Approval No. 10848 and Pool Delineation — Kleskun and Puskwaskau Fields* (23 December 2008), ERCB Decision 2008-130, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2008/2008-130.pdf> [*Hunt*].
299 R.S.A. 2000, c. O-6 [*OGCA*].
300 *Hunt*, *supra* note 298 at 4.
301 *Ibid.* at 6.
302 *Ibid.* at 12.

to match available data and overall they had more confidence in the predictions from Hunt's model than from Galleon's model.[303]

The ERCB also noted other issues with Galleon's proposed waterflood including that Galleon's proposed injectors were located in lower quality rock, which raised concerns about attaining adequate water injectivity. Further, the ERCB noted that Galleon's proposal involved converting all the producing wells in one section to injectors, which would result in any displaced oil in that section having to be swept a long distance over the reservoir to be captured by producers.[304] As a result, the ERCB concluded that Hunt's proposed approach to waterflooding was preferred.

The ERCB then considered the effect the proposal would have on Galleon. Galleon had identified two concerns regarding Hunt's proposed injectors: (1) "reduced sweep efficiency by injecting into updip wells in a reservoir where there is an oil-water contact and likely contact with an aquifer"; and (2) "the possibility for premature water breakthrough because of high-permeability channels in the A Pool."[305]

In regard to concerns about reduced sweep efficiency, Galleon acknowledged during cross-examination that its own model indicated that updip injection would not be as harmful as Galleon had initially claimed. Since neither the Hunt nor Galleon models predicted an adverse effect due to updip injection, the ERCB concluded that updip injection was not a major concern.[306]

In regard to concerns about premature water breakthrough, the ERCB acknowledged that water will eventually break through to producers in any waterflood, but this water breakthrough would not necessarily be premature. The ERCB agreed with Hunt's definition of premature water breakthrough as being that which "occurs when water arrives at a producer without displacing a mobile oil bank in front of the injected water."[307] The ERCB noted that neither the Hunt nor the Galleon models predicted premature water breakthrough. In the absence of further evidence of premature water breakthrough, the ERCB was not convinced that there was sufficient reason to justify denying Hunt's application.

L. RESOURCES MATTERS: COMMON CARRIER ORDERS

1. ERCB DECISION 2009–013: *TYKEWEST LIMITED APPLICATION FOR A COMMON CARRIER ORDER — KNOPCIK FIELD*[308]

TykeWest Limited (TykeWest) applied to the ERCB for an order declaring New North Resources Ltd. (New North) as a common carrier of gas from the "JJ Pool" through its pipeline located in Western Alberta. TykeWest also applied: (1) "to designate the 3-16 tie-in

303 *Ibid.* at 13.
304 *Ibid.* at 13-14.
305 *Ibid.* at 15.
306 *Ibid.* at 19.
307 *Ibid.*
308 *TykeWest Limited: Application for a Common Carrier Order — Knopcik Field* (10 February 2009), ERCB Decision 2009-013, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2009/2009-013.pdf> [*TykeWest*].

location as the point at which the common carrier would take delivery of the gas to be transported under the common carrier order," and (2) "for an order to direct the proportion of production to be taken by the common carrier from each producer or owner in the subject pool."[309] New North objected to the application.

New North and TykeWest had working interests in a common well, the gas from which was transported by a gathering line owned by New North, New Range, and TykeWest (the Gathering Line) to a blending facility and then on to EnCana's gathering system. There was a contractual dispute between the parties regarding the well and associated facilities, which was being litigated at the time of the application. In August 2007, TykeWest drilled another well 715 metres north of the joint well which was not tied into the gathering system. The parties agreed that both wells were in the JJ Pool.

New North argued that the "Subparticipation Agreement" (through which the parties earned their interest in the joint lands) incorporated the *1990 CAPL Operating Procedure*[310] and gave priority to jointly owned gas. It followed that TykeWest had contractually obligated itself to back out any of its non-jointly owned gas, if necessary. New North urged the Board not to issue a common carrier order because of the contract between the parties and the fact that an order would restrict production rates dramatically for both wells, possibly to the point where neither well could be produced economically.[311]

TykeWest argued that the contract pertaining to the jointly owned well was not relevant and that an order offered the only reasonable solution to transport stranded production from its well.

The Board noted that the one of the purposes of the *OGCA* was to ensure each owner the opportunity to obtain its share of production and to permit the economical, orderly, and efficient development of Alberta's oil and gas resources. While the Board accepted prior rulings that established a general rule that a common carrier order should not override a contract between the parties, it held that the present agreement did not adequately address the matter, or the issue of drainage. The Board held that a common carrier order was the most practical and environmentally sound option for transporting the gas, as it would avoid a proliferation of sour gas facilities and could address the drainage issue in a timely manner. Finally, the Board noted that, contrary to the position of New North, the relevant legislation did not compel an applicant for a common carrier order to demonstrate that spare capacity was available on the pipeline.[312]

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309 *Ibid.* at 3.
310 *1990 CAPL Operating Procedure* (Calgary: Canadian Association of Petroleum Landmen, 1990).
311 *TykeWest*, *supra* note 308 at 9.
312 *Ibid.* at 10.

V. CLIMATE CHANGE

A. CO_2 REGULATION

1. *CLIMATE CHANGE AND EMISSIONS MANAGEMENT ACT*

In 2007, the Alberta government introduced climate change legislation, the first jurisdiction in North America to promulgate a statute on the topic.[313] A couple of articles from the 2007-2008 CPLF Conference described the characteristics of the legislation,[314] the fundamentals of which include a focus on emission intensity. By way of brief recap, this statutory scheme focuses on the amount of CO_2 emissions per unit of production with reference to the baseline emissions intensity for a given industrial operation. Compliance mechanisms include emissions performance credits, contributions to the climate change and emissions management fund and a built-in offset system for acquiring credits. Emission performance credits are earned by a governed facility when its emissions per unit of production are under the established baseline. Unused performance credits can be banked or traded. Payments to the fund can be made in the case of a failure to meet emission standards on the basis of a simple cash for compliance payment. The offset system also affords trading opportunities where government approved offsets are unused.

2. FEDERAL INITIATIVES

The details of Canada's proposed GHG regime have not been finalized, although the federal government has issued various policy statements. As at the March 2008 update,[315] various legal details remained unstated. Up until that point in time, the federal government had been proceeding along the lines of the Alberta scheme with a focus on emissions intensity, although with different thresholds for emissions and reductions. This focus on emissions trading may soon change however, as the new Obama administration in the U.S. has released budget figures estimating that US$645 billion in revenue will be generated from the auction of allocated carbon credits under a cap and trade system, to be established between 2012 and 2019. The Canadian government has indicated that Canada may be prepared to move away from an emissions intensity regime towards a joint North American cap and trade regime.[316]

Some have been critical of the federal government's apparent willingness to approach GHG emissions from the standpoint of intensity.[317] Intensity targets, which focus on emissions per unit of production inherently accept economic growth and increased production. Thus, an emitter that adds a new train to an existing GHG regulated facility

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313 *CCEMA*, *supra* note 179; *Specified Gas Emitters Regulation*, Alta. Reg. 139/2007; *Specified Gas Reporting Regulation*, Alta. Reg. 251/2004; *Administrative Penalty Regulation*, Alta. Reg. 140/2007.

314 Lowe & Liteplo, *supra* note 156; see also: Goetz *et al.*, *supra* note 156.

315 Canada, *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions* (Ottawa: Environment Canada, 2008).

316 Dufferin Harper, Matt Flynn & Adam Garrett, "The Role of Emissions Offset Trading in North American Greenhouse Gas (GHG) Emissions Regimes" *Blakes Bulletin* (24 March 2009), online: Blake, Cassels & Graydon LLP <http://www.blakes.com/english/legal_updates/cleantech/mar_2009/EmissionsOffsetTrading.pdf>.

317 See e.g. Clare Demerse & Matthew Bramley, *Backgrounder: The March 2008 Federal Regulatory Framework for Industrial Greenhouse Gas Emissions* (Calgary: The Pembina Institute, 2008).

might improve its efficiency per unit of production, but still increase the overall number of units of production. The emitter will be in compliance with the legislation while at the same time increasing overall emission of GHGs. Critics argue that this system is problematic, as the methodology puts no upper limit on overall GHG emissions. In contrast, a cap and trade system is predicated on an absolute cap on GHG emissions within a set period of time. If the cap is exceeded, the emitter is offside the regime and must avail itself of trading options or the other mandated methodologies to bring itself within compliance.

Given these developments and those discussed below, it remains uncertain what direction Canada will ultimately move. While on the one hand, the Alberta-type scheme of emissions intensity seems to have motivated the Canadian government in terms of its past policy statements, uncertainty has been created by the more recent apparent willingness of the federal government to align itself with a cap and trade system, perhaps on an overall North American basis.

Regardless of how the turbulence in the GHG realm is ultimately resolved, it seems likely that emissions trading will be a reality for Canadian industry, and the petroleum industry in particular. Whether under a cap and trade regime or an emission intensity regime, compliance trading will be (many would say already is) a reality.

Emitters involved in an offset trading system can meet their emissions obligations or otherwise reduce their carbon footprint by purchasing GHG emissions offset credits. These tradeable credits are created when an entity that emits less GHGs than the emissions threshold produces a product in a manner that releases less GHG than the baseline case. To assist in calculating the baseline case (and the corresponding credits) some jurisdictions have instituted a protocol with respect to various industries or activities. Alberta has identified 23 quantification protocols which include, for example, acid gas injection, enhanced oil recovery, pork and beef operations, and solar and wind powered electricity systems.[318]

Regular emitters who cannot meet their required reduction targets can purchase offset credits in respect of their GHG emissions. Mandatory GHG emission regimes necessarily imply emissions trading for many industry participants and as such many businesses are considering acting early to position themselves.

B. ENVIRONMENTAL ASSESSMENT PROCESS

On 12 March 2009, two new federal regulations came into force: the *Regulations Amending the Exclusion List Regulations, 2007*[319] and the *Infrastructure Projects Environmental Assessment Adaptation Regulations*.[320] These regulations were promulgated as part of the Federal government's efforts to stimulate the Canadian economy due to the recent economic downturn. In essence, the Regulations would exempt potentially thousands

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318 See "Approved Alberta Protocols," online: Carbon Offset Solutions <http://carbonoffsetsolutions.climatechangecentral.com/offset-protocols/approved-alberta-protocols>.
319 S.O.R./2009-88 [*Exclusion Regulation*].
320 S.O.R./2009-89 [*Adaptation Regulation*].

of proposed infrastructure projects from environmental assessments under the *CEAA*.[321] Through the *Adaptation Regulation*, the federal Minister of the Environment was given the authority to exempt virtually any federally funded infrastructure project from the assessment process, by relying on a corresponding provincial assessment process, or if otherwise deemed appropriate. A regulatory impact analysis statement accompanying the Regulation states:

> First Ministers have agreed to work together on a number of important actions to provide stimulus to the Canadian economy. One of the actions identified is to streamline the regulatory and environmental approvals process for infrastructure projects to avoid unnecessary overlap and duplication, while continuing to protect the environment. Concerns have been expressed that federal environmental assessment requirements can unnecessarily slow down funding decisions, particularly for small community and transportation infrastructure projects that have insignificant environmental effects. Another area of concern is situations where a federal environmental assessment is triggered after the completion of a provincial assessment or relatively late in the project development process. Within the context of the current economic situation, there is a need to modify the environmental assessment process, through existing legislative authority, to make it more efficient so as not to impede more timely decisions on public infrastructure projects without jeopardizing protection of the environment.[322]

The impact statement goes on to state that "[t]he direct cost savings related to a reduced number of environmental assessments is estimated to be $100 to $150 million."[323] These economic benefits would, in the government's view, have almost no corresponding negative effect as the infrastructure projects to be exempted from a federal assessment through the *Exclusion Regulation* are thought to produce only insignificant adverse environmental impacts. For non-excluded projects the government could, through the *Adaptation Regulation*, simply rely on an existing provincial process. Both the *Exclusion Regulation* and *Adaptation Regulation* contain a sunset clause, and are set to expire in March 2011.

In April 2009, the Sierra Club of Canada filed an originating notice in the Federal Court, seeking to have the Regulations struck as being ultra vires the federal government.[324] The ultimate result of these challenges may help to set some parameters on the federal government's discretion in amending the environmental assessment process set out in the *CEAA* through regulation. Should the Regulations be upheld, and despite the sunset clauses contained therein, these regulations may illustrate a growing trend toward reducing or eliminating the assessment process where a corresponding government initiative is at stake.

C. CARBON CAPTURE AND STORAGE

Carbon capture and storage (CCS) technology has been a pervasive subject recently, of particular interest to the oil sands industry and electrical generation plants powered by fossil fuels. At its most basic, CCS involves the capture of CO_2, its subsequent separation from other emissions, and the dehydration, compression, and ultimate transportation via pipeline

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321 *CEAA*, *supra* note 155. Relevant projects for the purposes of the *Exclusion Regulation* and the *Adaptation Regulation* are those funded through the federal *Building Canada: Modern Infrastructure for a Strong Canada* (Ottawa: Government of Canada, 2007).
322 Regulatory Impact Analysis Statement, C. Gaz. 2009. II. Vol. 143, 6.
323 *Ibid.*
324 *Sierra Club of Canada v. Canada (A.G.)* (15 April 2009), Toronto T-595-09 (F.C.T.D.).

to a storage site where it is injected one to two kilometres deep into rock formation. Monitoring ensures there is no leakage or impact on either public safety or the environment. In an alternate process, CO_2 can be injected into existing oil and gas reservoirs in order to enhance recovery.

In July 2008, the Alberta government committed $2 billion in funding for the development of CCS technology; the provincial government has stated its belief that such technology is vital for Canada to achieve its 2020 target CO_2 emission levels (being a reduction of carbon emissions by 20 percent from current levels).[325] Under its ecoENERGY Technology initiative, the federal government recently allocated $140 million into eight private sector partnerships for the development and demonstration of CCS technologies.[326] EcoENERGY was followed by a funding commitment of $1.5 billion over nine years to promote biofuels, such as ethanol and biodiesel. This latter initiative complements Ottawa's 2006 renewable fuel standard, which requires five per cent renewable fuel in gasoline and two per cent in diesel fuel in the 2010-2012 timeframe.[327]

While CCS has not been implemented on a large scale in Canada, Saskatchewan is home to the world's first CO_2 measuring, monitoring, and verification initiative: EnCana's Weyburn Enhanced Oil Recovery Project. In 2000, EnCana began injecting significant amounts of CO_2, which would otherwise be vented to the atmosphere into the Weyburn oilfield with a view to increasing oil production. According to EnCana, more than 13 million tonnes of CO_2 have been sequestered since the initiative began and it is anticipated that a total of 30 million tonnes of CO_2 will be permanently sequestered over the lifespan of the project.[328]

VI. ELECTRICAL GENERATION AND TRANSMISSION

A. DEREGULATION

1. *MICRO-GENERATION REGULATION* AND AUC *RULE 024: RESPECTING MICRO-GENERATION*

The Government of Alberta has developed a regulatory scheme allowing Albertans to generate environmentally friendly electricity for their own use and receive credit for any excess power they may deliver to the electricity grid. This is the intended purpose behind the *Micro-generation Regulation*[329] promulgated on 1 February 2008.

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325 Government of Alberta, *Talk about Carbon Capture & Storage* (Edmonton: Alberta Energy, 2009), online: Alberta Energy <http://www.energy.gov.ab.ca/Org/pdfs/FactSheet_CCS.pdf>.

326 "CCS Technology: Smaller Pieces of Canada's Big Green Puzzle" (30 March 2009), online: Centre for Energy <http://www.centreflow.ca/2009/03/30/ccs-technology-%E2%80%93-smaller-pieces-of-canada %E2%80%99s-big-green-puzzle/>.

327 "A Leaner, Green Canada?," online: Climate Change Central <http://www.climatechangecentral.com/ publications/c3-views/april-2009/turning-point-for-canada>.

328 "EnCana wins Emerald Award," online: EnCana <http://www.encana.com/aboutus/awards/2007/ P005333.html>.

329 Alta. Reg. 27/2008.

The AUC has responsibility to oversee implementation of the Regulation and has issued *Rule 024: Rules Respecting Micro-Generation*.[330] *Rule 024* and the Regulation implement processes that simplify approvals and interconnection agreements between micro-generating customers and the owners of electric distribution systems. The Regulation defines micro-generation as the generation of electric energy from a generating unit that: "(i) exclusively uses sources of renewable or alternative energy; (ii) is intended to meet all or a portion of the customer's electricity needs; (iii) is … sized to the customer's load or anticipated load"; and, (iv) has a total nominal capacity of one megawatt or less.[331]

VII. ABORIGINAL CONSULTATION

Aboriginal consultation has become an increasingly important step in the development of virtually any oil and gas or power project in Canada. Determining who is required to consult with whom, when, where, and how has never been a straightforward or simplistic process. Despite some recent directives by government, properly navigating through the consultation matrix may be becoming increasingly complex. Such was evident in the decisions of the NEB on the SemCAMS Redwillow Pipeline Project[332] and the Westcoast Energy Inc. Application for construction of the South Peace Pipeline,[333] discussed at Part II.D, above.

A. DIRECTIVES, GUIDELINES, AND INITIATIVES

In February of 2008, the Government of Canada published its *Aboriginal Consultation and Accommodation: Interim Guidelines for Federal Officials to Fulfill the Legal Duty to Consult*.[334] These guidelines were designed as part of the federal government's action plan to create a more coherent, consistent, and coordinated approach to aboriginal consultation and accommodation for the myriad federal departments and agencies whose activities trigger the legal duty to consult.

The federal Major Projects Management Office (MPMO) in consultation with the NEB and other key departments and agencies responsible for the review of major resource projects[335] also, in December 2008, published *Early Aboriginal Engagement: A Guide for Proponents of Major Resource Projects*.[336] This guide sets out the various considerations and steps that should be taken by project proponents before filing a Project Description with the MPMO.

330 Alberta Utilities Commission, *Rule 024: Rules Respecting Micro-Generation* (17 June 2008), online: AUC <http://www.auc.ab.ca/rule-development/micro-generation/Documents/Micro_Generation/Rule 024.pdf> [*Rule 024*].

331 *Micro-generation Regulation*, *supra* note 329, s. 1(1)(h).

332 *SemCAMS*, *supra* note 63.

333 *Westcoast*, NEB, *supra* note 65.

334 Canada, *Aboriginal Consultation and Accommodation: Interim Guidelines for Federal Officials to Fulfill the Legal Duty to Consult* (Ottawa: Government of Canada, 2008).

335 These departments and agencies include: Canadian Nuclear Safety Commission, Environment Canada, National Energy Board, Fisheries and Oceans Canada, Natural Resources Canada, Indian and Northern Affairs Canada, Canadian Environmental Assessment Agency, and Transport Canada.

336 Major Projects Management Office, *Early Aboriginal Engagement: A Guide for Proponents of Major Resource Projects* (Ottawa: Government of Canada, 2008).

In 2008, the NEB also adopted its own Enhanced Aboriginal Engagement strategy.[337] This strategy builds on the NEB's existing program and includes more proactive steps to engage and provide regulatory assistance to potentially affected Aboriginal groups at earlier stages in the approval process.

B. *STANDING BUFFALO DAKOTA FIRST NATION V. ENBRIDGE SOUTHERN LIGHTS GP INC.*

As reported in the article, "Recent Regulatory and Legislative Developments of Interest to Oil and Gas Lawyers 2007-2008,"[338] the Standing Buffalo Dakota First Nation (Standing Buffalo) brought a motion at the hearing of the Enbridge Southern Lights GP Inc. (Enbridge) pipeline application[339] for a declaration that the NEB lacked jurisdiction to hear the application as, among other things, it failed to satisfy itself that the Crown had fulfilled its duty to consult and accommodate Standing Buffalo. The NEB dismissed the motion and ultimately granted the application.

Briefly, the facts of that matter were that Standing Buffalo had outstanding claims for Aboriginal title over certain tracts of Dakota traditional land (which, in Canada, is claimed to span through parts of southern Alberta, southern Saskatchewan, much of Manitoba, and into southwestern Ontario). Standing Buffalo did not have existing treaty rights and the federal government had ceased treaty discussions in late 2007. Reserve lands in southern Saskatchewan had, however, been ceded to the First Nation. At the hearing of Southern Lights, the Aboriginal group argued that the NEB had erred in law and jurisdiction in choosing to hear the pipeline application without first determining conclusively whether Standing Buffalo had a potential credible claim to Aboriginal title, such that their consent would be required. Further, it was argued that the NEB erred in failing to satisfy itself that the Crown had discharged its duty to consult and accommodate the Standing Buffalo's interests in relation to their claim for Aboriginal title. In further submissions, Standing Buffalo argued that the NEB ought to have compelled the Government of Canada to appear and make submissions at the Southern Lights hearing.

The only new pipeline required for the Southern Lights project was hundreds of kilometres from the Standing Buffalo reserve in Saskatchewan; the Aboriginal group claimed, however, that it traversed the larger traditional Dakota lands. Further, several parcels of Crown lands within Dakota territory were to be ceded to the Aboriginal group as a replacement for certain reserve lands that the Crown had allowed to be flooded. As these lands had not, as yet, been designated, the First Nation took the position that it had a potential claim over any available Crown lands on its traditional territories.

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337 See National Energy Board, *Annual Report 2008 to Parliament* (Calgary: National Energy Board, 2009) at 18.

338 Lowe & Liteplo, *supra* note 156 at 522, 525-27.

339 *Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP and Enbridge Pipelines Inc.* (February 2008), Reasons for Decision OH-3-2007 (NEB), online: NEB <http://www.neb-one.gc.ca> [*Southern Lights*].

Following the release of the decision, Standing Buffalo sought, among other things, leave to appeal that decision to the Federal Court of Appeal.[340] In September of 2008, Standing Buffalo was granted leave. Unfortunately, no reasons were provided on the decision to grant leave and, as such, it can be assumed that the issues on appeal will be those set out in the leave application, namely: (1) whether the NEB erred in law and jurisdiction in choosing to hear the Enbridge application without first determining conclusively that the Crown had discharged its duty to consult and accommodate the interests of Standing Buffalo relating to their claim for Aboriginal title; and (2) whether the NEB denied Standing Buffalo a fair hearing when it determined that Canada did not need to be a participant in the hearing.

Around the same time that leave was granted on Southern Lights, leave to appeal was also granted to Standing Buffalo on similar grounds in NEB decisions regarding Enbridge's Alberta Clipper Project[341] and TransCanada's Keystone Pipeline Project.[342] Sweetgrass First Nation and Moosomin First Nation have also sought and received leave to appeal the decision of the NEB in *Clipper*.[343]

On 6 March 2009, Enbridge filed a motion to consolidate the appeals in *Clipper*, *Southern Lights*, and *Sweetgrass*. TransCanada has been granted leave to file motion materials in the Enbridge consolidation motion regarding the related appeal in *Keystone*.[344]

C. *BROKENHEAD OJIBWAY NATION V. CANADA (ATTORNEY GENERAL)*

The Applicants in *Brokenhead*[345] sought judicial review of the decisions of the NEB in *Southern Lights*,[346] *Clipper*,[347] and *Keystone*.[348] In each of these matters, the First Nation[349] claimed outstanding treaty, treaty protected inherent rights, and indigenous cultural rights over lands in the vicinity of the pipeline projects in question. Similar to the claims of Standing Buffalo and Sweetgrass First Nation, above, Ojibway claimed that the NEB failed

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340 *Standing Buffalo Dakota First Nation v. Enbridge Southern Lights GP* (19 September 2008), Calgary 08-A-28 (F.C.A.).

341 *Enbridge Pipelines Inc.: Alberta Clipper Expansion Project* (February 2008), Reasons for Decision OH-4-2007 (NEB), online: NEB <http://www.neb-one.gc.ca> [*Clipper*]; *Standing Buffalo Dakota First Nation v. Enbridge Pipeline Inc.* (22 October 2008), Regina A-537-08 (F.C.A.).

342 *Keystone, supra* note 25; *Standing Buffalo Dakota First Nation v. Trans-Canada Keystone Pipeline* (22 October 2008), Regina A-542-08 (F.C.A.).

343 Since this article was written this appeal was heard and dismissed by the Federal Court of Appeal: see *Standing Buffalo Dakota First Nation v. Enbridge Pipelines Inc.*, 2009 FCA 308, 395 N.R. 355 [*Sweetgrass*]. On 14 December 2009, appliation for leave to appeal to the Supreme Court of Canada was filed: *Sweetgrass First Nation v. Canada (National Energy Board)*, [2009] S.C.C.A. No. 493 (QL).

344 Since this article was written, this appeal was heard and dismissed by the Federal Court of Appeal: see *Sweetgrass, ibid.* On 21 December 2009, application for leave to appeal to the Supreme Court of Canada was filed: see *Standing Buffalo Dakota First Nation v. TransCanada Keystone Pipeline GP Ltd.*, [2009] S.C.C.A. No. 501 (QL).

345 *Brokenhead Ojibway Nation v. Canada (Attorney General)*, 2009 FC 484, [2009] 3 C.N.L.R. 36 [*Brokenhead*].

346 *Southern Lights, supra* note 339; *Brokenhead Ojibway Nation v. Canada (A.G.)* (9 June 2008), Montreal T-921-08 (F.C.T.D.).

347 *Clipper, supra* note 341; *Brokenhead Ojibway Nation v. Canada (A.G.)* (10 June 2008), Montreal T-925-08 (F.C.T.D.).

348 *Keystone, supra* note 24; *Brokenhead Ojibway Nation v. Canada (A.G.)* (8 February 2008), Montreal T-225-08 (F.C.T.D.).

349 The applicants were actually seven First Nations, each of whom were successors to the Ojibway First Nation (Ojibway), who entered into *Treaty No. 1*, Her Majesty the Queen and The Chippewa and Cree Indians, 3 August 1871 (Ottawa: Queen's Printer and Controller of Stationery, 1957).

to satisfy itself that the Crown had fulfilled its legal obligation to consult and accommodate the First Nation prior to granting its approval.

The applications for judicial review of the NEB decisions in *Southern Lights* and *Clipper* were heard in Winnipeg, Manitoba on 16 January 2009.[350] On 12 May 2009, the Federal Court rendered its judgment with a single set of reasons and dismissed the applications.

In his reasons, Barnes J. declined to make any determination regarding the outstanding treaty claims; rather, he opted to conduct his analysis on the assumption that Ojibway's claim for additional treaty lands and for continued traditional use in southern Manitoba was credible.[351] Ultimately, however, the Federal Court found that the proposed pipelines, which were almost entirely designed over existing rights-of-way and on privately owned lands, would have a negligible impact on any traditional lands held or that could be claimed in future.[352]

A couple of more general statements made by the Federal Court are also worth mention. First, Barnes J. rejected the proposition that the duty to consult is engaged whenever lands are developed for a public purpose. Rather, "[t]here must be some unresolved non-negligible impact arising from such a development" to engage the duty to consult.[353] Second, the Court seemed to find that, if the process of consultation and accommodation undertaken by the NEB and the project proponent was adequate and accessible to all relevant aboriginal groups, the Crown would not owe a distinct duty to consult from that undertaken by the NEB.[354] Lastly, the Court confirmed that the consultation process is reciprocal and, as such, could not be intentionally frustrated by either party.[355]

D. *ATHABASCA CHIPEWYAN FIRST NATION V. ALBERTA (MINISTER OF ENERGY)*[356]

The Athabasca Chipewyan First Nation (ACFN) is the successor to an Aboriginal group that signed *Treaty No. 8*,[357] residing in and around the Athabasca River in Northern Alberta.

In an originating notice, filed in the Alberta Court of Queen's Bench in December 2008, ACFN challenged, in essence, the entire land tenure system for oil sands in Alberta, claiming that the Crown owed a duty to consult before land was sold or otherwise ceded to industry for the ultimate development of the oil sands.

More specifically, in the Originating Notice, ACFN claimed a declaratory order that the Minister of Energy had a duty to consult and accommodate ACFN before it granted any rights or permits to third parties for the oil sands. The First Nation further alleged that the

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350 On 16 September 2008, the Ojibway wrote to the Federal Court of Appeal requesting an adjournment of its application for judicial review of the *Keystone* decision, *sine die*.

351 *Brokenhead*, *supra* note 345 at para. 24.

352 *Ibid.* at para. 30.

353 *Ibid.* at para. 34.

354 Despite these statements, the Court went on to surmise that a specific duty to consult by the Crown may arise where the lands to be traversed are clearly part of an outstanding land claim; in those circumstances, the NEB would be ill-equipped to deal with the specific land claim (*ibid.* at para. 44).

355 *Ibid.* at para. 42.

356 2009 ABQB 576, [2009] A.J. No. 1143 (QL).

357 *Treaty No. 8*, 21 June 1899 (Ottawa: Queen's Printer and Controller of Stationery, 1966).

duty owed is of an ongoing nature. ACFN argued that this preliminary permit process effectively facilitated the larger development process. Reasoning followed that consultation at this early stage could be the most instrumental in managing the intensity of the ultimate development. Once the parties are at the stage of specific project approvals it is, ACFN argues, too late. For this reason consultation and accommodation must take place before treaty lands are transferred. This is a unique challenge to the development of the oil sands in that the First Nation is seeking to exert its Constitutional rights to consultation before a project proposal is even submitted to a regulatory board.

At the root of these disputes is the base contention by First Nations that, in order to be meaningful, consultation and accommodation must take place at a far earlier stage in the planning process, before the project is underway or the pipeline is in the ground.

It is uncertain how the courts and regulators will react to these various challenges. Reviewing the trends and assessing where they are likely to go, however, is important for all stakeholders in understanding the future development of resources in Canada.

VIII. OFFSHORE AND EASTERN CANADA

A. *CANADA OIL AND GAS DRILLING AND PRODUCTION REGULATIONS*

Offshore oil and gas exploration and development is currently governed by a system of separate *Canada Oil and Gas Drilling Regulations*[358] and *Canada Oil and Gas Production and Conservation Regulations*[359] that exist, in mirror form, under three separate pieces of legislation. The *Canada-Newfoundland Atlantic Accord Implementation Act*,[360] the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*[361] (collectively, the *Offshore Accord Acts*), and the *Canada Oil and Gas Operations Act*[362] provide the authority for these regulations. Further, there are three offshore jurisdictions in Canada whose regulations are administered by three separate boards. The Canada-Newfoundland and Labrador Offshore Petroleum Board (CNLOPB) administers regulations off the coast of Newfoundland and Labrador; the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) administers regulations off the coast of Nova Scotia; and the NEB administers regulations in the Northwest Territories, Nunavut and Sable Island, Arctic, Hudson's Bay, James Bay, Gulf of St. Lawrence, Bay of Fundy, and offshore areas of British Columbia.

The proposed *Canada Oil and Gas Drilling and Production Regulations*[363] attempt to re-evaluate the current dual regulatory regime and amalgamate the *Drilling Regulations* and *Production and Conservation Regulations*. The *Production Regulations*, which apply to offshore activities under the jurisdiction of the NEB, were published in the *Canada Gazette* on 18 April 2009. The proposed regulatory text was open for comment for a period of 45 days until 2 June 2009.

358 S.O.R./79-82 [*Drilling Regulations*].
359 S.O.R./90-791 [*Production and Conservation Regulations*].
360 S.C. 1987, c. 3.
361 S.C. 1988, c. 28.
362 R.S.C. 1985, c. O-7 [*COGOA*].
363 C.R.C. c. 1517 [*Production Regulations*].

According to the Regulatory Impact Analysis Statement,[364] which precedes the proposed regulation, the amendments attempt to address three main issues: the high level of duplication that exists between the two separate regulations; the inefficiencies that arise due to the prescriptive nature of the detailed requirements of the current regulations; and the implementation of new management systems-based models to better manage safety and environmental risk.[365]

The *Production Regulations* are to be implemented in mirror form in the other two offshore jurisdictions (that is, Nova Scotia and Newfoundland and Labrador). This consistent regulatory framework is meant to create predictability in national exploration and development activities.

There will be certain differences in the mirror regulations because of the way that the enabling legislation operates. First, the *COGOA* regulations contain requirements for onshore activities because the legislation applies to those oil and gas activities while the *Offshore Accord Acts* do not. Second, the *Canada Labour Code*[366] applies to the *COGOA* so those regulations will not need duplicative labour provisions. Third, the *Offshore Accord Acts* require that information on operating and capital expenditures are included in annual production reports. The *COGOA* contains no such requirement and therefore the regulations will not include these specific obligations.

Under the *Offshore Accord Acts* and the *COGOA*, the NEB, CNLOPB, and CNSOPB are responsible for ensuring compliance and enforcement of the new regulations within their respective jurisdictions.

IX. LIQUIFIED NATURAL GAS

A. NEB ENERGY MARKET ASSESSMENT: LIQUIFIED NATURAL GAS

In February 2009, the NEB published an energy market assessment entitled *Liquified Natural Gas: A Canadian Perspective*.[367] The Market Assessment stated that in 2009, the demand outlook for liquified natural gas (LNG) had declined due to, among other things, weak financial and credit markets, slow economic growth, volatile energy prices, and an increase in unconventional gas production in North America.[368] In North America, as elsewhere, it is still anticipated however that reliance on LNG will increase in the future.

With particular reference to Canada, the Market Assessment made note of the fact that the Canaport LNG Terminal in Saint John is currently the only receiving terminal in Canada.[369] In June 2009, Canaport reported that the facility was complete and that the initial

[364] Regulatory Impact Analysis Statement, C. Gaz. 2009. I. 1096 (*Canada Oil and Gas Drilling and Production Regulations*).
[365] *Ibid.* at 1096-97.
[366] R.S.C. 1985, c. L-2.
[367] National Energy Board, *Liquified Natural Gas: A Canadian Perspective* (Calgary: National Energy Board, 2009) [Market Assessment].
[368] *Ibid.* at viii.
[369] *Ibid.* at 27.

commissioning shipment was expected by the end of June 2009.[370] In addition to the Canaport LNG Terminal, there are six other proposed LNG receiving terminals in various stages of development in Canada, including one in Nova Scotia, two in British Columbia, and three in Quebec. An additional proposed LNG storage and trans-shipment project is proposed for Newfoundland. The proposed Kitimat LNG facility in British Columbia has now switched to a proposal for the construction of a gas liquefaction and export terminal.[371]

Looking forward, LNG is expected to play a role in supplementing declining supply from conventional sources in Western and Atlantic Canada, and in meeting increasing demands that may not be met from more traditional sources.[372]

B. NEB DECISION GH-1-2008: *REPSOL ENERGY CANADA LTD.*[373]

Repsol Energy Canada Ltd. (Repsol) applied to the NEB on 27 December 2007 for a licence to import natural gas in liquefied form into Canada at the Canaport LNG marine terminal near Saint John, New Brunswick. Repsol also applied for a separate licence to export that natural gas via the Emera Brunswick pipeline to its interconnect with the Maritimes and Northeast pipeline in the U.S. The decision is noteworthy as it was the first application of its kind in Canada, and the first time that the NEB had been required to interpret s. 118(c) of the *NEB Act*, on an export license application.[374] As noted by the NEB, when considering licence applications to export natural gas, the Board employs the Market-Based Procedure (MBP), although there has not been an export licence application before the NEB since 1999.[375]

To provide context for its decision, the Board looked back to the Natural Gas Markets and Pricing Agreement of 31 October 1985 (the Halloween Agreement) and its methodology for implementing the MBP, which was historically designed to establish that the proposed export of natural gas would be surplus to Canadian needs and in the public interest.

Repsol argued that special circumstances applied to this particular application since the export of regasified LNG was not the same as a traditional export in that the LNG imports that were first entering Canada "would enhance the overall supply available to meet Canadian requirements."[376] During the course of the hearing, Repsol expanded its application to request that it be permitted to export domestically produced natural gas in addition to, or in lieu of, the imported regasified LNG.

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370 Canaport LNG, News Release, "Canapart LNG Terminal to Begin First Phase of Operations" (18 June 2009), online: Canaport LNG <http://www.canapartlng.com/pdfs/news_release_june_18_2009.pdf>.

371 Market Assessment, *supra* note 367 at 28.

372 *Ibid.* at 27. See also Natural Resources Canada, *Canadian LNG Import and Export Projects: Status as of May 2009* (Ottawa: Government of Canada, 2009).

373 *Repsol Energy Canada Ltd.* (September 2008), Reasons for Decision GH-1-2008 (NEB), online: NEB <http://www.neb-one-.gc.ca> [*Repsol*].

374 The *NEB Act*, *supra* note 1, s. 118(c) [emphasis added] provides: "On an application for a licence, the Board shall have regard to all considerations that appear to it to be relevant and shall … (c) *where oil or gas is to be exported* and subsequently imported *or where oil or gas is to be imported, have regard to the equitable distribution of oil or gas, as the case may be, in Canada*."

375 *Repsol*, *supra* note 373 at 4.

376 *Ibid.* at 6.

Despite the Board's recognition that the gas market in Canada has "evolved" since the Halloween Agreement,[377] the Board found that there was no compelling reason to modify the MBP insofar as it relates to the assessment of licenses to export Canadian sourced gas. While noting that imported gas was incremental to existing Canadian supply, the Board nevertheless held that it was necessary to assess the application in the context of both increased supplies and future Canadian requirements.

In considering the "equitable distribution" provision of s. 118, the Board felt it appropriate to analyze whether Repsol would make gas available to Canadian buyers on similar terms and conditions as those that would be offered to export buyers.[378]

The Board reviewed the arrangements for the importation of the LNG, which would be purchased by Repsol from its affiliate in Madrid Spain, and delivered to the Canaport LNG Terminal. A further related company, Repsol Energy North America Corporation (RENA), would then purchase the gas at the Canada-U.S. border and resell it into the American marketplace. These supply arrangements were not supported by any specific supply source, but were supported by the Spanish parent's corporate warranty for supply. The supply contracts, transportation arrangements, and arrangements with Canaport (which is 75 percent owned by Repsol affiliates) were for 25-year terms. RENA agreed to make gas available to Canadian buyers in the Maritimes on similar terms and conditions, including a similar price.

The contractual commitments, including that to make Canadian gas available to the Canadian market, fulfilled the equitable distribution requirement of s. 118(c). The Board ultimately approved Repsol's import application, together with the 25-year term of the license, noting that, "because of the long-term nature of these assets and commitments, Repsol will make every effort to obtain LNG supply from its affiliates or third parties in order to highly utilize its assets to secure a return on its investments."[379]

As discussed, there were two components to the export licence application: firstly, Repsol sought the export of regasified LNG from the Canaport LNG terminal; and secondly, Repsol sought domestic production in the event it was connected to the Emera Brunswick Pipeline in the future. Repsol foresaw the possibility of acquiring Canadian gas as part of its marketing activities and sought to use domestic gas for export under the same licence.

Although Repsol provided the supply documentation regarding the potential import of LNG, it did not file any evidence to show that domestic gas was available for export at the time of the application. Nor did it provide evidence of facilities that would be needed to connect future supply or any environmental assessment requirements that would underpin any such facilities.

Rather, Repsol relied on its 25-year firm service transportation agreements with Maritimes and Northeast Pipeline LLC, as well as market studies showing a demand for the exported gas and a paucity of demand in the Atlantic Canadian market — that market simply does not

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377 *Ibid.* at 7.
378 *Ibid.* at 9.
379 *Ibid.* at 13.

have the capacity to absorb the entire output from the Canaport LNG terminal. RENA also indicated that, in addition to its marketing activities to third parties in the U.S., it might also indirectly serve markets in Atlantic and Central Canada through the re-importation of exported gas (that is, the subject matter of s. 118 (c)).

The Board noted that imported LNG would be incremental to Canadian production and could enhance supply availability to Canadians.[380] Despite a request from the Board, Repsol did not, however, address the impact on present and future Canadian requirements of exporting up to one Bcf/d of Canadian produced natural gas. Repsol also failed to demonstrate that it had any domestic gas under its control.[381]

Accordingly, the Board granted the export licence for the LNG-sourced gas but denied the application for export of any Canadian sourced gas, indicating that Repsol could apply in the future if such gas supply and associated facilities became available.

Also, the Board pointed out that LNG imported into Canada does not form part of Canada's reserves and therefore is not subject to the terms of the *North American Free Trade Agreement between the Government of Canada, the Government of the United Mexican States and the Government of the United States of America*.[382] Accordingly, the imported LNG that would be regasified and sold into U.S. markets under licence by Repsol would not qualify as gas "from Canada" for the purposes of the *NAFTA*.[383]

X. COAL GASIFICATION

A. ERCB APPROVAL OF SWAN HILLS SOUTH MANNVILLE FORMATION

The ERCB approved an experimental scheme under the *OGCA* for underground coal gasification near Swan Hills, Alberta.[384] The approval included operation of three wells, one of which would be used for fluid injection. The fluids approved for injection included oxygen, water, ignition fluids, and tracers. The approval included monitoring and reporting conditions. Certain information was held to be confidential including production and injection volumes, make-up water volumes, temperature data, microseismic data, composition of fluids and produced materials, pressure measurements, and core analysis. A separate application to satisfy all requirements of *Directive 051: Injection and Disposal Wells — Well Classifications, Completions, Logging, and Testing Requirements*[385] was required. The approval was granted until 30 April 2013.

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380 *Ibid.* at 15.
381 *Ibid.* at 20.
382 17 December 1992, Can. T.S. 1994 No. 2 (entered into force 1 January 1994) [*NAFTA*].
383 *Repsol*, *supra* note 373 at 22.
384 See *Summary of Orders and Approvals* (December 2009) at 50, online: ERCB <http://www.ercb.ca/docs/documents/orders/IBO_Summary_200912.pdf>.
385 Energy and Utilities Board, *Directive 051: Injection and Disposal Wells — Well Classifications, Completions, Logging, and Testing Requirements* (Calgary: Energy and Utilities Board, 1994).

XI. ROYALTY REGIME

A. BILL 47: *MINES AND MINERALS (NEW ROYALTY FRAMEWORK) AMENDMENT ACT, 2008*

In response to reports criticizing the lack of transparency and accountability to Alberta residents with respect to the government's handling of royalties, Bill 47: *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*[386] was introduced. Bill 47 set forth amendments to the *Mines and Minerals Act*[387] with the view that seven comprehensive regulations will be enacted, three of which would enable the implementation of a new price sensitive royalty regime. According to the Alberta government, the passage of Bill 47 contemplates the maintenance of Alberta's competitive advantage by attracting new investment, development, and jobs and empowering the Province to pursue new opportunities for value-added energy developments. Bill 47 received royal assent on 2 December 2008. The vast majority of the bill came into force on 2 December 2008.

The amendments introduce a sliding scale, price sensitive royalty scheme that will take into account fluctuating commodity prices. Higher royalty rates will be levied when commodity prices are high, and lower royalty rates will be levied when commodity prices are low, with the intention of encouraging investment and development. The amendments to the *M&M Act*, among other things, further increase the government's capacity to take bitumen or other products from oil sands operators in lieu of cash royalties, and increase the government's investigation and inspection powers.

The regulations enacted as a result of Bill 47 are the *Natural Gas Royalty Regulation, 2009*;[388] *Oil Sands Royalty Regulation, 2009*;[389] *Petroleum Royalty Regulation, 2009*;[390] *Deep Oil Exploratory Well Regulation*;[391] *Natural Gas Deep Drilling Regulation*;[392] *Oil Sands Allowed Costs (Ministerial) Regulation*;[393] and *Bitumen Valuation Methodology (Ministerial) Regulation*.[394]

Alberta's Information and Privacy Commissioner has raised some concerns regarding cl. 10 of Bill 47, which purports to expand the paramountcy of the provision of royalty related information contained in s. 50(4) of the *M&M Act*. According to the Commissioner, the amendments effectively eliminate the public's ability to access information related to Alberta royalties for five years, even if the *Freedom of Information and Protection of Privacy Act*[395] would otherwise allow access. The alleged purpose behind this proposed amendment was to establish greater certainty about access limitations to extremely confidential and sensitive industry information gathered by the government with respect to

386 Bill 47, *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*, 1st Sess., 27th Leg., Alberta, 2008 (assented to 2 December 2008), S.A. 2008, c. 36 [Bill 47].
387 R.S.A. 2000, c. M-17 [*M&M Act*].
388 Alta. Reg. 221/2008.
389 Alta. Reg. 223/2008.
390 Alta. Reg. 222/2008.
391 Alta. Reg. 225/2008.
392 Alta. Reg. 224/2008.
393 Alta. Reg. 231/2008.
394 Alta. Reg. 232/2008.
395 R.S.A. 2000, c. F-25 [*FOIP*].

royalties. A time frame of five years was chosen as legislators believed that the competitive edge of such information would dissipate within this time frame.

This proposed amendment has otherwise proven to be extremely controversial. Some have viewed the amendment as providing a blanket exemption from *FOIP* and, therefore, a vehicle for the government to hide royalty rate inequities between petroleum producers. The public would be unable to access information about the amount of royalties paid by individual companies, thereby depriving Albertans from access to information about the resources they own. Conversely, proponents view the amendment as necessary to strengthen the investment security of Alberta's energy.