RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO ENERGY 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 decisions of key regulatory agencies such as the National Energy Board, the Ontario Energy Board, the Alberta Energy Resources Conservation Board, the Alberta Surface Rights Board, and the Alberta Utilities Commission, as well as related court decisions. In addition, the authors review a variety of key policy and legislative changes from the federal and provincial levels.

Cet article identifie les derniers développements réglementaires et législatifs d'intérêt pour les avocats travaillant dans le domaine pétrolier et gazier. Les auteurs examinent plusieurs domaines, étudiant les décisions d'organismes de réglementation importantes comme l'Office national de l'énergie, la Commission de l'énergie de l'Ontario, le Alberta Energy Resources Conservation Board, le Alberta Surface Rights Board et la Alberta Utilities Commission, et les décisions relatives des cours. En outre, les auteurs traitent de plusieurs changements importants sur le plan politique et législatif des niveaux fédéral et provinciaux.

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* Bennett Jones LLP. The authors would like to acknowledge the contributions of our colleagues Karen Beattie, Celeste Hutchinson, and Sean Assié in the preparation of this article.

I. INTRODUCTION

The purpose of this article is to highlight and discuss regulatory and legislative developments of interest to energy lawyers that have arisen during the 12-month period from May 2009 through to April 2010. This article focuses primarily on decisions of the National Energy Board (NEB) and the Energy Resources Conservation Board (ERCB), and appellate reviews of those decisions. In addition, this article highlights changes to regulatory policies and procedures for each of these regulators and reviews recent decisions and policy initiatives of other regulatory agencies in Canada that will be of interest to those involved in the energy industry.

II. REGULATORY DECISIONS AND RELATED JURISPRUDENCE

A. NATIONAL ENERGY BOARD

The year 2009 marked the 50 year anniversary of Canada's energy regulator, the NEB. More than 50 years ago, on 23 April 1959, the Minister of Trade and Commerce — the Honourable Gordon Churchill — made a motion to introduce into the House of Commons a measure "to provide for the establishment and operation of a national energy board."[1] Bill C-49 was first introduced on 19 May 1959,[2] identifying in the Explanatory Note the proposed establishment, operation, and authority of the NEB:

> The purpose of this Bill is to establish a National Energy Board which shall, in order to assure to the people of Canada the best use of energy resources in this country, regulate in the public interest the construction and operation of oil and gas pipe lines subject to the jurisdiction of the Parliament of Canada, the tolls charged for transmission by such pipe lines, the export and import of gas, the export of electric power and the construction of those lines over which such power is exported. The Board shall also study and keep under review all matters relating to energy within the jurisdiction of the Parliament of Canada, and shall recommend to the Minister of Trade and Commerce such measures as it considers necessary or advisable in the public interest with regard to such matters. The Bill also authorizes the extension of the export and import provisions to oil.[3]

The inaugural meeting for the first members of the Board was held in Ottawa on 14 August 1959 following receipt of royal assent on 18 July 1959 for the *National Energy Board Act*.[4] Moving into its fifth decade of regulatory leadership,[5] the NEB continues as an independent federal regulatory agency. Regulating energy infrastructure, the Board integrates into its decisions environmental, social, and economic considerations in order to assess the overall public interest.[6]

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1 *House of Commons Debates* (23 April 1959) at 2965 (Hon. Gordon Churchill).

2 Bill C-49, *An Act to provide for the Establishment of a National Energy Board*, 2d Sess., 24th Parl., 1959 (assented to 18 July 1959).

3 Bill C-49, *An Act to provide for the Establishment of a National Energy Board*, First Reading (19 May 1959) Explanatory Note.

4 S.C. 1959, c. 46, as am. by R.S.C. 1985, c. N-7 [*NEB Act*].

5 NEB, "Welcome from Chairman & CEO Gaétan Caron," online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/50yrs/chrwlcm-eng.html>.

6 On 1 April 2010, the NEB's *Strategic Plan 2010-2013* came into effect, clarifying how the Board approaches its regulatory mandate, which includes the promotion of safety and security, environmental protection, and efficient energy infrastructure and markets in the Canadian public interest. See NEB, *Strategic Plan 2010-2013* (Ottawa: NEB, 2010), online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/

Under the umbrella of its enabling and related legislation, the NEB regulates various aspects of the energy industry, including construction and operation of international and interprovincial oil, gas, and commodity pipelines; the construction and operation of international and designated interprovincial power lines; pipeline traffic, tolls, and tariffs; exports and imports of natural gas; and exports of oil, natural gas liquids, and electricity.[7] The NEB regulates frontier oil and gas activities that are not otherwise regulated under joint federal/provincial accords and has responsibilities pursuant to certain sections of the *Northern Pipeline Act*, the *Canada Oil and Gas Operations Act*, and the *Canada Petroleum Resources Act* for both crude oil and natural gas exploration and production in certain areas off of Canada's Arctic coast and frontier lands.[8] While the NEB has always considered that it must examine potential environmental impacts under its public interest mandate, additional environmental responsibilities arise under the *Canadian Environmental Assessment Act* and the *Mackenzie Valley Resource Management Act*.[9]

The following discusses Board decisions and other developments of interest since 1 May 2009.

1. NEB DECISION OH-1-2009: *TRANSCANADA KEYSTONE PIPELINE GP LTD.*[10]

On 27 February 2009, TransCanada Keystone Pipeline GP Ltd. (Keystone) filed an application with the NEB requesting approval pursuant to s. 52 of the *NEB Act* for the construction and operation of the Keystone XL Pipeline (Keystone XL); pursuant to Part IV of the *NEB Act* for approval of market-based negotiated tolls; and pursuant to the *CEAA* for a determination that the construction and operation of Keystone XL would not, or was not likely to, cause significant adverse environmental effects.

a. Project Description and NEB Findings

Keystone XL was proposed as an addition to the existing "Base Keystone," which remained under construction at the time the Keystone XL application was filed with the Board and which included both the original Keystone Pipeline and the Cushing Expansion Project.[11] Keystone XL would require the construction of approximately 529 km of new 36-inch pipeline and related facilities. Keystone XL would have an initial capacity of 700,000 bpd with a price tag of $1.7 billion. Once constructed, Keystone XL would transport crude oil from Hardisty, Alberta to the Canada/U.S. border at Monchy, Saskatchewan, through to

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whwrndrgvrnnc/strtgcpln-eng.pdf>. See also Gaétan Caron, "Regulating for Performance" (Address to NEB Forum 2009, Calgary, 27 May 2009), online: NEB <http://www.neb-one.ca/clf-nsi/rpblctn/spchsndprsnttn/2009/rg/tngprfrmnc/rgltngprfrmnc/rgltngprfrmnc-eng.html>. Chairman Caron noted that "[s]afety is, and always will be, of paramount interest to the NEB."

7 See NEB, *Annual Report to Parliament: 2009* (Calgary: NEB Publications Office, 2010) at 7, online: NEB <http://www.neb-one.gc.ca/clf-nsi/rpblctn/rprt/nnlrprt/2009/nnlrprt2009.pdf>.

8 *Northern Pipeline Act*, R.S.C. 1985, c. N-26; *Canada Oil and Gas Operations Act*, R.S.C. 1985, c. O-7 [*COGOA*]; *Canada Petroleum Resources Act*, R.S.C. 1985 (2d Supp.), c. 36.

9 *Canadian Environmental Assessment Act*, S.C. 1992, c. 37 [*CEAA*]; *Mackenzie Valley Resource Management Act*, S.C. 1998, c. 25.

10 *TransCanada Keystone Pipeline GP Ltd.*, NEB Decision OH-1-2009 (March 2009) [*Keystone*]. All NEB decisions, and the documents pertaining to them, can be found online: NEB <http://www.neb-one.gc.ca>.

11 See *TransCanada Keystone Pipeline GP Ltd.*, NEB Decision OH-1-2007 (September 2007); *TransCanada Keystone Pipeline GP Ltd.*, NEB Decision OH-1-2008 (July 2008).

the U.S. Gulf Coast (USGC), which represented a previously untapped market for crude oil out of the Western Canadian Sedimentary Basin (WCSB).

The NEB issued a hearing order on 12 May 2009. The application was considered by the Board during an 11-day hearing commencing 15 September 2009. Significantly, this was the first application to be considered by the Board that involved the Major Projects Management Office (MPMO), which had been established in October 2007 by the Government of Canada to assist in and improve the coordination of the regulatory review.

In March 2010, the NEB issued its decision approving the construction of the facilities for Keystone XL, concluding that the benefits of Keystone XL would outweigh the burdens.[12] While the Board determined that the applied-for toll methodology would result in just and reasonable tolls that would not be unduly discriminatory, it did not approve the applied-for tariff as, in the Board's view, the tariff did not adequately reflect the intentions of the parties respecting allocation of unapportioned capacity and did not specifically recognize that capacity was to be reserved for uncommitted volumes to ensure equitable treatment for spot shippers.[13] The decision was issued with 22 conditions[14] related to construction, safety, landowner and First Nation consultations, environmental protection, and included an obligation for Keystone to monitor greenhouse gas emissions.[15]

b. Economic Feasibility

The NEB has traditionally considered the adequacy of supply and markets, need, financial arrangements for construction and operation, and the likelihood that tolls will be paid in assessing the economic feasibility of proposed pipeline infrastructure. The Keystone XL proceeding recognized the significant changes to the economic environment that occurred in 2008 and acknowledged the potential impact that these changes could have on Keystone XL. The updated supply and markets evidence that was filed by Keystone at the request of the Board demonstrated a slowdown in oil sands growth, but not a stoppage in such growth.[16] No party filed evidence to contradict Keystone's evidence of supply or markets. The NEB was prepared to accept Keystone's evidence on both supply and markets, despite the uncertainties regarding forecasts of crude oil supply.[17]

One of the main issues of controversy during the proceeding related to the need for additional transportation capacity out of the WCSB. Parties in support of Keystone XL submitted that the long-term transportation arrangements, together with Keystone's acceptance of risk for underutilization, demonstrated the need for Keystone XL.[18] Other parties, including TransCanada's competitor Enbridge Pipelines Inc. (Enbridge), as well as BP Canada Energy Company (BP), Imperial Oil Limited (Imperial Oil), Nexen Inc., and

12 *Keystone*, *supra* note 10 at 79.
13 *Ibid.* at 47.
14 *Ibid.* at 102-109.
15 *Ibid.* at 107. The NEB news release regarding approval of Keystone XL indicates that "[t]his … condition was fully accepted by TransCanada and reflects Canadians' evolving interest and expectations regarding Canada's pursuit of a sustainable energy future": NEB, News Release, 10/06, "National Energy Board Approves Keystone XL Pipeline Project" (11 March 2010).
16 *Keystone*, *ibid.* at 7-9.
17 *Ibid.* at 17-18.
18 See, for example, the views of the Keystone XL Shippers Group: *ibid.* at 15.

Suncor Energy Marketing Inc. (Suncor) requested that the NEB either deny or delay approval of Keystone XL, arguing in part that Keystone XL would create unnecessary excess capacity. Enbridge challenged the need for additional pipeline capacity, citing in part the potential impact that additional capacity could have on TransCanada's already approved Cushing Expansion Project. In support, Enbridge argued that forecasters were predicting a much slower rate of growth in western Canadian crude production and that there had been dramatic changes to the economic environment since the summer of 2008 when Keystone conducted its open season.[19] While the Board accepted that there may be some excess capacity from the WCSB, it found that the proposed design of Keystone XL reflected a reasonable balance for both current and anticipated requirements and further concluded that no excess capacity existed to the USGC. In determining that Keystone XL was needed, the Board considered the long-term transportation agreements, which it relied on as a demonstration of industry support and evidence of a significant financial commitment to the pipeline.[20]

c. Competition and Consideration of Commercial Impacts

The Keystone XL application was seen by Keystone as being "about competition and new market access" to the USGC.[21] One of the issues identified in the NEB's hearing order was the potential commercial impacts of Keystone XL.[22] In this regard, the NEB considered potential impacts on competition and netback prices; potential impacts to existing pipeline infrastructure; and potential impacts on the refining industry.[23]

In previous decisions, the NEB has held that "the public interest is served by allowing competitive forces to work, except where there are costs that outweigh the benefits."[24] While the Board recognized that lower netbacks could result in the short term if Keystone XL were approved and constructed, it was of the view that, in the longer term, Keystone XL would help to ensure that there was adequate capacity to connect WCSB supply to the USGC market and to "ensure that all producers realize netbacks that reflect the full market value for their production."[25] Further, while the Board acknowledged that there could be excess capacity for a period of time and that existing infrastructure could be offloaded resulting in increased tolls for shippers, it found that there was no cogent evidence demonstrating that such costs would not be manageable by the industry parties.[26] Further, the evidence did not convince the Board that Keystone XL would deter investment in upgraders or refineries in Canada, and noted that no refiners or upgraders opposed Keystone XL on the basis that it would undermine their Canadian operations.[27]

Enbridge stated that it had been approached by the Canadian Association of Petroleum Producers (CAPP) to assess whether existing pipeline capacity (that is, the Canadian portion of Enbridge Clipper) could be used as part of Keystone XL. This option was referred to

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19 *Ibid.* at 15-16.
20 *Ibid.* at 17-18.
21 *Ibid.* at 19.
22 *TransCanada Keystone Pipeline GP Ltd. — Keystone XL Pipeline,* NEB Hearing Order OH-1-2009 (12 May 2009) at 16.
23 *Keystone, supra* note 10 at 19.
24 *Ibid.* at 32.
25 *Ibid.* at 33.
26 *Ibid.*
27 *Ibid.* at 34.

during the proceedings as the "Gretna Option." While Keystone indicated a willingness to explore such options, it stated several key threshold issues with the Gretna Option, including delayed in-service timing and increased transit times, and further stated that it was not prepared to respond to concepts or negotiate such concepts in a regulatory proceeding.[28] The NEB was of the view that there was insufficient evidence to demonstrate that existing infrastructure could be incorporated into Keystone XL, or that such an option was practical. The NEB stated that the Gretna Option was not developed to the point of approaching commercial reality and concluded that a project that otherwise meets the requirements of s. 52 of the *NEB Act* "should not be denied on the basis that there might be other potential options that could be developed in the future," and that to do so would unnecessarily impede competition and the operation of the market and would not be in the public interest.[29]

d. Consultation and First Nations Impacts

The Keystone XL application made statements indicating that landowners did not have outstanding or unresolved concerns. However, during the proceeding, evidence suggested that certain residents and landowners continued to have concerns with the project and that the statements in the Keystone XL application regarding no outstanding concerns were based on Keystone's hope that continuing negotiations would resolve the concerns. The NEB confirmed its expectation that information in an application be accurate at the time it is submitted to the Board and should not be based on how an applicant anticipates matters may be resolved. Further, having regard to what the Board found to be a lack of meaningful dialogue with certain stakeholders, the Board imposed a condition directing that Keystone maintain and file with the Board, upon request, "consultation and complaint monitoring reports."[30]

Although the NEB found generally that Keystone's Aboriginal consultation program was satisfactory, the Board included a condition that would require Keystone to continue to consult and provide the Board with an update on its consultation activities.[31]

Following the issuance of the Board's hearing order, issues were raised by counsel for the Sweetgrass and Moosomin First Nations (SFN and MFN, respectively) respecting the Crown's duty of consultation. These issues culminated in a 3 September 2009 letter from counsel for the SFN and MFN stating the intention of these First Nations to file a motion to raise a preliminary matter at the beginning of the hearing seeking to adjourn the proceeding pending "the fulfillment of meaningful consultation between the federal and provincial Crown."[32]

The NEB advised in a letter decision dated 9 September 2009 that it would render its decision on the motion during the proceeding, but prior to Keystone's panel 3 being called upon for cross-examination, which was the only panel proposed to be cross-examined by

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28 *Ibid.* at 29.
29 *Ibid.* at 33-34.
30 *Ibid.* at 60, 108.
31 *Ibid.* at 68, 107.
32 *Ibid.* at 90. The Board considered the September letter a s. 35 motion under the *National Energy Board Rules of Practice and Procedure, 1995*, S.O.R./95-208, and addressed it through a written process (at 88).

counsel to the SFN and MFN. The Board considered that prejudice would be caused to parties who were prepared to proceed with the hearing and did not consider that a ruling on the motion was required prior to the start of the hearing.[33]

On 11 September 2009, the SFN and MFN filed a written notice of motion requesting: (1) "a Declaration that the NEB does not have jurisdiction to issue a section 52 Certificate until meaningful consultation has occurred"; (2) an adjournment of any hearing until fulfillment of meaningful consultation; and (3) "a Declaration clarifying the role of the NEB as either an agent of the Crown, delegated with the duty to consult, or a tribunal tasked with assessing the adequacy of the Crown's duty to consult."[34]

By letter dated 18 September 2009, three days into the oral portion of the hearing, the NEB denied the relief sought by the SFN and MFN. While the Board confirmed that potential impacts on Aboriginal rights are relevant to the Board's deliberations, relying on the Federal Court decision in *Brokenhead Ojibway Nation v. Canada (A.G.)*,[35] the Board held that its jurisdiction is to determine whether a project meets the requirements of the *NEB Act*. It is the Crown that must determine the nature and extent of the consultation obligation and the adequacy of Crown consultation. While the Crown may rely on the NEB process as a means to meet its consultation obligations, this is not a delegation to the NEB of the Crown's duty. Rather, the Board is an independent tribunal.[36] In this regard, the NEB denied the request for an adjournment pending "the fulfillment of meaningful consultation between the federal and provincial Crown,"[37] stating as follows:

> Accordingly, it would make no sense to adjourn the present hearing since the NEB hearing process is the primary means of ensuring that Aboriginals' concerns about the project are identified, considered and addressed. If, after the conclusion of the hearing the Crown is of the view that additional consultation is required, it will no doubt take appropriate steps at that time.[38]

e. Consideration of Upstream and Downstream Impacts and Project Related Greenhouse Gases

Sierra Club Canada (Sierra Club) argued that impacts from both upstream oil sands and downstream refining ought to have been, but were not, considered by Keystone in its assessment of cumulative impacts for Keystone XL. Further, Sierra Club questioned whether Keystone had adequately quantified and analyzed emissions associated with Keystone XL.[39]

Rejecting the majority of Sierra Club arguments, the NEB confirmed that it would not consider the upstream or downstream facilities either under the *NEB Act* or *CEAA*, given that Keystone was not applying for oil sands or refining facilities and that such facilities would be regulated by other governments and operated by other companies.[40] In relation to the

33 *Keystone*, *ibid.* at 88.
34 *Ibid.* at 91.
35 2009 FC 484, 345 F.T.R. 119 [*Brokenhead Ojibway*].
36 *Keystone*, *supra* note 10 at 94-97.
37 *Ibid.* at 98.
38 *Ibid.* at 97.
39 *Ibid.* at 72-73.
40 *Ibid.* at 74.

CEAA, the Board noted that "there is nothing in the [*CEAA*] to suggest that it is within the intent or ambit of that Act for a project-specific [environmental assessment] to require a broad assessment of a whole industrial sector even if aspects of it are indirectly related to the project in some fashion."[41] Further, although the Board held that it may consider specific effects from other projects in terms of cumulative effects, it found that the effects of Keystone XL would not cumulate with others and that residual emissions would not be sufficient to contribute to climate change effects.[42] While the Board was not convinced that greenhouse gas emissions would be material, it included, as a condition of the approval, that Keystone conduct a quantitative assessment of emissions to confirm the assumption that there would be negligible emission volumes and rates.[43]

2. NEB APPLICATION GH-2-2009: *DAWN GATEWAY PIPELINE GENERAL PARTNER INC.: APPLICATION FOR DAWN GATEWAY PIPELINE*[44]

Westcoast Energy Inc. (Spectra) and DTE Pipeline Company formed a partnership called the Dawn Gateway Pipeline Limited Partnership (Dawn Gateway). Its general partner applied on 6 May 2009 pursuant to ss. 58 and 74 of the *NEB Act* for authorization to purchase two portions of existing pipeline segments and to construct 17 km of new pipeline. The existing lines were the NEB regulated St. Clair Pipelines Ltd. (SCPL) St. Clair River Crossing Line from the international border across the St. Clair River, and the Union Gas Limited (Union) St. Clair Line, which is regulated by the Ontario Energy Board (OEB) and which connected the NEB regulated St. Clair River Crossing Line to Union's Bickford Compressor Station. The new-build 17 km portion of the pipeline was proposed between the Bickford and Dawn Compressor Stations. In essence, the resulting pipeline would consist of approximately 34 km of new and existing pipeline from the international border in the St. Clair River to the Dawn Compressor Station in Lambton County, Ontario.

Initially, the application also requested, pursuant to s. 58 of the *NEB Act*, exemptions from the requirements of ss. 31(c), (d), and 33 of the *NEB Act* regarding the submission of a plan, profile, and book of reference (PPBoR).[45] In essence, Dawn Gateway proposed that it would file general routing information on the basis that further work was required regarding environmental information and review of the proposed route with landowners. The Board's view on the requested exemption was noted in a 11 June 2009 letter, stating that the request for exemption "creates an expectation that the applicant has identified a specific route for the pipeline, one that has been the focal point for, and is the end product of refinements based on, detailed studies and landowner consultations."[46] However, the application filed by Dawn Gateway only provided a *general* route for the pipeline, partly because some landowners had refused the company access to their lands to complete the environmental work necessary to determine a specific route. Therefore, landowners had not, at the time the application was

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41 *Ibid.*
42 *Ibid.* at 75.
43 *Ibid.* at 107.
44 *Dawn Gateway Pipeline General Partner Inc.: Application for Dawn Gateway Pipeline*, NEB Application GH-2-2009 (6 May 2009).
45 *Ibid.* at 5.
46 Letter from Claudine Dutil-Berry, Secretary, NEB to Patricia Planting, Dawn Gateway & L.E. Smith, Counsel, Dawn Gateway, "Dawn Gateway Pipeline General Partner Inc.'s (Dawn Gateway GP) Applications Pursuant to Sections 58 and 74 of the National Energy Board Act, dated 6 May 2009" (11 June 2009) at 1.

filed with the NEB, been provided notice of the specific route and had not had an opportunity to engage in related discussions with the company. The Board found the application deficient and requested further information from the applicant. In particular, the Board required that Dawn Gateway consult with directly affected landowners and requested that Dawn Gateway either provide a specific pipeline routing or agree to file a PPBoR application in the event the Board approved the application.[47] While Dawn Gateway withdrew the PPBoR exemption request,[48] several landowners continued to refuse access to their lands for Dawn Gateway to complete environmental and other surveys. Dawn Gateway ultimately reinstated its exemption request.

a. The GAPLO and Dawn Gateway Motion

The survey access issue eventually came to a head in two pre-hearing motions. GAPLO-Union and the Canadian Association of Energy and Pipeline Landowner Associations, which represented various landowners, filed a motion on 9 September 2009 requesting a stay of the Board's consideration of the application.[49] Subsequently, on 21 September 2009, Dawn Gateway filed a notice of motion requesting that the Board issue orders pursuant to ss. 12 and 13 of the *NEB Act* directing that certain landowners comply with s. 73(a) of the *NEB Act*. The Dawn Gateway motion requested permission for Dawn Gateway to temporarily access certain lands for the purposes of completing environmental, archaeological, and geotechnical surveys and investigations required to provide information to the Board that was necessary for the Board to approve the route of the pipeline.[50] Further, the motion requested an order forbidding certain landowners from denying or obstructing Dawn Gateway's temporary access to the lands for those purposes. After considering subsequent submissions, the Board ruled in favour of Dawn Gateway in both instances.[51]

The GAPLO motion was premised on an application that was before the OEB with respect to the sale of the Union St. Clair Line from Union to Dawn Gateway.[52] The GAPLO motion asserted that the OEB's consideration of jurisdictional issues related to the regulation of the Union St. Clair Line necessitated that the NEB stay its consideration of the NEB

47 *Ibid.* at 2.

48 Letter from L.E. Smith, Counsel, Dawn Gateway to Claudine Dutil-Berry, Secretary, NEB, "Dawn Gateway Pipeline General Partner Inc.'s (Dawn Gateway GP) Applications Pursuant to Sections 58 and 74 of the National Energy Board Act, dated 6 May 2009" (12 June 2009).

49 *Dawn Gateway General Partner Inc.: Application for Dawn Gateway Pipeline* (Notice of Motion by GAPLO-Union (Dawn Gateway) and Canadian Association of Energy and Pipeline Landowners Associations), NEB Application GH-2-2009 (9 September 2009) [*Dawn Gateway*, "GAPLO motion"].

50 *Dawn Gateway General Partner Inc.: Application for Dawn Gateway Pipeline* (Notice of Motion by Dawn Gateway for Temporary Access to Certain Lands), NEB Application GH-2-2009 (21 September 2009) at para. 1 [*Dawn Gateway*, "Dawn Gateway motion"].

51 The Board ruled on the request for a stay and the request for temporary access: see letter from Anne-Marie Erickson, Acting Secretary, NEB to various parties, "Dawn Gateway Pipeline General Partner Inc. (Dawn Gateway GP): Application for Dawn Gateway Pipeline dated 17 July 2009 — GAPLO/ CAEPLA Notice of Motion to Stay the Board's Consideration of the Dawn Gateway GP Application, Dawn Gateway GP Notice of Motion for Orders Pursuant to section 73 of the *National Energy Board Act*, GAPLO/CAEPLA Counter-Motion for Service of section 87 Notices" (21 October 2009) [NEB, "21 October 2009 letter"].

52 *Union Gas Limited: Leave to Sell 11.7 Kilometers Natural Gas Pipeline*, OEB Notice of Application and Hearing EB-2008-0411 (3 February 2009). In April 2009, the OEB indicated that it would examine the jurisdiction of the proposed pipeline: *Union Gas Limited: Leave to Sell 11.7 Kilometers of Natural Gas Pipeline*, OEB Decision and Order EB-2008-0411 (6 April 2009) at 4. All OEB decisions, and the documents pertaining to them, can be found online: OEB <http://www.oeb.gov.on.ca/OEB/Industry>.

application.[53] In a letter decision regarding the motions, the Board agreed that there was a serious issue (that is, jurisdiction) to be considered.[54] However, the Board held that determining the jurisdictional issue was based not only on "where the matter was first seized," but should also consider which action is more comprehensive, whether issuing a temporary stay would "prevent unnecessary duplication of proceedings," and whether the stay would "result in an injustice to the party resisting the stay." The Board denied the stay, relying in part on the right of the applicant "to have its application heard in a timely manner."[55]

Dawn Gateway's motion was filed pursuant to ss. 12, 13, and 73 of the *NEB Act*. Section 73 of the *NEB Act* identifies the powers of a pipeline company, providing the company with the ability to enter on the land of any person to make surveys, examinations, or necessary arrangements for fixing the site of the pipeline.[56] If the requested relief was granted, certain landowners would be required to provide Dawn Gateway with temporary access to lands such that Dawn Gateway could exercise its rights pursuant to s. 73 of the *NEB Act*.

In its letter decision of 21 October 2009, the Board held that "[t]he purpose of [s.] 73(a) is to allow a company to meet the necessary information requirements" for an application.[57] In particular, s. 73 allows a pipeline company to conduct surveys and examinations that would be required in order for the Board to make a decision under the *CEAA* and grants to the pipeline company "the right to enter lands, without agreement of the landowner, to conduct surveys and examinations necessary for regulatory purposes."[58] In conjunction with this finding, the Board held that a right of entry application pursuant to s. 104 was not a prerequisite to exercising the rights under s. 73. Rather, the Board reasoned that "the purpose of section 73 is to modify the law of trespass by removing the common-law requirement of consent," and that "[i]f a right of entry order [pursuant to s. 104] was required, there would be no need for section 73."[59]

b. Public Hearing Process

While the NEB initially determined that the application would be considered through the Board's non-hearing procedures, on 6 November 2009 the Board announced that it would hold a public hearing on the application.[60] The hearing was scheduled to commence on 23 February 2010. As part of the process, the NEB would examine whether the project should

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53 *Dawn Gateway*, "GAPLO motion," *supra* note 49 at paras. 33-34. See also *Dawn Gateway Pipeline Limited Partnership*, OEB Decision and Order EB-2009-0422 (9 March 2010) at paras. 7-8 [*Dawn Gateway*], discussing *Union Gas Limited — Leave to Sell 11.7 Kilometers of Natural Gas Pipeline*, OEB Decision and Order EB-2008-0411 (27 November 2009) [*Union Gas*], regarding the OEB's assertion of jurisdiction over the Union St. Clair Line.

54 NEB, "21 October 2009 letter," *supra* note 51. The Board noted that given its determination, the other "tests" of a stay did not have to be considered, but if they had been, the Board would have found that there was no irreparable harm and the balance of convenience favoured the applicants (at 4).

55 *Ibid.*

56 *NEB Act*, *supra* note 4.

57 NEB, "21 October 2009 letter," *supra* note 51 at 6.

58 *Ibid.*

59 *Ibid.* at 7.

60 *Dawn Gateway Pipeline General Partner Inc. (Dawn Gateway GP): Dawn Gateway Pipeline Application of 6 May 2009*, NEB Hearing Order GH-2-2009 (6 November 2009).

be subject to federal jurisdiction.[61] Therefore, the NEB issued a notice of constitutional question on 22 October 2009 setting out the process for examination of the issue.[62]

While the NEB fully briefed the contending jurisdictional positions, it never rendered a decision. The OEB, in the context of considering the application by Union for leave to sell the Union St. Clair Line to Dawn Gateway, asserted, *inter alia*, jurisdiction over the new-build Bickford-Dawn Line and Union's St. Clair Line but not the NEB regulated SCPL line, despite the fact that the proposed transportation service solely involved an international service from the U.S. border to Union's Dawn Compressor Station.[63] As a result, in a letter dated 4 December 2009, Dawn Gateway wrote to the NEB and withdrew its application for the Dawn Gateway pipeline and requested that the hearing process be terminated, stating that the "project [could not] sustain the cost, uncertainty and delay associated with the jurisdictional impasse that has arisen as a result of the OEB's ruling in a Union Gas application to sell a surplus pipeline asset."[64] As a result, the Board terminated the process and cancelled the hearing, thereby precluding the need for the Board to issue a ruling on jurisdiction.

3. NEB DECISION GH-1-2009: *NOVA GAS TRANSMISSION LTD.: FACILITIES APPLICATION*[65]

By application dated 30 April 2009, NOVA Gas Transmission Ltd. (NGTL) applied to the NEB requesting approval pursuant to s. 52 of the *NEB Act* for a certificate of public conveyance and necessity (CPCN) for the Groundbirch Pipeline.[66] NGTL did not request a determination for tolling methodology pursuant to Part IV of the *NEB Act*. In this regard, the Board confirmed that tolls and tariffs would need to be approved by the Board before the pipeline is placed in service.[67] The NEB set 17 November 2009 as the commencement date for the hearing, the oral portion of which was completed on 19 November 2009 in Dawson Creek, British Columbia.

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61 *Ibid.* at 5.

62 Letter from Anne-Marie Erickson, Acting Secretary, NEB to Patricia Planting, Dawn Gateway & L.E. Smith, Counsel, Dawn Gateway, "Dawn Gateway Pipeline General Partner Inc. (Dawn Gateway GP): Application for Dawn Gateway Pipeline dated 17 July 2009 — Notice of Constitutional Question" (22 October 2009).

63 See *Union Gas, supra* note 53 at 14.

64 Letter from Bruce E. Pydee, Director, Dawn Gateway to Anne-Marie Erickson, Acting Secretary, NEB, "Dawn Gateway Pipeline General Partner Inc. (Dawn Gateway GP): Application for Dawn Gateway Pipeline dated 6 May 2009, NEB File No. OF-Fac-Gas-D159-2009-01 01, Hearing Order GH-2-2009 — Request to Terminate the GH-2-2009 Proceeding" (4 December 2009).

65 *Nova Gas Transmission Ltd.: Facilities Application*, NEB Decision GH-1-2009 (March 2010) [*Groundbirch*].

66 The Board denied a request by CAEPLA and the South Peace Landowners Association (SPLA) for the project to be referred to a review panel pursuant to ss. 25 and 28 of the *CEAA*, *supra* note 9. Rather, the NEB proceeded with a screening of the project, stating that "the Board is required to conduct a screening level environmental assessment … and to hold a public hearing. The Board is satisfied that its hearing process will provide an opportunity for members of the public to raise concerns relevant to the environmental assessment and all matters within the Board's jurisdiction": letter from Anne-Marie Erickson, Acting Secretary, NEB to David R. Core, Chairman, CAEPLA & Kane Piper, President, SPLA, "Nova Gas Transmission Ltd. (NGTL): Groundbirch Pipeline Project (Project), GH-1-2009 — Request to Refer the Groundbirch Pipeline Project to a Review Panel" (21 August 2009) at 1.

67 *Groundbirch*, *supra* note 65 at 49.

a. Project Description and NEB Findings

Groundbirch was the first opportunity for the NEB to hold a proceeding in respect of new facilities for the Alberta System following the NEB's assumption of federal jurisdiction over the TransCanada Alberta System in 2009.[68] The proposed pipeline would be approximately 77 km of 36-inch pipeline and related facilities, extending the TransCanada Alberta System to connect unconventional and conventional sweet natural gas supply in northeast British Columbia.

Noting its statutory mandate pursuant to s. 52 of the *NEB Act* to determine whether requested facilities will be required by present and future public convenience and necessity and, therefore whether approval would be in the public interest, the Board described the "public interest" as follows:

> The public interest is inclusive of all Canadians and refers to a balance of economic, environmental and social interests that change as society's values and preferences evolve over time. As a regulator, the Board must estimate the overall public good a project may create against its potential negative aspects, weigh its various impacts, and make a decision.[69]

b. Economic Feasibility

No interveners challenged NGTL's forecasts of supply, the adequacy of markets, NGTL's evidence regarding transportation and throughputs, or its ability to finance the project. Based on the evidence, the Board concluded that the project was needed and would be economically feasible.[70]

c. Natural Gas Liquid Matters

While interveners, including BP, generally supported the project, the Board was urged by BP and NOVA Chemicals to address issues related to the natural gas liquid (NGL) content of the gas to be transported. While NGTL acknowledged that the gas would have a component of NGL, it did not conduct a detailed NGL analysis.[71] Talisman supported NGTL's approach, stating that in its view gas streaming "should not be an issue" in the proceeding and was not a matter appropriate to be considered in the Board's deliberations regarding the public convenience and necessity of the pipeline.[72]

BP took a different view regarding the relevance of gas analysis. In final argument, BP submitted that "[b]oth the need for and scope of an NGL analysis and the commitment and policy position on rich/lean gas streaming fundamentally go to the question of design of the

68 *TransCanada PipeLines Limited: Jurisdiction and Facilities*, NEB Decision GH-5-2008 (February 2009) at 9.
69 NEB, *Information Series: Pipeline Regulation in Canada — A Guide for Landowners and the Public*, (Calgary: NEB Publications Office, 2003) at 21, as cited in *Groundbirch*, *supra* note 65 at 2.
70 *Groundbirch*, *ibid.* at 8.
71 *Ibid.* at 9.
72 *Ibid.* at 9-10.

system."[73] While BP was neither opposing the application nor asking the Board to condition approval on matters related to NGL, BP requested that the Board "expressly find that NGL impacts" were to be considered as "an element of the public interest" not only with respect to the particular proceeding before the Board, but also as part of the public interest determination in any significant future facilities additions.[74] BP further requested that the Board direct NGTL to create a detailed NGL analysis policy.[75] Board Member Georgette Habib noted in questions to counsel for BP during final argument the scarcity of the evidence in the proceeding with respect to NGL analysis and associated matters.[76]

While the Board acknowledged the complexities of NGL extraction in *Groundbirch*, it was not persuaded that addressing NGL-related issues, such as "a detailed analysis of NGL content on the Alberta System, or a detailed assessment of the impact of the Project on the NGL industry," was required in order for the Board to make its public interest determination.[77]

d. Landowner and First Nation Consultation

The Board noted general satisfaction with NGTL's landowner and First Nation consultation program.[78] However, concerns were raised by SPLA regarding NGTL's use of a confidentiality agreement (CA) and the impact of that agreement on the consultation process.[79] While NGTL acknowledged that improvements could be made to the consultation process, in order to enhance long-term relationships with landowners NGTL had proposed cooperation agreements and associated CAs intending to prevent disclosure of agreement terms to NGTL's competitors.[80] SPLA suggested that its members had difficulty understanding the CAs and had received contradictory advice from NGTL regarding interpretation of the provisions. Further, SPLA argued that providing the CAs to landowners, together with the s. 87 notices, suggested that the CAs had been approved by the NEB.[81] While the NEB appeared to accept as valid NGTL's intentions in proposing the CAs, the Board was of the view that the introduction of the CAs frustrated the very purpose (that is, enhancement of long-term relationships) for which they were introduced. The Board encouraged the parties to continue consultations to discuss outstanding concerns and seek mutually agreeable solutions.[82]

The Duncan's First Nation (DFN) and Horse Lake First Nation (HLFN) provided oral statements at the hearing, including oral evidence from elders, raising concerns respecting the adequacy of consultation, accommodation, mitigation, and traditional use interests.[83] DFN requested that the Board expand its consultation requirements to include socio-

73 *Groundbirch*, "Transcripts: Hearing GH-1-2009 — Facilities," vol. 3 (19 November 2009) at para. 4193 (Final Argument, Mr. Brett).
74 *Ibid.* at para. 4205.
75 *Ibid.* at para. 4212.
76 *Ibid.* at para. 4248.
77 *Groundbirch, supra* note 65 at 10.
78 *Ibid.* at 23.
79 *Ibid.* at 22-23.
80 *Ibid.* at 22.
81 *Ibid.*
82 *Ibid.* at 23.
83 *Ibid.* at 24-34.

economic matters and recommended that if NGTL was allowed to cross its traditional territory as proposed, NGTL should be required to adopt a "no net loss" approach to mitigation planning, which would involve reclaiming equivalent portions of other areas, in order to provide suitable habitat conditions.[84] While there was insufficient evidence on this latter point to assess its practical feasibility, the Board noted that it was an innovative approach "that NGTL could productively explore in further consultation with DFN."[85]

The Board also denied DFN's request to expand the scope of consultation to encompass socio-economic matters. Indeed, the Board found that the consultation requirements were already quite broad and included components of socio-economic impacts.[86] Further, despite concerns of the DFN and HLFN regarding potential impacts of the project, the Board relied on NGTL's proposed mitigation measures, procedures, and commitments to consider additional concerns of the First Nations, as well as the Board's recommendations respecting environmental protection measures and a traditional land use report, to conclude that impacts to lands used for traditional purposes would be effectively mitigated.[87] Even so, the Board determined that it would condition any certificate to require that NGTL provide further information on habitat restoration as a means to further mitigate impacts on traditional uses.

In respect of the routing concerns raised by the two First Nation groups, the NEB confirmed that the s. 52 hearing was not the appropriate forum in which to assess the best possible detailed route for the pipeline. Moreover, the Board was not convinced that either of the two general alternate routes proposed by DFN was preferable to NGTL's general route and was therefore not prepared to reject NGTL's general route as proposed.[88]

e. Cumulative Effects

During the oral hearing, DFN requested that the NEB hold a meeting with government representatives, First Nation groups, and project proponents respecting cumulative effects.[89] The Board dismissed the request on the basis of procedural fairness, citing in part the lateness of the request and the absence of any evidence suggesting that the First Nation had solicited others' views regarding the meeting request. The Board also noted that there was no indication respecting how such information could be used in the Board's assessment of the project. Despite the Board's view that the cumulative effects assessment already conducted was sufficient, having regard to the increased awareness and demand for such information, the Board encouraged consultation on the issue and continued improvement in cumulative effects assessments related to proposed projects.[90]

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84 *Ibid.* at 28, 31.
85 *Ibid.* at 39-40.
86 *Ibid.* at 32.
87 *Ibid.* at 33-34.
88 *Ibid.* at 39.
89 *Ibid.* at 45.
90 *Ibid.* at 45-46.

f. Facilities — Post Construction Integrity Validation

Section 4 of the *Onshore Pipeline Regulations, 1999*[91] requires that companies comply with the Canadian Standard Association's (CSA) *CSA Z662-07, Oil and Gas Pipeline Systems*,[92] which in turn requires that all pipelines undergo pressure testing before being placed into operation. The Board noted that alternative integrity validation (AIV) has previously been proposed as one way to determine whether a pipeline has the integral strength to withstand operating pressure prior to being put in service, and that the Board had previously granted a waiver in respect of the hydrostatic testing requirements in one case regarding the Deux Rivières Loop portion of TransCanada's Eastern Mainline Expansion.[93]

In its additional written evidence, NGTL requested a waiver of certain requirements relating to hydrostatic testing. Noting that NGTL's proposal for AIV was new and not recognized by existing standards as a replacement for the hydrostatic test, the Board denied the request, but left open the possibility of NGTL applying in the future for a partial exemption from the hydrostatic testing requirements and provided, in Appendix VI of the decision, minimum information requirements for such an exemption application.[94]

Procedurally, pipeline companies seeking approval of an AIV process should seek to make relevant filings at the earliest possible opportunity through pre-application meetings with the Board or otherwise, rather than late in the process in response to a Board information request days prior to the commencement of the hearing as NGTL had done. Indeed, the Board encouraged an open forum for discussion of AIV related issues through standard setting bodies or through an open and generic consideration of the issue where all interested parties have an opportunity to participate.[95]

4. NEB DECISION GH-1-2010: *WESTCOAST ENERGY INC., CARRYING ON BUSINESS AS SPECTRA ENERGY TRANSMISSION — FORT NELSON NORTH PROCESSING FACILITY APPLICATION*[96]

By application dated 4 August 2009, Westcoast Energy Inc. (Westcoast) applied to the NEB, pursuant to s. 58 of the *NEB Act*, for approval to construct and operate a new gas processing facility, including on-site generation and a 775 m all-season access road. The proposed facility would be located approximately 75 km east of Fort Nelson, British Columbia and was proposed to accommodate increased production and demand on the east side of the Horn River Basin. Westcoast also sought exemptions pursuant to s. 58 of the *NEB Act* from the requirements of ss. 30(1)(a), 30(2), and 31, as well as the s. 47 leave to open

91 S.O.R./99-294.
92 CSA, *CSA Z662-07, Oil and Gas Pipeline Systems*, 5th ed. (Mississauga: CSA, 2007).
93 *Groundbirch, supra* note 65 at 15-16. See letter from Michel L. Mantha, Secretary, NEB to Nadine Berge, Counsel, TransCanada & Ian Cameron, Regulatory Project Manager, TransCanada, "TransCanada PipeLines Limited (TransCanada) Section 58 Application for the 2006 Eastern Mainline Expansion: Hydrotesting Requirement of the Deux-Rivières Loop" (19 October 2006). In this letter, the NEB considered that the AIV process was a field trial and that in order for the AIV to progress, it would require "a demonstration that a documented and effective quality management system [was] fully implemented" (at 2).
94 *Groundbirch*, *ibid.* at 17-20, 116-17.
95 *Ibid.* at 19.
96 *Westcoast Energy Inc., carrying on business as Spectra Energy Transmission — Fort Nelson North Processing Facility Application*, NEB Decision GH-1-2010 (March 2010).

requirements. The Board granted all of the requested relief, except for the exemption from the leave to open requirements.[97]

While the Board initially determined to hold an oral public hearing, the Dene Tha' First Nation (DTFN), which was the only party to request an oral hearing, subsequently withdrew its request. As the Board received no objection to its proposal to cancel the public hearing, it proceeded to consider the application pursuant to s. 58 of the *NEB Act* without a hearing process.

The main issues considered by the Board were the need for the project; Aboriginal engagement, consultation, and participation; and environmental issues regarding regional sulphur management and greenhouse gas emissions. With respect to the first of these three issues, the Board determined that the project was "needed and would be used and useful at a reasonable level over its economic life."[98]

a. First Nation Consultation and Participation

The Board was satisfied that "all Aboriginal groups potentially affected … were provided with sufficient details about the Project."[99] Noting that Westcoast had not contacted the Northern Rockies Métis Society about the project, the NEB commented that, where appropriate, Métis and First Nations groups should be included "in the early and ongoing consultation processes related to the Project."[100] The Board expressed its view regarding the importance of continuing ongoing consultation efforts and requested that Westcoast file with the Board an Aboriginal Consultation Report and Data Update throughout the construction and initial years of operation.[101] Further, the Board expressed its intention to monitor Westcoast's economic opportunities commitment regarding the involvement of First Nations in the construction and operation of the project, thereby requiring Westcoast to file an Aboriginal Participation Report throughout construction and the initial years of operation.[102]

b. Environmental Effects

Under the *CEAA*, both environmental effects and cumulative effects are required to be examined by the Board, including the extent to which the effects from other projects would interact cumulatively with the residual effects of the project. The Board determined that the measurable SO_2 was within the environmental assessment to be conducted under *CEAA* and such a review would support "the Board's vision of a sustainable energy future."[103] The Board required that Westcoast have an ambient monitoring program in place to validate the SO_2 modelling results and an SO_2 emissions management plan in order to track monitoring results.

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97 *Ibid.* at 8.
98 *Ibid.* at 2.
99 *Ibid.* at 4.
100 *Ibid.* at 3.
101 *Ibid.* at 4.
102 *Ibid.* at 5.
103 *Ibid.*

The Board proposed that Westcoast meet with the NEB in the future to discuss the management of inlet sulphur and recovery options. While there were no federal or provincial regulations regarding acceptable greenhouse gas emission levels and mitigation or reduction strategies at the time of the hearing, the Board expected that Westcoast would have in place a project-specific environmental protection program.[104] The Board required that Westcoast submit an annual status report regarding the annual CO_2e (equivalent) emissions reported to Environment Canada and the British Columbia Minister of Environment including validation and verification.[105] While Westcoast identified two possible carbon capture options (carbon capture and storage or the use of CO_2 in enhanced oil recovery operations),[106] the Board also required that Westcoast submit further information resulting from its investigations of options for carbon capture including options for the reduction of greenhouse gas emissions.

5. CANADIAN COST OF CAPITAL MATTERS

This past year was a pivotal period in utility cost of capital matters. Virtually every Canadian jurisdiction has now concluded that returns generated by the old style formulas, such as the NEB's RH-2-94 Formula, are no longer fair and reasonable.

On 8 October 2009, the NEB issued a two-page letter decision[107] wherein it concluded that the formula-approach to the determination of a generic cost of capital for companies under its jurisdiction, which was implemented in 1994 via the *RH-2-94* decision,[108] is no longer appropriate in the existing financial environment. That decision will affect most NEB-regulated Group 1 pipelines in relation to cost of capital matters. It is now up to each individual company to demonstrate to the Board an appropriate return on equity (ROE) or to settle the issue with its shippers, subject to Board approval of the settlement agreement. The decision also appears to have impacted other companies under the jurisdiction of provincial regulators, as several jurisdictions historically relied upon a formulaic-approach that was originally modeled after the RH-2-94 Formula.

a. Background — The RH-2-94 Formula

In the *RH-2-94* decision, the NEB approved a rate of return on common equity for a low risk, high-grade benchmark pipeline at 12.25 percent (for 1995).[109] The NEB relied upon this benchmark pipeline as the standard for determining the allowed ROE for Group 1 regulated pipelines under its jurisdiction. Pursuant to this methodology, the business risk associated with each specific company was accounted for by adjustments in the equity component of the deemed capital structure. Additionally, the Board adopted a formula for adjusting the ROE on an annual basis. The RH-2-94 Formula linked the ROE to a forecast of a long-term

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104 *Ibid.* at 6.
105 *Ibid.* at 7.
106 *Ibid.* at 6.
107 *Review of the Multi-Pipeline Cost of Capital Decision (RH-2-94),* NEB Letter Decision (8 October 2009) [*Cost of Capital Review*].
108 *TransCanada PipeLines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd., Trans Québec Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd., Trans-Northern Pipeline Inc.: Cost of Captial,* NEB Decision RH-2-94 (March 1995) [*RH-2-94*].
109 *Ibid.* at 6.

Government of Canada bond yield and adjusted the ROE for 75 percent of the change in the forecasted yield.[110]

Over the past 15 years, the RH-2-94 Formula has been relied upon by the NEB to determine the allowed rate of return for most Group 1 pipeline companies, subject to certain negotiated settlements. Even settlement agreements or pipelines not governed directly by the RH-2-94 Formula most often used it as a reference point for their own ROE determinations. Many provincial regulators had followed suit over the years by implementing formulas virtually identical to the RH-2-94 Formula.

The RH-2-94 Formula has been subject to much debate and criticism from NEB-regulated pipelines, as well as those companies under provincial jurisdiction that have similar formulas. The problem is the inherent structure of the RH-2-94 Formula: namely, that it is tied to long-term Government of Canada bond yields. In essence, as long-term Government of Canada bond yields drifted in a downward direction over the past number of years, the allowed returns for regulated companies under the RH-2-94 Formula have headed in the same direction. More recently, major changes in the equity markets pointed to increased risk and return culminating in the economic crisis where observed equity returns spiked while formula driven returns moved in the opposite direction. For this reason, many pipeline and regulated companies have argued that the RH-2-94 Formula is broken.

b. The Fall of the RH-2-94 Formula — NEB Decision RH-1-2008: *Trans Québec & Maritimes Pipelines Inc.: Cost of Capital*[111]

On 19 March 2009, the NEB released its reasons for decision in *Trans Québec* wherein the RH-2-94 Formula was extensively reviewed, and ultimately abandoned, by the Board in respect of a single NEB-regulated pipeline company's 2007 and 2008 test years.

Trans Québec arose in the context of an application by Trans Québec & Maritimes Pipelines Inc. (TQM) for approval of the cost of capital to be used in calculating its final tolls for a two-year period commencing 1 January 2007 and ending 31 December 2008. In its application to the Board, TQM applied for an order approving tolls and an overall fair return on capital for the years 2007 and 2008. TQM sought alternative relief that would result either from the application of a rate of return of 11 percent to a deemed equity component of 40 percent[112] of TQM's capital structure, together with TQM's actual cost of debt,[113] or a 6.7 percent after tax weighted average cost of capital (ATWACC). In conjunction with the application, TQM also applied for a review and variance of the *RH-2-94* decision, requesting that the Board review the fair return for TQM for the two-year period, preferring the ATWACC methodology.[114]

110 *Ibid.* at 31.

111 *Trans Québec & Maritimes Pipelines Inc.: Cost of Capital*, NEB Decision RH-1-2008 (March 2009) [*Trans Québec*].

112 In line with the *RH-2-94* decision, TQM previously had a 30 percent deemed component of equity, which contributed to a weak financial profile for TQM.

113 The Board notes in *Trans Québec*, *supra* note 111 at 78-82, that when combined with actual debt costs, 9.7 percent ROE based on 40 percent equity is equivalent to the market-based ATWACC of 6.4 percent set by the Board. The ATWACC results in a higher overall return for TQM.

114 *Ibid.* at 12.

The experts for TQM provided their opinion that a more appropriate way to establish a company's required return was to focus directly on the ATWACC, which is the standard used by unregulated businesses throughout the world to evaluate potential investments. The ATWACC was said to be "the most fundamental measure of the rate of return for a given level of business risk," since it "focuses on the total return on capital" and automatically adjusts for differences in capital structure among companies.[115]

On 19 March 2009, the Board granted TQM's review and variance request in relation to the *RH-2-94* decision. The Board stated that a significant time period had passed, in the context of financial regulation, from the implementation of the RH-2-94 Formula. The Board further stated that there had been significant changes in the financial markets since 1994, as well as in general economic conditions. These changes, in the Board's view, cast doubt on some of the "fundamentals underlying the RH-2-94 Formula as it relates to TQM."[116]

The Board went on to grant TQM an aggregate return on capital, set a 6.4 percent total weighted average after tax return (compared to an approximate 5.5 percent return that would have resulted had the Board used the RH-2-94 Formula), thus leaving TQM to choose its optimal capital structure. It should be noted that the ATWACC approach had been raised in the past but had not been accepted by the NEB.[117] In *Trans Québec*, however, the Board decided to rely on the ATWACC approach for TQM's 2007 and 2008 cost of capital because the approach "is more aligned with the way capital budgeting decision making takes place in the business world."[118] The NEB also stated that the ATWACC approach enables better comparisons of return on capital for companies of similar risk. The decision found that the comparable return standard was met and agreed that U.S. utilities were comparable in risk to TQM for the purpose of the fairness analysis.[119]

The *Trans Québec* decision represents the first time that ATWACC has been adopted for determining the allowed rate of return for regulated companies and the beginning of the end of the NEB's RH-2-94 Formula.

c. Confirmation that the RH-2-94 Formula is No Longer Valid — NEB Letter Decision: *Review of the Multi-Pipeline Cost of Capital Decision (RH-2-94)*[120]

After the review and variance was granted to TQM for the 2007 and 2008 test years, the NEB considered it appropriate to initiate a more widespread review of the appropriateness of the RH-2-94 Formula for all NEB-regulated pipelines. After hearing from a broad range of interested parties on the applicability of the RH-2-94 Formula, the NEB issued its *Cost of Capital Review* decision. In the decision, the NEB concluded that there was substantial

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115 *Ibid.*
116 *Ibid.* at 16.
117 See *TransCanada PipeLines Limited: Cost of Capital*, NEB Decision RH-4-2001 (June 2002), wherein the NEB highlighted numerous shortcomings associated with an ATWACC approach. The NEB noted, and TCPL acknowledged that, at that time, the ATWACC methodology had not been adopted by any regulatory body in North America (at 40).
118 *Trans Québec*, *supra* note 111 at 18.
119 *Ibid.* at 68.
120 *Supra* note 107.

"doubt as to the ongoing correctness of the RH-2-94 Decision."[121] In reaching its decision, the Board stated that the length of time that the RH-2-94 Formula had been in effect (15 years) was significant in the context of financial regulation. The NEB also noted that there had been "considerable changes in the financial and economic circumstances" over the past 15 years.[122]

On 8 November 2009, CAPP (which represents companies that explore for, develop, and produce natural gas and crude oil) and the Industrial Gas Users Association (IGUA), a trade association that represents industrial companies who consume natural gas in their industrial operations, filed a leave to appeal application at the Federal Court of Appeal in relation to the NEB's *Cost of Capital Review* decision. CAPP and IGUA argued that the NEB's *Cost of Capital Review* should be rendered void *ab initio* because the Board "failed to meet the duty of procedural fairness and natural justice required of it in the circumstances."[123] CAPP and IGUA's leave to appeal was dismissed, however, by the Federal Court of Appeal on 18 March 2010. As a result, NEB-regulated pipelines are now free to propose new ROEs to settle the issue with shippers presumably using the higher TQM award as a reference point relative to the RH-2-94 Formula.

d. Alberta Utilities Commission Decision 2009-216: *2009 Generic Cost of Capital*[124]

On 12 November 2009, the Alberta Utilities Commission (AUC) issued its *Cost of Capital* decision for electric, gas, and pipeline utilities under its jurisdiction. The decision followed an extensive proceeding that lasted over 15 months and included 21 days of oral testimony. As well, there were five AUC members (as opposed to the traditional three) that presided over the proceeding — signifying the importance of the decision.

Close on the heels of the NEB confirming its earlier determination in *Trans Québec* that its own ROE Formula was broken, the AUC appeared to arrive at the same conclusion. It rejected the continued use of the EUB's 2004-052 Formula (the EUB Formula), which had been established five years earlier.[125] The EUB Formula had been modeled closely after the NEB's RH-2-94 Formula. Appearing to agree with utilities who were unanimous in their view that "the [EUB formula] is broken,"[126] the AUC concluded:

> Because of the way the formula had been designed, it was not capable of adjusting for the unexpected changes in the relationship that occurred in the capital markets, as a result of the financial crisis. The formula produced results for 2009 that were not correlated with market movements.[127]

121 *Ibid.* at 2.
122 *Ibid.*
123 Court action No. 00172, Memorandum of Fact and Law of the Applicants (CAPP and IGUA) (8 November 2009) at 1-2.
124 *2009 Generic Cost of Capital*, AUC Decision 2009-216 (12 November 2009) [*Cost of Capital*]. All AUC decisions, and the documents pertaining to them, can be found online: AUC <http://www.auc.ab.ca/Pages/Default.aspx>.
125 *Generic Cost of Capital*, EUB Decision 2004-052 (2 July 2004), online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2004/2004-052.pdf>.
126 *Cost of Capital*, *supra* note 124 at para. 415.
127 *Ibid.* at para. 417.

The AUC appears to have disagreed with interveners' arguments that the "financial markets are healing."[128] Indeed, the AUC rejected intervener suggestions that the EUB Formula simply be suspended for one year until a return to normal capital markets:

> [T]he Commission is not prepared to simply re-impose the same formula or any formula without a careful assessment of changes in the capital markets and a reconsideration of the types of factors that should be built into a formula.[129]

Accordingly, the AUC set a generic ROE of 9 percent for both 2009 and 2010 and further ordered an interim 9 percent ROE for 2011, at which time a new proceeding will be initiated to revisit the level of the fair return for 2011. In arriving at its 9 percent ROE award, the AUC affirmed the Fair Return Standard but, unlike the NEB and OEB, rejected the comparability of U.S. returns.[130] The AUC relied on some of the capital asset pricing model and discontinued cash flow results to form the primary basis for its ROE determination. It supplemented the increased ROE award, however, with increases in equity thickness for all the utilities on the grounds that "[t]he credit crisis warrants an increase in the equity ratios for all utilities to reflect increased risk and the re-pricing of risk."[131] Thus, the AUC ROE award cannot be viewed in isolation from the increased equity ratios also awarded.

Unlike the NEB, the AUC chose to continue a "generic" approach to establishing the ROE for all utilities under its jurisdiction. Exactly what will happen in 2011 is difficult to assess at this time, as the AUC has left it open to pursue any option for establishing the ROE at that point.[132]

e. OEB Decision EB-2009-0084: *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*[133]

On 11 December 2009, the OEB released its much-anticipated cost of capital decision. The OEB's decision impacts the rate of return for Ontario utilities for the 2010 rate year (commencing 1 January 2010).

Similar to the AUC, the OEB had in place a formulaic approach to setting the ROE that was modelled after the RH-2-94 Formula (the OEB Formula). While the OEB determined that it was appropriate to maintain the formulaic approach, it also rejected the NEB's RH-2-94 Formula. The OEB held that fairness required a resetting of the OEB Formula in order to address the relatively low current ROE level and to reduce the sensitivity to changes in Government of Canada bond yields.[134] Specifically, the OEB Formula, which would have produced ROEs for 2010 of ~8.39 percent, was reset to the forecast long-term Government of Canada bond yield plus a 5.50 percent equity risk premium. Assuming a forecast long-term Government of Canada bond yield of 4.25 percent, the OEB's reset formula will

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128 *Ibid.* at para. 418.
129 *Ibid.* at para. 422.
130 *Ibid.* at paras. 188-205.
131 *Ibid.* at para. 411.
132 *Ibid.* at para. 424.
133 *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, OEB Decision EB-2009-0084 (11 December 2009).
134 *Ibid.* at 32-33.

produce an ROE for Ontario utilities of 9.75 percent (for rates effective 1 January 2010).[135] The OEB, like the NEB, but in contrast to the AUC, held that returns enjoyed by U.S. utilities were relevant to its ROE determination given the similarity in risks.

In addition, the OEB made a number of changes to the manner in which the costs of long-term and short-term debt are to be determined for Ontario utilities. In particular, the OEB stated that the method used to determine the long-term cost of debt for electricity distributors should evolve over time so as to mirror the process used for natural gas distributors. Currently, electricity distributors use an OEB-deemed long-term cost of debt (irrespective of a distributor's actual cost of debt). In contrast, natural gas distributors utilize a weighted cost of embedded debt.[136]

Finally, it is noteworthy that the OEB did not alter the capital structure of the Ontario utilities. In the OEB's view, the capital structures continue to be appropriate at this time (wherein electricity distributors have a 40 percent debt and 60 percent equity structure, while electricity transmitters, generators, and gas utilities have deemed capital structures that are determined on a case-by-case basis).[137] The OEB went on to note that it will review the cost of capital methodology every five years or earlier if the methods are viewed to be producing results that do not meet the Fair Return Standard.[138]

f. Québec Régie de l'énergie Decision D-2009-156: *Demande de modifier les tarifs de Société en commandite Gaz Métro à compter du 1^{er} octobre 2009*

On 7 December 2009, the Québec Régie de l'énergie (Régie) issued its decision relating to Gaz Métro's cost of capital application.[139] In the decision, the Régie rejected Gaz Métro's request for an ATWACC of 7.75 percent. Instead, the Régie set a capital structure of 38.5 percent common equity, 7.5 percent preferred equity, and 54 percent debt. As well, the Régie modified certain parameters of its formula and reset the ROE at 9.2 percent for fiscal year 2010.[140] This represents a marked increase from the ~8.64 percent that the Régie's prior formula would have produced for 2010.

For 2011, the Régie maintained the status quo with respect to the imposition of an automatic adjustment formula that links the ROE to a forecast of a long-term Government of Canada bond yield and adjusts the ROE for 75 percent of the change in the forecasted yield.

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135 *Ibid.* at Appendix A.
136 *Ibid.* at 51-52.
137 *Ibid.* at 50.
138 *Ibid.* at 64.
139 *Demande de modifier les tarifs de Société en commandite Gaz Métro à compter du 1er octobre 2009*, Québec Régie de l'energie Decision D-2009-156 (7 December 2009).
140 *Ibid.* at 82.

g. British Columbia Utilities Commission Decision to Order No. G-158-09: *In the matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure*

On 17 December 2009, the British Columbia Utilities Commission (BCUC) issued its decision relating to the ROE and capital structure of Terasen Gas Inc. (TGI), Terasen Gas (Vancouver Island) Inc. (TGVI), and Terasen Gas (Whistler) Inc. (TGW).[141]

Similar to the other provincial decisions on this issue, the BCUC's decision provided a significant increase to TGI's ROE in the amount of 9.5 percent, effective 1 July 2009. Under the previous BCUC Formula (also similar to the RH-2-94 Formula), TGI would have received ~8.47 percent. TGVI and TGW both received a ROE of 10 percent. The BCUC's decision also impacted FortisBC Inc.'s (FortisBC) ROE — increasing it to 9.90 percent (which, again, was a significant increase from the ~8.87 percent that it would have received under the prior BCUC Formula).

In terms of capital structure, the BCUC set TGI's common equity at 40 percent (instead of 35.01 percent), effective 1 January 2010.[142] The BCUC maintained the status quo with TGVI, TGW, and FortisBC — maintaining the 40 percent common equity thickness.

The BCUC also determined that U.S. data may be relevant in its determination of a fair return, stating that "natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics."[143] Further, the BCUC was of the view that the automatic adjustment mechanism that was used to determine the ROE on an annual basis should no longer apply, directing TGI to complete a study of alternative formulae and report to the BCUC by 31 December 2010.[144]

h. Concluding Comments

Federal and provincial ROE decisions issued in 2009 marked a significant milestone in the evolution of cost of capital matters in Canada. It is now virtually unanimous that ROE formulae modelled after the NEB's RH-2-94 Formula are no longer appropriate in today's financial environment. That is not to say, however, that similar approaches may not be revisited in the future should capital markets return to "normal" conditions.

6. REGULATION OF GROUP 2 PIPELINE COMPANIES

The NEB regulates pipeline companies as Group 1 or Group 2 companies. Generally, the tolls and tariffs respecting Group 2 pipeline companies are regulated on a complaints basis and reviewed by the Board upon complaint by an interested party.[145]

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141 *In the matter of Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc. and Return on Equity and Capital Structure*, BCUC Decision to Order No. G-158-09 (16 December 2009), online: BCUC <http://www.bcuc.com/Default.aspx>.

142 *Ibid.* at 37.

143 *Ibid.* at 16.

144 *Ibid.* at 72-73.

145 See NEB, *Filing Manual* (Calgary: NEB Publications Office, 2004) at 5P-10, 5P-11, online: NEB <http://www.neb-one.gc.ca/clf-nsi/rpblctn/ctsndrgltn/flngmnl/flngmnl-eng.pdf>.

On 23 December 2009, Many Islands Pipe Lines (Canada) Limited (MIPL) — a Group 2 pipeline company — filed with the Board, pursuant to s. 60(1)(a) of the *NEB Act*,[146] revisions to its tariff, including toll schedules, to be effective 1 January 2010.[147] In its filing, MIPL noted that shipper comments regarding the proposed changes had been "satisfactorily resolved."[148] By letter dated 31 December 2009,[149] absent any filings by shippers, the Board wrote to MIPL indicating that it had not provided justification for the significant increases to tolls. Therefore, until the Board had information upon which to determine that the proposed tolls complied with the just and reasonableness requirements of the *NEB Act*, and were not unduly discriminatory, the tolls would be interim.

While MIPL was of the view that the 23 December filing contained information required by the Board's filing requirements and was consistent in content with prior MIPL filings with the Board, MIPL complied with the Board's request and provided additional pipeline specific information supporting justification for the increased tolls, including the tolling methodology. Following its review of the information, the Board determined that the tolls as filed were just and reasonable and therefore approved the tolls as final.[150]

7. NEB DECISION RH-2-2008: *LAND MATTERS CONSULTATION INITIATIVE STREAM 3: FINANCIAL ISSUES RELATED TO PIPELINE ABANDONMENT*[151]

Announced in the fall of 2007, the NEB's Land Matters Consultation Initiative (LMCI) was initiated by the Board in support of its continued improvement related to land matters.[152] As noted in a speech by Board Member Habib in April 2009, the "LMCI is the largest outreach and consultation effort the Board has ever undertaken with landowners and others potentially impacted by pipelines."[153] From the outset, the Board addressed the LMCI and key land issues in four separate streams: Stream 1 — Company Interactions with Landowners; Stream 2 — Improving the Accessibility of NEB Processes; Stream 3 — Financial Issues Surrounding Pipeline Abandonment; and Stream 4 — Physical Issues Surrounding Pipeline Abandonment.

146 *Supra* note 4.

147 *Many Islands Pipe Lines (Canada) Limited — Section 60 NEB Act Application*, NEB Application TO-03-2010 (23 December 2009).

148 *Ibid.* at 1.

149 Letter from Anne-Marie Erickson, Acting Secretary, NEB to Marilyn P. Wappel, Counsel, MIPL, "MIPL Section 60 Application of the *National Energy Board Act* for Final Tolls and Transportation Tariff to be Effective 1 January 2010" (31 December 2009).

150 Letter from Anne-Marie Erickson, Acting Secretary, NEB to Marilyn P. Wappel, Counsel, MIPL, "Many Islands Pipelines (Canada) Limited (Many Islands) Final Tolls for 2010 — Order TO-03-2010" (13 May 2010).

151 *Land Matters Consultation Initiative Stream 3: Financial Issues related to Pipeline Abandonment*, NEB Decision RH-2-2008 (May 2009) [*RH-2-2008*].

152 See NEB, "Strategic Plan 2009-2012," online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/whwrndrgvrnnc/strtgcpln20092012-eng.html>. As a result of the LMCI, the goals in the Plan were revised to include the expectation that "rights and interests of those affected by NEB-regulated facilities and activities are respected."

153 Georgette Habib, "Land Matters Consultation Initiative" (Presented at the Saskatchewan Oil and Gas Forum, 23-24 April 2009), online: NEB <http://www.neb-one.gc.ca/clf-nsi/rpblctn/spchsndprsnttn/2009/ssktchwnlgsfrm/ssktchwnlgsfrm-eng.html>.

a. Streams 1, 2, and 4

In May 2009, the NEB approved the final report of the LMCI outlining action plans for Streams 1, 2, and 4 to address concerns raised during the consultation process.[154] Recent updates on all processes were issued by the Board in February 2010 indicating the current status of action items for each Stream, as follows:

i. *Stream 1 — Company Interactions with Landowners*

The Board is currently conducting voluntary and non-regulatory assessments of company public involvement programs, developing additional guidance on crossings, developing a standard landowner information package, and has improved its communications of agricultural issues.[155]

ii. *Stream 2 — Improving the Accessibility of NEB Processes*

The Board continues to develop its appropriate dispute resolution programs and participant funding. It is also in the process of developing support for non-industry interveners and is seeking to improve accessibility and sharing of information. It continues to seek clarification of its inspection programs and establishment of a working group with representatives of groups impacted by pipeline development.[156]

iii. *Stream 4 — Physical Issues Surrounding Pipeline Abandonment*

The Board has developed principles for end-state land post-abandonment and clarified its jurisdiction post-abandonment. It is developing compliance verification processes and has formed a Pipeline Abandonment Physical Issues Committee.[157]

b. Stream 3 — Pipeline Abandonment — Financial Issues

The Board held a public hearing in January 2009 to consider Stream 3 issues. The key issue was determining the optimal way to ensure that funds would be available when abandonment costs are incurred, and whether the Board should require pipeline companies to set aside funds to cover future abandonment costs (and if so, how to establish preliminary estimates, timing for collection of funds, and how to govern the funds); how to manage the risks; and the Board's mandate to require collection of abandonment costs as part of the revenue requirement.

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154 NEB, *Land Matters Consultation Initiative: Streams 1, 2 and 4 — Final Report* (Calgary: NEB Publications Office, 2009).

155 NEB, "Stream 1 Actions Progress Report — Company Interactions with Landowners," online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/pblcprtcptn/lndmttrs/strm1/strm1ctnprgrss2010_02-eng.html>.

156 NEB, "Stream 2 Actions Progress Report — Improving the Accessibility of NEB Processes," online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/pblcprtcptn/lndmttrs/strm2/strm2ctnprgrss2010_02-eng.html>.

157 NEB, "Stream 4 Actions Progress Report — Pipeline Abandonment — Physical Issues," online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/pblcprtcptn/lndmttrs/strm4/strm4ctnprgrss2010_02-eng.html>.

Pursuant to s. 15(1) of the *NEB Act*, the Board appointed a three member panel to conduct the *RH-2-2008* proceedings and to make recommendations to the NEB on the issues. In May 2009, the Board adopted the recommendations of the three member panel and pursuant to *RH-2-2008*,[158] all pipeline companies regulated by the NEB are required to submit estimates of funds required for abandonment, as well as proposals for how the companies will collect and set aside those funds. The goal is to have companies setting aside funds no later than the end of May 2014.[159]

In addition to the substantive determination regarding abandonment costs, the Board confirmed its authority to require companies to set aside funds for abandonment, relying in part on its authority under the *NEB Act* to determine just and reasonable tolls. In its view, "the authority set out in Part IV of the NEB Act is sufficiently broad to allow the Board to embark on the inquiry, and issue a decision on whether the Board should require the collection of abandonment costs as a component of a company's revenue requirement."[160] The two key fundamental principals arising from *RH-2-2008* were that abandonment costs were "legitimate costs of providing service," and were "recoverable upon Board approval from users of the system," and that the costs of not only construction and operation, but also abandonment, would be the responsibility of pipeline companies.[161]

Base case assumptions were identified in *RH-2-2008* for the purposes of developing and filing preliminary estimates of future abandonment costs related to factors such as inflation rate, method of abandonment, estimated salvage value, abandonment cost information, economic life, and return on funds collected.[162] These were later revised. Companies are permitted to develop their own base case assumptions to develop abandonment cost estimates.

In March 2010 correspondence, the Board also addressed the frequency and scope for the review of the assumptions, stating that it intended to revisit the base case assumptions "at least every five years."[163] The Board also provided guidance for the filing of abandonment cost information and expects that companies will make use of the filing guidance provided or justify why they are unable to do so.[164] The Board invited parties to contact the Board to provide additional suggestions on filing guidance.

8. NEB HEARING ORDER GH-1-2004:[165] *REGARDING APPLICATIONS TO THE NATIONAL ENERGY BOARD FOR THE MACKENZIE GAS PROJECT*

In 2004, the proponents of the Mackenzie Gas Project filed regulatory applications for approval to construct and operate the Mackenzie Gas Project. The seven member joint review

158 *Supra* note 151.
159 *Ibid.* at 4.
160 *Ibid.* at 31.
161 *Ibid.* at 36-37.
162 *Ibid.*, c. 4.
163 Letter from Anne-Marie Erickson, Acting Secretary, NEB to various parties, "RH-2-2008 Reasons for Decision: LMCI Stream 3, Pipeline Abandonment — Financial Issues Technical Conference — Revisions to Preliminary Base Case Assumptions" (4 March 2010) at 18.
164 *Ibid.* at Appendix A.
165 *Regarding Applications to the National Energy Board for the Mackenzie Gas Project*, NEB Hearing Order GH-1-2004 (24 November 2004).

panel (JRP) appointed in 2004 by the Canadian federal government reviewed the environmental, socio-economic, and cultural effects of the pipeline. JRP proceedings commenced February 2006 and were concluded approximately 22 months later in November 2007. The NEB held the evidentiary portion of the proceeding in 2006. Final argument before the NEB was heard in April 2010.[166]

While the JRP has been criticized for both the time and cost of completing its review,[167] a significant milestone was reached on 30 December 2009 with the issuance of the 679-page JRP Report.[168] The JRP Report concluded that the project "would provide the foundation for a sustainable northern future" and "would likely make a positive contribution towards a sustainable northern future."[169] These conclusions were, however, premised on the full implementation of the 176 recommendations contained in the JRP Report relating to a broad range of matters including the adoption of initiatives by all levels of government; protection of polar bears, permafrost, workers, and First Nations; and no future expansions until certain land use plans of First Nations are complete.

In response to the Board's request for comments on the JRP's recommendations, proponents generally submitted that the NEB should reject recommendations that relate to future applications and those requiring agreement of third parties and expressed their opposition to a number of the proposed recommendations, particularly those based on the JRP's cumulative impact assessment.[170]

On 9 March 2010, the NEB issued two letters. One letter was issued to all parties to the Mackenzie Gas Project proceeding providing the NEB's proposed conditions for the project and invited parties to comment on these conditions during final argument.[171]

The other letter was issued to the JRP as part of the NEB's "consult to modify" process regarding the JRP recommendations, a process unique to the Mackenzie Gas Project hearing

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166 The NEB conducted a process for receiving comments on recommendations from the proponent and parties during the period 28 January to 31 March 2010. On 21 January 2010, the Board denied a motion by the Dehcho First Nation requesting an adjournment to final argument until the federal government and government of the Northwest Territories provided to parties their position on the JRP Report: letter from Anne-Marie Erickson, Acting Secretary, NEB to interested parties, "Mackenzie Gas Project (MGP) — Hearing Order GH-1-2004: Dehcho First Nations — Notice of Motion, NEB Ruling No. 25" (21 January 2010).

167 Joint Review Panel for the Mackenzie Gas Project, *Foundation for a Sustainable Northern Future: Report of the Joint Review Panel for the Mackenzie Gas Project* (Ottawa: Minister of Environment, 2009) [JRP Report].

168 The budget in 2004 for the JRP Report was expected to be $6.8 million. However, in March 2009, estimates were closer to $18 million. An article in the *Calgary Herald* noted that the JRP Report "was three years late and $10 million over budget": Dina O'Meara, "Panel approves Mackenzie pipeline project" *Calgary Herald* (31 December 2009), online: Calgary Herald <http://www.calgaryherald.com/technology/Panel+approves+Mackenzie+pipeline+project/2392875/story.html>.

169 JRP Report, *supra* note 167 at 13. Also on 30 December 2009, Panel Member Rowland Harrison, who was appointed pursuant to s. 15(1) of the *NEB Act*, issued his report agreeing with the JRP Report conclusions and recommending that the NEB consider the JRP Report recommendations to the extent that the recommendations are within the jurisdiction of the NEB: letter from Rowland J. Harrison to Anne-Marie Erickson, Acting Secretary, NEB, "Mackenzie Gas Project — Hearing Order GH-1-2004 — NEB Authorization Order MO-13-2004" (30 December 2009).

170 See e.g. Letter from Rick D. Pawluk, Manager, Regulatory Affairs, Imperial Oil Resources Ventures Limited to Anne-Marie Erickson, Acting Secretary, NEB, "Mackenzie Gas Project — Hearing Order GH-1-2004: Proponents' Comments on JRP Recommendations Within the NEB's Mandate" (28 January 2010).

171 Letter from Anne-Marie Erickson, Acting Secretary, NEB to various parties, "Mackenzie Gas Project — Hearing Order GH-1-2004: Proposed Conditions" (9 March 2010).

process.[172] The stated purpose of the letter was to "consult with the JRP on possible modifications to the specific recommendations in the Report that were directed to the NEB" and further identified how the NEB was proposing to address some of the JRP recommendations.[173] In essence, the NEB comments that some recommendations were not within its jurisdiction and that "the NEB is considering not including such recommendations as conditions."[174] Further, the NEB advised that it was considering requiring that the proponents consult with the appropriate parties and file those results with the NEB, rather than having other parties approve filings made by the proponents to the NEB.[175] The Board also suggested that it would not include conditions in its decision that related to future applications.[176]

The JRP responded to this letter on 29 March stating that "subject to the following two paragraphs, the NEB Proposed Conditions have not rejected any of the Panel's recommendations that are directed to the NEB."[177] The referenced "following two paragraphs" state:

> [T]he NEB has noted in several instances that the relevant JRP recommendation is "[o]utside the scope of the Mackenzie Gas Project (MGP) applications as it involves future application(s)." The JRP does not understand this notation to be a rejection by the NEB of the relevant recommendation. The relevant JRP recommendations stand and the Panel expects that they would, accordingly, be considered by the NEB in the specific context of any future applications.
>
> In several other instances, the NEB has noted … that certain JRP recommendations are "within the jurisdiction of other regulatory authorities…" In these instances, the substance of the Panel's recommendations stands and the specific recommendations should be read as being directed to the relevant regulatory authority.[178]

The closing paragraph of the JRP letter affirmed its overall conclusions regarding potential impacts, noting that such conclusions were "*subject to the full implementation of the Panel's recommendations*."[179]

The NEB advises that it anticipates releasing its reasons for decision in September 2010,[180] which will address issues that were not considered by the JRP, such as engineering, safety, and economic matters and will, in remedial measures within the mandate of the NEB, also

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172 Letter from Anne-Marie Erickson, Acting Secretary, NEB to Robert Hornal, Chair, Joint Review Panel for the Mackenzie Gas Project, "Mackenzie Gas Project (MGP) — Hearing Order GH-1-2004: Consult to Modify Process for the Recommendations Identified in the Joint Review Panel (JRP) Report on the Environmental Impact Review of the Mackenzie Gas Project" (9 March 2010).

173 *Ibid.* at 1.

174 *Ibid.* at 3.

175 *Ibid.*

176 *Ibid.* at 4.

177 Letter from Robert Hornal, Chair, Joint Review Panel for the Mackenzie Gas Project to Anne-Marie Erickson, Secretary, NEB, "Mackenzie Gas Project (MGP) — Hearing Order GH-1-2004: Consult to Modify Process for the Recommendations Identified in the Joint Review Panel (JRP) Report on the Environmental Impact Review of the Mackenzie Gas Project" (29 March 2010) at 2.

178 *Ibid.*

179 *Ibid.* [emphasis in original].

180 NEB, News Release, 10/09, "National Energy Board to Hear Final Argument on Mackenzie Gas Project" (8 April 2010), online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/nwsrls/2010/nwsrls09-eng.html>.

consider the recommendations of the JRP. If approved by the NEB and other examinations are completed,[181] the project sponsors will need to determine whether to proceed with the proposed 1,200 km pipeline. If constructed, the pipeline would be the first to bring Canadian Arctic gas reserves to market, and would be the largest pipeline construction in Canadian history.[182]

9. ENBRIDGE INC. — NORTHERN GATEWAY PROJECT

On 1 November 2005, Gateway Pipeline Inc. (Gateway) filed with the NEB and the Canadian Environmental Assessment Agency (CEA Agency) a preliminary information package (PIP) in respect of the proposed Northern Gateway Pipeline, which would be a dual pipeline system — an export oil pipeline and an import condensate pipeline — each approximately 1,170 km in length between Bruderheim, Alberta, and Kitimat, British Columbia. Crude would be carried west to Kitimat and condensate would be carried east to Bruderheim. The proposed project would also include the construction and operation of integrated marine infrastructure to accommodate loading and unloading of oil and condensate tankers and marine transportation of oil and condensate.

On 4 December 2009, a JRP agreement, signed by the federal Minister of the Environment and the Chair of the NEB, was issued in respect of the environmental and regulatory review. The agreement includes the terms of reference for the project as well as the process for appointing the Panel members and the role of the Panel in Crown consultation.[183] As noted in the Board's *Backgrounder* regarding the JRP agreement, "[t]he Agreement defines the boundaries for the assessment of potential environmental effects associated with marine transportation for this project."[184] The NEB notes in this publication that during the public comment period for the agreement, many comments were submitted on the issue of marine traffic. In this regard, the Board states that "[i]t is the Government of Canada's position that there is presently no moratorium on tanker traffic in the coast waters of B.C. Tanker traffic currently exists in the Ports of Vancouver, Kitimat and Prince Rupert."[185]

On 20 January 2010, Jim Prentice (Canada's Minister of the Environment) and Gaétan Caron (Chair and Chief Executive Officer of the NEB) announced that a three member JRP had been established for the environmental and regulatory review of the project in order to determine whether the project is likely to cause significant adverse environmental effects and if it is in the public interest.[186] In March 2010, more than $400,000 was awarded as participant funding in respect of the *CEAA* process. The project, which proposes more than

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181 For example, the project will be examined by agencies that oversee Aboriginal land claims and territorial waters.

182 Nathan VanderKlippe, "Swords already drawn over Mackenzie report," *The Globe and Mail* (1 January 2010) B1.

183 NEB & CEA Agency, *Agreement Between the National Energy Board and the Minister of the Environment Concerning the Joint Review of the Northern Gateway Pipeline Project* (4 December 2009), online: CEA Agency <http://www.ceaa-acee.gc.ca/050/documents/40851/40851E.pdf>.

184 NEB, "Northern Gateway Pipeline Project Joint Review Panel Agreement and Terms of Reference" *Backgrounder* (4 December 2009) at 2, online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/nwsrls/2009/nrthrngtwjrp grmntbckgrndr-eng.pdf>.

185 *Ibid.* at 1.

186 NEB, News Release, "Joint Review Panel Established for the Northern Gateway Pipeline Project" (20 January 2010), online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/nwsrls/2010/nrthrngtwjrp stblshmnt-eng.pdf>.

1,000 stream and river crossings and proposes to cross more than 50 First Nations territories (half of which have voiced opposition to the project), has been mired in controversy even prior to the filing of a formal application with the NEB on 27 May 2010, officially commencing the regulatory review.

10. NEB DECISION MH-3-2008: *ENBRIDGE PIPELINES INC.: DETAILED ROUTE HEARING — ALBERTA CLIPPER EXPANSION PROJECT*[187]

The general practice of the NEB pursuant to the *NEB Act* is to determine, pursuant to the Board's detailed route procedure in accordance with ss. 33-39 of the *NEB Act*, a detailed location for a pipeline following the issuance of a Certificate of Public Convenience and Necessity (CPCN). Detailed route hearings consider the best possible detailed route for a project and the most appropriate methods and timing of construction having regard to both objections and evidence filed in the proceeding. During the detailed route hearing, issues already addressed during the certificate proceedings are not considered.

Following the filing of an applicant's PPBoR, the Board considers the location of the pipeline as well as the type and amount of land rights required. Landowners have an opportunity to intervene to present their own evidence of the appropriate detailed route for a pipeline and the most appropriate methods and timing of construction.

On 8 May 2008, the CPCN for the Enbridge's Alberta Clipper Expansion Project was approved by the Governor in Council. With respect to detailed routing, 28 letters of opposition were received. Of these, 16 were withdrawn and the Board found that five did not meet the statutory requirements set out in ss. 34(3) and (4) of the *NEB Act*. Seven were set down for hearing.[188]

The main concern raised by the landowners was the potential for land use conflicts given the close proximity of the proposed route to the City of Regina and its impacts on the ability to develop the land.[189] Although three alternate routes were proposed by the landowners for consideration, the Board approved the detailed route proposed by Enbridge. The Board recognized that the proximity of a pipeline to urban areas "is a relevant consideration" for determining the best possible route but was satisfied that the distance was sufficient in the circumstances to avoid land use conflicts.[190] Further, the Board found the landowners' development plans to be speculative and, moreover, found that the pipeline could be accommodated if development proceeded. Noting the commitments of Enbridge to mitigate potential impacts and explore the possibility of reducing the right-of-way width, the Board approved the detailed route of the pipeline proposed by Enbridge.

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187 *Enbridge Pipelines Inc.: Detailed Route Hearing — Alberta Clipper Expansion Project,* NEB Decision MH-3-2008 (May 2009).

188 *Ibid.* at 4.

189 *Ibid.* at 15.

190 *Ibid.* at 19.

11. NEB DECISION MH-1-2009: *KINDER MORGAN CANADA COMPANY: WINDSOR-SARNIA PIPELINE SECTION 21 REVIEW AND SECTION 71 APPLICATIONS — REQUEST FOR SERVICE*[191]

The Windsor-Sarnia Pipeline (WSP), owned by Dome NGL Pipeline Ltd. (Dome), is an approximately 130 km 12-inch pipeline originally designed to be capable of transporting ethylene, ethane, propane, butane, and mixed NGL. Its inlet is connected to the Cochin Pipeline and is not configured to receive deliveries from any other pipeline or facility. By Board Order MO-04-2009, the Board authorized the deactivation of the line.[192]

By application dated 31 March 2009, Kinder Morgan Canada Company (Kinder Morgan) applied for relief pursuant to ss. 21(1), 71(1) and (3), and 59 of the *NEB Act* in respect of the WSP, in particular requesting that the NEB review Order MO-04-2009 and, further, that the Board compel Dome to provide service and adequate facilities for transport of NGL, as well as a tariff for service.

While the Board issued a letter dated 30 June 2009 dismissing comments by Kinder Morgan and NOVA Chemicals Corporation (NOVA) that suggested that Dome failed to notify the parties of the deactivation application that led to Order MO-04-2009, the Board found that "the deactivation application did not adequately disclose the unresolved concerns of potential shippers with respect to service on the [WSP]."[193] The Board found that this raised a doubt as to the correctness of the Board's decision to issue Order MO-04-2009, and the Board proceeded to a review on its merits. The Board scheduled a public hearing commencing 19 January 2010. The hearing took place over a five-day period, with argument closing on 26 January 2010.

In its conclusion, the Board "directed Dome to provide service under subsection 71(1), to effect the reconnection of facilities under subsection 71(3) and to file a tariff under Part IV and section 59 of the Act."[194] Further, the Board rescinded Order MO-04-2009, which initially authorized the deactivation of the WSP. While the Board granted the review and the relief requested in the application, the Board found that Kinder Morgan was not a shipper offering NGL for transmission. Rather, the Board based its decision to rescind Order MO-04-2009 and to require Dome to provide service on the evidence of NOVA and, in particular, NOVA's "serious request for service on the WSP."[195]

Dome was of the view that if the WSP was returned to service, capacity would be "available to all shippers on a common carrier basis" and would not be restricted to Cochin Pipeline shippers.[196] While the Board considered existing commercial arrangements with shippers on the WSP, the Board was of the view that commercial arrangements do not

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191 *Kinder Morgan Canada Company: Windsor-Sarnia Pipeline Section 21 Review and Section 71 Applications — Request for Service*, NEB Decision MH-1-2009 [*Kinder Morgan*].

192 Letter and Order MO-04-2009 from Claudine Dutil-Berry, Secretary, NEB to Suzanne Boucher-Chen, Director, Regulatory Affairs NGL, BP, "Dome NGL Pipeline Ltd. (Dome NGL) — 2008 Application Pursuant to Section 44(1) of the *Onshore Pipeline Regulations, 1999* for Leave to Deactivate the Windsor-Dow Pipeline" (10 February 2009) [Order MO-04-2009].

193 *Kinder Morgan*, *supra* note 191 at 36.

194 *Ibid.* at 27.

195 *Ibid.* at 24.

196 *Ibid.* at 9.

constrain the Board's deliberations.[197] Despite the configuration of facilities, which allowed that only the Cochin Pipeline could deliver product to the WSP, the Board found that WSP was a common carrier and that its obligation as a common carrier pursuant to s. 71(1) of the *NEB Act* applied to all oil products that the WSP CPCN authorized it to transmit.[198] The statutory common carrier obligations were not impacted by contractual terms.

Kinder Morgan confirms, in several respects, the Board's historical view of the common carrier obligations pursuant to s. 71(1) of the *NEB Act*, including, generally, that s. 71(1) reflects the common law duties of a common carrier pipeline. Recognizing that the Board has previously held that the common carrier obligations are subject to a test of reasonableness, Dome's position in the hearing was that it would, if directed by the Board, provide service on the WSP provided that capacity would be available to all shippers; there was a reasonable assurance of cost recovery; and that appropriate facilities were constructed.[199] The Board acknowledged the reasonableness requirement in its decision, and in this regard, its direction for Dome to offer service was contingent on Dome having "a reasonable opportunity to recover its costs" from shippers.[200] This reasonable opportunity appears to have been met through commitments by NOVA to enter a facilities support agreement or to cover costs of service in the event it was the only shipper.[201]

In its discussion of the requirements under s. 71(3), the Board recognized the express wording of s. 71(3) of the *NEB Act*, which allowed the Board to make an order requiring Dome to provide adequate and suitable facilities if "no undue burden"[202] would be placed on Dome.[203] Although the potential need to construct a meter station and other facilities was left to the negotiation of the parties, the Board required Dome to reconnect certain facilities (the spool piece and pump) in relation to the WSP, finding that the provision of these facilities would not place an undue burden on Dome. However, this conclusion was specifically premised on NOVA having committed to a facilities support agreement. In this regard, the Board recognized NOVA's willingness to commit to a facilities support agreement and to cover the entire cost of service in the event that no other shippers utilized the reactivated pipeline.

In the course of the hearing, the Board was also required to consider whether there were transportation alternatives to the WSP. It heard evidence from the parties regarding the feasibility of alternatives. The main alternative put forth was the potential for service on the Eastern Delivery System (EDS), which was a pipeline system owned by Dome running generally parallel to the WSP. The Board considered whether the EDS provided a "physically feasible and comparable service that can reasonably satisfy the transportation needs of the parties requesting the service, in a timely manner."[204] The evidence of NOVA, which was accepted by the Board, was that service on the WSP and EDS was "not comparable," particularly given the cost of using terminalling and storage services in relation to the EDS

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197 *Ibid.* at 26.
198 *Ibid.* at 22.
199 *Ibid.* at 9.
200 *Ibid.* at 26.
201 *Ibid.* at 24.
202 *NEB Act*, *supra* note 4.
203 *Kinder Morgan*, *supra* note 191 at 25.
204 *Ibid.* at 23.

and having regard to the uncertainty of storage service availability in relation to the EDS.[205] Differences in tolls were not considered by the Board to be relevant in the circumstances.

12. NEB HEARING ORDER RH-2-2010: APPLICATION FOR TOLL AND TARIFF RELIEF ON ENBRIDGE PIPELINES INC. ALBERTA CLIPPER EXPANSION PROJECT[206]

On 22 February 2010, Suncor and Imperial Oil filed an application with the NEB requesting, *inter alia*, a determination from the NEB disallowing all costs incurred for the construction of the Alberta Clipper facilities from Enbridge Mainline System (Enbridge Mainline) tolls. In the alternative, the applicants requested that the NEB issue an order limiting toll impacts on the Enbridge Mainline to the toll level relied upon in evidence at the OH-4-2007 proceeding. While the NEB has not yet made a final ruling regarding the application, by letter dated 31 March 2010, the NEB required Enbridge to refile interim tolls for the Enbridge Mainline "that would use the same unit toll increases as estimated during the OH-4-2007 proceeding … for the Clipper Project."[207] The revised interim tolls were approved by the NEB on 1 April 2010.[208] Suncor and Imperial also requested, on both an interim and a final basis, to be relieved of certain linefill obligations in the Enbridge Mainline tariff. The Board denied the request to suspend the tariff on an interim basis without prejudice to resolution of the issue at a hearing to commence 9 November 2010 to address, on a consolidated basis, the application and the portions of the Enbridge 2010 application for final Enbridge Mainline tolls and tariffs that were contested by interested parties.

13. NOVA GAS TRANSMISSION LTD. — APPLICATION FOR APPROVAL OF A RATE DESIGN METHODOLOGY AND TERMS AND CONDITIONS OF SERVICE AND THE INTEGRATION OF THE ATCO PIPELINES SYSTEM WITH NGTL'S ALBERTA SYSTEM

In Alberta, gas transmission service is primarily provided by two utilities, namely ATCO Pipelines (AP) and NGTL. Historically, the competition between these companies has often resulted in contentious regulatory proceedings and resulting costs for both the companies and their customers. Encouraged by both their regulator and customers to seek collaborative approaches to streamlining the provision of natural gas transmission service in Alberta, an application was filed by AP with the AUC on 26 June 2009 requesting approval for integrating the AP system with that of NGTL. The proposed transaction, which is reflected in an agreement between the parties dated 7 April 2009, was described in a TransCanada Pipeline 8 September 2008 news release as follows:

> If approved by the regulator, the arrangement will see the two companies combine physical assets under a single rates and services structure with a single commercial interface with customers but with each company

205 *Ibid.*

206 *Suncor Energy Marketing Inc. and Imperial Oil Application, and Enbridge Application dated 31 March 2010 for Final Tolls effective 1 May 2010*, NEB Hearing Order RH-2-2010 (13 May 2010).

207 Letter from Anne-Marie Erickson, Secretary, NEB to Ralph Fisher, Director, Planning and Analysis, Enbridge, "Enbridge Pipelines Inc. (Enbridge) NEB Tariff No. 303, 2010 Canadian Mainline Interim Tolls Application (Application)" (31 March 2010) at 4.

208 While a petition was filed with the U.S. Federal Energy Regulatory Commission on 13 January 2010 requesting declaratory toll relief, that petition was denied on 31 March 2010.

separately managing assets within distinct operating territories in the province. It is expected that the model will end duplicative tolling and operational activities and will result in more efficient regulatory processes.[209]

The integration proposal would intend to benefit transmission customers by providing streamlined gas transmission services across Alberta, whereby parties would interface solely with NGTL, enter a single contract for service, and be subject to one set of terms and conditions while being subject to fewer (streamlined) regulatory processes and proceedings.

The AUC application for integration requested approval pursuant to s. 22 of the *Gas Utilities Act*[210] and a declaration that the integration was in the public interest and convenience; s. 36 of the *GUA* for determination of AP's 2010-2012 revenue requirement; ss. 22 and 36 of the *GUA* to transition AP's contracts to NGTL Alberta System contracts; and s. 26 of the *GUA* for the sale of AP assets to NGTL to effect the "swap" of assets between the two transmission companies. The AUC considered the application through a written process and rendered its decision approving integration on 27 May 2010.[211]

NGTL filed a corresponding application with the NEB on 27 November 2009 requesting the approval of a rate design methodology, terms and conditions of service, tariff amendments, and a toll transition mechanism for customers (as per the terms of a settlement) and for the integration of the AP system with the system of NGTL (which would include in NGTL's annual revenue requirement the AP revenue requirement as approved by the AUC), describing as well the transitioning of AP's existing service contracts to NGTL Alberta system service agreements and the need for a swap of assets. Most parties expressed support for the toll methodology and the integration. In its 12 August 2010 decision, the NEB approved the rate design methodology settlement. In order to assess the continued appropriateness of the rate design methodology, the Board also directed NGTL to file rate design studies with the Board by 1 July 2012 (using forecast flow scenarios for 2010) and again by 1 July 2015 (using actual 2014 flows). The Board also approved the integration agreement between NGTL and AP "insofar as its commercial implications are incorporated in NGTL's rate design methodology and services."[212] Finally, in relation to NGTL's request for approval in principle of the asset swap, the Board indicated that it was premature to make any findings in this issue. In the Board's view the asset swap would require a separate application pursuant to s. 74 of the *NEB Act*.

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209 TransCanada, News Release, "TransCanada (NGTL) and Canadian Utilities Limited (ATCO Pipelines) Reach Proposed Agreement to Provide Seamless Alberta Natural Gas Transmission Service" (8 September 2008), online: TransCanada <http://www.transcanada.com/3073.html>.

210 R.S.A. 2000, c. G-5 [*GUA*].

211 *ATCO Pipelines: 2010-2012 Revenue Requirement Settlement and Alberta System Integration*, AUC Decision 2010-228 (27 May 2010).

212 *Nova Gas Transmission Ltd. (NGTL): Rate Design Methodology and Integration Application*, NEB Decision RHW-1-2010 (12 August 2010) at 12.

B. FEDERAL COURT

1. *STANDING BUFFALO DAKOTA FIRST NATION V. ENBRIDGE PIPELINES*[213]

The Keystone XL Project, Southern Lights Project, and the Alberta Clipper Expansion Project were each considered by the NEB pursuant to separate proceedings and oral hearings and subsequently approved by separate decisions of the NEB. The Standing Buffalo Dakota First Nation was an intervener in all three proceedings. The SFN and MFN participated in the Alberta Clipper proceedings.

These three First Nations filed four separate appeals with the Federal Court of Appeal in respect of the NEB decisions and approvals issued for these pipelines, requesting that the approvals be set aside. The First Nations argued that the NEB was required, and failed, to consider whether the Crown had a duty to consult the First Nations in respect of the proposed projects before making a decision on the merits in respect of the pipeline projects. The Court dismissed each of the appeals on 23 October 2009, with costs to the respective Enbridge entities and TransCanada.

In dismissing the appeals, the Court noted that the issue raised by the First Nations on appeal was squarely before the Board in both the Southern Lights and Alberta Clipper proceedings. While the issue was not raised directly in the Keystone proceeding, it formed the basis of a review application following the Board's decision regarding that project. In each of the three cases, the NEB denied the request.

In its decision, the Court undertook an analysis of the existence of the Crown's duty to consult as described in *Haida Nation v. British Columbia (Minister of Forests).*[214] While Counsel for the SFN and MFN argued that prior judicial determinations in *Paul v. British Columbia (Forest Appeals Commission*)[215] and *Kwikwetlem First Nation v. British Columbia (Utilities Commission)*[216] were determinative on the issue of whether the NEB was required to undertake a *Haida* analysis before proceeding to a consideration of the project on its merits, the Court disagreed.

The Court interpreted *Paul* as determining a tribunal's jurisdiction to hear questions of Aboriginal rights and an indication "that the courts are the appropriate venue for adjudication of Aboriginal issues."[217] The Court distinguished *Kwikwetlem* (and *Carrier Sekani Tribal Council v. British Columbia (Utilities Commission)*)[218] on the basis that the entity there was accepted by the parties to the proceeding as being the Crown or a Crown agent for purposes of the *Haida* review.[219] Further, the Court noted that in *Kwikwetlem*, the existence of the *Haida* duty was not in issue. Rather, the relevant issue "was whether the Commission could

213 2009 FCA 308, 313 D.L.R. (4th) 217 [*Standing Buffalo*].
214 2004 SCC 73, [2004] 3 S.C.R. 511 [*Haida*].
215 2003 SCC 55, [2003] 2 S.C.R. 585 [*Paul*].
216 2009 BCCA 68, 308 D.L.R. (4th) 285 [*Kwikwetlem*].
217 *Standing Buffalo*, *supra* note 213 at para. 30.
218 2009 BCCA 67, [2009] 4 W.W.R. 381 [*Carrier Sekani*].
219 *Standing Buffalo*, *supra* note 213 at paras. 31-33.

issue an approval without first having decided whether the duty to consult had been discharged."[220]

The Court confirmed that the NEB is not under a *Haida* duty and therefore does not itself owe a duty of consultation to First Nation communities.[221] The Court acknowledged that the NEB did not make any findings as to the existence of a *Haida* duty in its approval of the pipeline projects or whether the Crown was subject to a *Haida* duty in respect of applications brought before it by Enbridge and TransCanada.[222] Further, the Court found that the NEB was under no obligation to do so. Because Enbridge and TransCanada were private sector entities, and not the Crown or Crown agents as in *Kwikwetlem* or *Carrier Sekani,* NEB determinations on the applications did not need to consider the existence of a *Haida* duty.[223] The Court found that the NEB did not err in failing to undertake the *Haida* analysis.

With respect to the NEB process, the Court made several observations. First, it noted that even if the NEB is not required to determine whether the Crown was under, and had discharged, a *Haida* duty, a court can still adjudicate those matters. Further, the Court noted that the availability of judicial recourse was not meant to suggest that First Nations should decline to participate in the NEB process. Indeed, proponents are required to consult with First Nations under the NEB consultation requirements, and the process ensures that the applicant has due regard for Aboriginal rights. In the view of the Court, the NEB "process provides a practical and efficient framework within which the Aboriginal group can request assurances with respect to the impact of the particular project."[224] With respect to First Nation participation, the Court stated:

> While the Aboriginal group is free to determine the course of action it wishes to pursue, it would be unfortunate if the opportunity afforded by the NEB process to have Aboriginal concerns dealt with in a direct and non-abstract matter was not exploited.[225]

On 21 December 2009, the Standing Buffalo Dakota First Nation filed an application for leave to appeal the decision to the Supreme Court of Canada. No decision has been rendered at the time this article is being written. The SFN and MFN also filed a leave to appeal application on 14 December 2009. Again, no decision has been rendered. Should leave be granted, the appellants have requested that the appeal be heard concurrently with the *Carrier Sekani* appeal. However, on 5 November 2009, the Supreme Court granted leave to appeal the *Carrier Sekani* decision on the issue of whether "the honour of the Crown require[s] administrative tribunals to decide disputes about the Crown's duty to consult First Nations, regardless of the tribunal's statutory mandate."[226] The appeal was heard on 21 May 2010. Recent information from the Court suggests that the leave applications respecting *Standing Buffalo* will not be decided until after the *Carrier Sekani* decision is issued.

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220 *Ibid.* at para. 31.
221 *Ibid.* at para. 34.
222 *Ibid.* at para. 25.
223 *Ibid.* at para. 32.
224 *Ibid.* at para. 44.
225 *Ibid.*
226 Bennett Jones LLP, "Are Administrative Tribunals Required to Rule on the Crown's Aboriginal Consultation Duties?" *Energy Update* (January 2010) 5, online: Bennett Jones LLP <http://www.bennettjones.com/Images/Guides/update7969.pdf>.

2. *BROKENHEAD OJIBWAY NATION V. CANADA (A.G.)*

Three applications for judicial review were brought before the Federal Court respecting decisions of the Governor in Council (GIC) to approve the issuance of the CPCN for the construction of the Keystone XL Pipeline Project, the Southern Lights Pipeline Project, and the Alberta Clipper Pipeline Expansion Project (collectively, the projects). The Treaty One First Nations asserted that the Federal Crown failed to fulfill its legal obligation of consultation and accommodation before granting approvals for construction of the projects in their traditional territory. The Court dismissed the judicial review applications, concluding that the Crown's duty of consultation had been met through notices in the context of the NEB proceedings and through the opportunities for consultation and accommodation in the NEB processes.

The Court acknowledged that if there was a duty of the Crown to consult, it must be fulfilled before the GIC provides its final approval for issuance of the CPCN. However, given the impacts of the project on the interests and claims of the First Nations, the Court held that "if the Crown had any duty to consult," it was "at the extreme low end of the spectrum involving a peripheral claim attracting no more than an obligation to give notice."[227] In particular, the Court noted that the projects would be built on lands that were not legally or practically available for future settlement. As the projects would be built over existing rights-of-way and on privately owned land, and would largely be below ground, there was no evidence to demonstrate that the projects were likely to interfere with traditional Aboriginal land use.[228]

Further, the Court found that there was no demonstrated interference with an interest that could not be resolved within the regulatory process. The Court stated that "[e]xcept to the extent that Aboriginal concerns cannot be dealt with, the appropriate place to deal with project-related matters is before the NEB and not in a collateral discussion with either the GIC or some arguably relevant Ministry."[229] Therefore, existing processes for regulatory and environmental review can be considered by the Crown in determining whether, and to what extent, the Crown has a duty to consult, provided that the processes "are accessible, adequate and provide the First Nations with an opportunity to participate."[230] A First Nation cannot, however, complain about a failure by the Crown to consult where the First Nation has failed to avail themselves of the available processes.

The Court was careful to confirm that the availability of regulatory and environmental processes will not necessarily be sufficient in all cases, and is not a delegation of a duty to consult. Rather, those processes are a means by which the Crown can satisfy itself that Aboriginal issues have been considered and, where appropriate, mitigated.[231]

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227 *Brokenhead Ojibway*, *supra* note 35 at paras. 21, 43.
228 *Ibid.* at para. 45.
229 *Ibid.* at para. 37.
230 *Ibid.* at para. 42.
231 *Ibid.* at para. 29.

3. *ALLIANCE PIPELINE LTD. V. SMITH*[232]

In 1999, Alliance Pipeline Ltd. (Alliance) constructed the Alliance Pipeline across the lands of the appellant landowner Smith. A dispute arose regarding the reclamation of some of the land. The landowner was of the view "that it was necessary to apply manure to the entire right-of-way in order to return the land to its pre-construction growing ability."[233] Alliance disagreed. The landowner undertook reclamation work and then requested compensation from Alliance.

Compensation matters related to pipeline construction are addressed through arbitration proceedings under Part V of the *NEB Act*. Upon the filing of a notice of arbitration by the landowner, the Minister of Natural Resources established a panel to consider the landowner's claim. Alliance also filed a statement of claim in the Alberta Court of Queen's Bench seeking an injunction against the landowner to prevent the landowner from interfering with Alliance's rights to unhindered access onto the easement and a declaration that releases that had been entered into by the parties included any and all claims of the landowner. The Court dismissed the injunction application, awarding costs to the landowner on a party and party basis. Such costs, however, did not cover the landowner's solicitor-client costs for the judicial proceedings.

After an Arbitration Committee was appointed pursuant to Part V of the *NEB Act*, one member of the Committee was appointed to the bench. The Minister was then required to appoint a second Arbitration Committee. The main issues to be considered by the Committee related to the landowner's ability to recover from Alliance legal costs incurred in the Queen's Bench proceedings and costs related to the first arbitration.

The Arbitration Committee ruled in favour of the landowner. Having found that it had the jurisdiction to determine all compensation matters identified in the Minister's notice of arbitration, the Committee held that if a party such as Alliance was of the view that the Minister had referred a notice that included matters outside of the Committee's jurisdiction, "the objecting party was bound to seek judicial review of the Minister's decision."[234] Therefore, the Committee awarded the landowner his net legal fees, disbursements, and GST as compensation for damages suffered as a result of the operations of Alliance. The landowner was also awarded legal fees and disbursements incurred in the first arbitration proceedings.

Alliance appealed to the Trial Division of the Federal Court pursuant to s. 101 of the *NEB Act*, arguing that the Committee exceeded its jurisdiction and erred in awarding the landowner litigation costs and costs in the first arbitration. That appeal was dismissed.[235] Alliance then appealed to the Federal Court of Appeal, which allowed the appeal. At issue were ss. 99 and 84 of the *NEB Act*.

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232 2009 FCA 110, 389 N.R. 363 [*Alliance*].
233 *Ibid.* at para. 4.
234 *Ibid.* at para. 16.
235 See *Alliance Pipeline Ltd. v. Smith*, 2008 FC 12, 318 F.T.R. 100.

With respect to s. 99, the issue was whether the costs claimed by the landowner were incurred by the landowner "in asserting that person's claim for compensation."[236] While the Federal Court of Appeal found no error in the lower court's determination that the Committee had jurisdiction to determine whether the landowner was entitled to the costs claimed, the Court held that none of the costs claimed came within the ambit of s. 99(1) of the *NEB Act*.[237] The litigation costs were not "damages" as contemplated in s. 84 of the *NEB Act*. In this regard, the Court was of the view that damages that are caused by the activities of the company are only compensable if they are directly related to those matters enumerated in s. 84.[238] The Court also held that the Arbitration Committee erred in awarding the costs of the first arbitration to the landowner.

The landowner sought leave to appeal to the Supreme Court of Canada. Leave was granted on 26 November 2009 by a three member panel of the Court (McLachlin C.J.C., Abella and Rothstein JJ.).[239] No further decision has been rendered.

C. ENERGY RESOURCES CONSERVATION BOARD

The ERCB is the provincial regulator of Alberta's energy resources. It has a broad jurisdiction to regulate in respect of oil, natural gas, oil sands, coal, and pipelines and is responsible for regulating the safe, responsible, and efficient development of energy resources in Alberta. The following discussion highlights decisions of the Board rendered during the May 2009 to April 2010 time period.

1. ERCB Decision 2009-073: *AltaGas Ltd.: Applications for Two Pipeline Licences, An Amendment to a Facility Licence, and Approval for an Acid Gas Disposal Scheme — Pouce Coupe Field*[240]

AltaGas Ltd. (AltaGas) made four applications to the ERCB requesting: (1) approval to construct and operate a 12.7 km Level-2 pipeline for the transport of gas (maximum 5 percent H_2S content); (2) approval to amend the licence for an existing gas processing plant to add capacity to its sweet gas processing facility and allow it to handle a sour gas stream (maximum 5 percent H_2S content); (3) approval to construct and operate a 2.58 km Level-3 pipeline that would transport acid gas (maximum 80 percent H_2S content); and (4) approval to dispose of the acid gas (maximum 80 percent H_2S content) into the Belloy Formation through an existing well at LSD 9-10-81-13 W6M (the 9-10 well).

a. Proliferation

The main issue considered by the ERCB in this proceeding was proliferation, an issue of considerable public concern. This, linked with a difference of opinion as to whether the

236 *NEB Act*, *supra* note 4.
237 *Alliance*, *supra* note 232 at para. 49.
238 *Ibid.* at paras. 55-57.
239 *Smith v. Alliance Pipeline Ltd.*, [2009] 3 S.C.R. ix.
240 *AltaGas Ltd.: Applications for Two Pipeline Licences, An Amendment to a Facility Licence, and Approval for an Acid Gas Disposal Scheme — Pouce Coupe Field*, ERCB Decision 2009-073 (22 December 2009) [*AltaGas*]. All ERCB decisions, and the documents pertaining to them, can be found online: ERCB <http://www.ercb.ca/portal/server.pt?>.

ERCB directives at issue were mandatory, resulted in a minority decision being issued. Significantly, with respect to whether ERCB directives are mandatory in nature, the position of the majority was that "substantial" compliance by AltaGas is sufficient whereas the position of the minority was that the requirements of directives are mandatory and "substantial" compliance is not sufficient.[241]

The majority's findings in respect of proliferation related to ERCB *Interim Directive 2001-03: Sulphur Recovery — Guidelines for the Province of Alberta*[242] and *Directive 056: Energy Development Applications and Schedules*,[243] and CAPP's *Recommended Practices for Sour Gas Development Planning and Proliferation Assessment*,[244] each of which "direct, expect, or recommend evidence that demonstrates, as set out in *ID 2001-03* … 'applicants have vigorously explored and assessed all existing facilities in the area that afford technically viable alternatives, regardless of ownership or interest,' in order to avoid or minimize proliferation of sour gas facilities."[245] Ultimately, the majority was satisfied that AltaGas had taken adequate steps in this regard, including review of existing sour gas facilities, justification of social and environmental effects of the proposed new sour gas plant, evaluation of the feasibility of upgrading an existing sour gas processing facility in the area, and attempts to adequately consult with area residents regarding proliferation issues.[246]

While the majority found that there were certain "gaps in the proliferation assessment work performed by AltaGas," it nonetheless held that "AltaGas substantially met the proliferation requirements of the Board."[247] Significantly, the majority seemed to suggest that the requirements of its directives might not be mandatory, stating that "[a]ssuming for the sake of argument that *ID 2001-03,* the proliferation provisions of *Directive 056* … had the force of regulation, an application that fails to contain information prescribed by regulation can nonetheless be considered and approved by the Board."[248] In reaching this conclusion the majority relied on s. 10(4) of the *Oil and Gas Conservation Act*, which states:

> If a regulation under subsection (1)(a) has prescribed the information to be included in or to accompany an application pursuant to a given provision of the Act or the regulations, the Board is not precluded from considering or acting on an application pursuant to that provision that does not contain that information or from requiring additional information.[249]

In contrast, the minority stated that the requirements of *ID 2001-03* and *Directive 056* were mandatory, and that it was not the case that AltaGas had to only "substantially" meet the proliferation requirements.[250] The minority found that the assessment of needs and

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241 *Ibid.* at 26-27.
242 ERCB, *Interim Directive 2001-03: Sulphur Recovery — Guidelines for the Province of Alberta* (Calgary: ERCB, 2001) [*ID 2001-03*].
243 ERCB, *Directive 056: Energy Development Applications and Schedules* (Calgary: ERCB, 2008) [*Directive 056*].
244 CAPP, *Recommended Practices for Sour Gas Development Planning and Proliferation Assessment*, Publication Number 2004-0003 (Calgary: CAPP, 2004), online: CAPP <http://www.capp.ca/getdoc.aspx?Docid=74373&DT=PDF>.
245 *AltaGas*, *supra* note 240 at 9.
246 *Ibid.* at 9-17.
247 *Ibid.* at 9.
248 *Ibid.*
249 R.S.A. 2000, c. O-6 [*OGCA*].
250 *AltaGas*, *supra* note 240 at 26.

alternatives filed by AltaGas failed to comply with the ERCB requirements. According to the minority, the "need" for a project is distinct from the issue of "proliferation." The minority noted that just because a project is found to be in the public interest does not mean that there will not be site-specific impacts, and it is the duty of the ERCB to ensure that such "impacts are mitigated to an appropriate and acceptable level."[251] In coming to the conclusion that AltaGas failed to meet ERCB requirements with respect to proliferation, the minority stated that an applicant must provide extensive evidence "showing all the reasons why an expansion of an existing gas plant is required. A critical part of such documentation is the impact … on surface disturbance and the people affected by this activity."[252]

The minority was particularly critical of AltaGas's assessment of upgrading an existing Spectra Energy Midstream Corp. (Spectra) sour gas facility in the area, as the hypothetical specifications posed to Spectra by AltaGas in assessing the Spectra facility included whether the Spectra facilities could process 18 MMcfd of sour gas with an H_2S content of 5 percent.[253] The minority questioned how realistic the hypothetical was, considering AltaGas "did not expect gas containing 5 percent, since its [gas processing] contract … indicated that it would only be handling gas up to 2 per cent H_2S."[254] The minority also found that AltaGas had taken no steps to discuss forging commercial partnerships with related operators, such as Spectra.[255]

With respect to consultation, unlike the majority, the minority disagreed that local stakeholders had "hijacked" AltaGas's consultation meetings and instead held that AltaGas had failed to consult and involve local residents to examine their evaluation of alternatives to their specific plant expansion.[256] The minority considered this a major deficiency and found that the evidence demonstrated that "reviews and input from the residents were either very cursory or likely did not take place at all."[257] Other deficiencies found by the minority included a lack of information regarding pipelines associated with the alternatives considered[258] and an inadequate consideration of the social and environmental impacts of a proposed new sour gas plant within 15 km of an existing sour gas processing plant.[259]

While the majority of the ERCB granted the applications, the minority concluded that "AltaGas did not 'carefully' follow many of the mandatory prerequisites required in both *ID 2001-03* and *Directive 056* with respect to the issue of proliferation, and for this reason AltaGas's application for a licence to expand its existing sweet gas processing plant to a sour gas processing plant should be denied."[260]

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251 *Ibid.* at 19, citing *Compton Petroleum Corp.: Applications for Licences to Drill Six Critical Sour Natural Gas Wells, Reduced Emergency Planning Zone, Special Well Spacing, and Production Facilities — Okotoks Field*, EUB Decision 2005-060 (22 June 2005) at 13.
252 *AltaGas*, *ibid.* at 26.
253 *Ibid.* at 19.
254 *Ibid.* at 20.
255 *Ibid.* at 20, 23.
256 *Ibid.* at 21-22.
257 *Ibid.* at 27.
258 *Ibid.* at 24-25.
259 *Ibid.* at 22.
260 *Ibid.* at 27.

b. Acid Gas Disposal Well

In contrast to the Board's consideration of proliferation issues, issues related to the proposed 9-10 well were dealt with fairly summarily by the Board. The Board largely accepted AltaGas's proposal, including the location of the disposal well,[261] and its evidence that the well would meet ERCB requirements to ensure hydraulic isolation of the injected acid gas from the surface to disposal in the Belloy Formation.[262] However, the Board did require that AltaGas conduct cement bond logs for wells that had been cased into the Belloy Formation within the area of possible acid gas formation[263] and imposed a lower maximum wellhead injection pressure than sought by AltaGas.[264]

c. Public Safety

The ERCB held that AltaGas's dispersion modelling was deficient and did not consider terrain effects. The Board accepted interveners' expert evidence that the Alberta Ambient Air Quality Objectives (AAAQO) for SO_2 would not be met by AltaGas' proposed flare system. The Board required that AltaGas provide further modelling that accounted for terrain effects or modelling based on a different flare system and operational controls capable of achieving the AAAQO.[265] The interveners also expressed significant concern regarding the amount of flaring that had occurred at AltaGas' plant. The Board found that "even after implementing a flare management program, a significant flaring event occurred."[266]

Therefore, as a condition of approval, the Board required "AltaGas to advise the ERCB of any flaring events greater than two hours" in duration and provide a report every six months, until AltaGas demonstrates "to the satisfaction of the ERCB that it can limit flaring" and "that the measures AltaGas is undertaking are effective in reducing flare volumes and frequency."[267] The Board also imposed a number of additional conditions with respect to AltaGas's proposed emergency response plan (ERP), including the undertaking of a detailed consultation and notification program (as the Board found that information provided about various issues, such as sheltering in place and evacuation, was not sufficient); provision of a detailed public involvement documentation for each resident to be included in the copy of the updated ERP to be filed with the ERCB;[268] the inclusion in the ERP of aspects of the municipal development approval agreement related to the mitigative measures taken to ensure the viability of egress routes during winter months;[269] and the holding of an ERP exercise prior to the commencement of operations.[270]

261 *Ibid.* at 28.
262 *Ibid.* at 29.
263 *Ibid.* at 29-30.
264 *Ibid.* at 31.
265 *Ibid.* at 36.
266 *Ibid.* at 38.
267 *Ibid.* at 38-39.
268 *Ibid.* at 43.
269 *Ibid.* at 44.
270 *Ibid.* at 45.

d. Public Consultation and Other Matters

While the ERCB found that AltaGas had met the minimum consultation requirements set out in *Directive 056*, it expressed some concern over how AltaGas handled two major flaring events and a venting event and pointed to this as a major factor in the erosion of the relationship between AltaGas and affected residents.[271] The ERCB suggested that AltaGas would need to make significant efforts to remedy the situation with landowners and rebuild trust, and also noted that approval of AltaGas' updated ERP would likely depend on how successful AltaGas was in repairing the lines of communication.[272]

The ERCB also briefly addressed a number of other issues including categorizing applications as routine and non-routine,[273] pipeline integrity,[274] AltaGas' compliance history,[275] water drainage, noise, lights, and land values.[276]

2. ERCB DECISION 2010-005: *BEARSPAW PETROLEUM LTD. AND SIRIUS ENERGY INC.: APPLICATIONS FOR VARIATION OF COMPULSORY POOLING ORDER — DRUMHELLER FIELD*[277]

Pursuant to s. 82(2)(b) of the *OGCA*, the Board may hold a public hearing to consider a variation, amendment, or termination of a compulsory pooling order if "a well required by the order to be drilled is not drilled within 6 months of the date of the order."[278] In the Board's hearing process leading to *Sirius*, the Board was required to interpret an existing pooling order to determine whether the drilling of each zone had to be drilled and completed within the six-month period.

The first numbered clause of the existing order provided as follows: "All tracts within Section 11 of Township 29, Range 19, West of the 4th Meridian [Section 11], shall be operated as a unit to permit the production of gas from the Medicine Hat Sand, the Second White Speckled Shale, the Viking Formation, and the Upper Mannville Formation, through a well to be drilled in Legal Subdivision 10."[279]

The second numbered clause of the order required that "the operator drill and complete 'a well in the drilling spacing unit as described in clause 1 hereof' within six months following the date of the order."[280]

Bearspaw Petroleum Ltd. (Bearspaw) argued that under the pooling order the operator had six months to drill and complete any or all of the specified formations, "and at the end of the six months only those formations that had been drilled and completed would be considered

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271 *Ibid.* at 53.
272 *Ibid.* at 54.
273 *Ibid.*
274 *Ibid.* at 45-47.
275 *Ibid.* at 48-51.
276 *Ibid.* at 54-56.
277 *Bearspaw Petroleum Ltd. and Sirius Energy Inc.: Applications for Variation of Compulsory Pooling Order — Drumheller Field*, ERCB Decision 2010-005 (9 February 2010) [*Sirius*].
278 *Supra* note 249.
279 *Sirius*, *supra* note 277 at 6.
280 *Ibid.*

pooled."[281] Bearspaw argued that as Sirius Energy Inc.'s (Sirius) predecessor only drilled and completed the Glauconitic Sandstone within the six months specified in the order; the Medicine Hat Sand and Second White Specks formations in Section 11, which were drilled and completed later, were not under common ownership and therefore gas produced from these formations "was contrary to the legislation."[282]

The Board found that the proper interpretation of the pooling order was that the defined drilling spacing unit (DSU) included all tracts within Section 11. The reference in the order to "the" unit or "a" unit confirmed that there was a single DSU within Section 11 and not four distinct DSUs as suggested by Bearspaw. Despite the fact that all zones were not drilled and completed within the six-month period, the Board found that the requirement for drilling and completion of the well in the unit was satisfied within the time period noted and that all zones identified in the pooling order were therefore pooled as a unit for the production of gas from Section 11.[283]

The Board further considered which of the two competing applicants (Sirius or Bearspaw) should be named operator of the well. The Board noted that "its normal practice is to name the licensee of the well as operator unless compelling circumstances indicate otherwise."[284] Further, unit shares "should not dictate the designation of operatorship in preference to the licensee of the well in the DSU."[285] While Sirius had withheld some of Bearspaw's share of production from the pool, the Board was persuaded by Sirius's explanations and assurances given during the hearing that Sirius intended to act as a responsible operator.[286] The Board was not convinced that exceptional circumstances existed to deviate from the normal practice of appointing the licensee of the well as operator of the pool.

3. ERCB DECISION 2009-061: *SUNSHINE OILSANDS LTD. AND TOTAL E&P CANADA LTD.: APPLICATIONS FOR INTERIM SHUT-IN OF GAS — LIEGE FIELD, ATHABASCA OIL SANDS AREA*[287]

Where production from a gas well is putting bitumen at risk of sterilization, the appropriate test to be used for determining whether interim shut-in should be granted pending a final determination of the issue is whether there was potential for a "significant waste of bitumen resources during the period required to consider the main application."[288]

In *Sunshine*, the Board affirmed its prior determinations that a strict application of the tripartite test used in civil litigation is not the appropriate basis upon which to consider an interim shut-in application. Further, there is no requirement for the Board to consider the balance of convenience between the parties, or to conclusively determine irreparable harm.[289] Rather, the Board's focus is on the potential for the bitumen to be wasted. In this regard, in

281 *Ibid.* at 3.
282 *Ibid.*
283 *Ibid.* at 6-7.
284 *Ibid.* at 7.
285 *Ibid.* at 8.
286 *Ibid.*
287 *Sunshine Oilsands Ltd. and Total E&P Canada Ltd.: Applications for Interim Shut-in of Gas — Liege Field, Athabasca Oil Sands Area,* ERCB Decision 2009-061 (15 October 2009) [*Sunshine*].
288 *Ibid.* at 2.
289 *Ibid.*

determining whether to issue an interim shut-in order, the proper considerations are: whether the bitumen is potentially recoverable (not commercially recoverable); whether there was "communication between the gas and bitumen intervals"; the "effect of gas production on bitumen recovery by steam-assisted gravity drainage (SAGD)"; the "urgency for interim shut-in of gas"; and the "need to shut-in additional intervals."[290]

Following a written hearing, the Board found that the evidence established that there was communication between the gas and bitumen in multiple pools.[291] The Board applied an expanded definition of "potentially recoverable bitumen," which included "consideration of the long-term development of bitumen resources" and the bitumen that is exploitable with the use of "reasonably foreseeable technology and economic conditions."[292] On this basis, the Board also found that each of the pools at issue had potentially recoverable bitumen.

While the Board recognized that the estimated reduction of pressure over the one-year interim period would normally be considered modest, the Board found that, in the circumstances, the reduction was in fact significant because the current reservoir pressure was very low.[293] As a result, "producing associated gas and thereby reducing the reservoir pressure presents an unacceptable risk to SAGD bitumen recovery."[294] The Board therefore determined that natural gas production presented a significant risk to future in situ bitumen recovery and would be shut-in on an interim basis pending the final determination of issues in the ERCB proceeding. In addition to the shut-in of wells as applied for, the Board exercised its jurisdiction pursuant to s. 3(5) of the *Oil Sands Conservation Regulation*,[295] and its conservation mandate, to shut-in additional wells on an interim basis, given that gas production is dealt with by the Board on a pool basis.[296]

4. ERCB DECISION 2009-072: *TRILOGY BLUE MOUNTAIN LTD.: APPLICATIONS FOR A WELL AND A PIPELINE LICENCE — PEMBINA FIELD*[297]

Trilogy Blue Mountain Ltd. (Trilogy) applied to the Board under s. 2.020 of the *Oil and Gas Conservation Regulations*[298] for a licence to drill a well (the 14-23 well), and under Part 4 of the *Pipeline Act*,[299] for approval to construct a pipeline of 140 m in length for the purpose of transporting gas from the 14-23 well to a nearby tie-in point. Two landowner groups participated in the hearing as there was no agreement amongst area landowners as to the location of the 14-23 well or the alternative locations proposed by some of the landowners and explored by Trilogy.

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290 *Ibid.* at 3.
291 *Ibid.* at 3-5.
292 *Ibid.* at 6, citing *Phase 3 Final Proceeding Under Bitumen Conservation Requirements in the Athabasca Wabiskaw-McMurray*, EUB Decision 2005-122 Addendum (21 December 2005) at 7.
293 *Sunshine*, *ibid.* at 7.
294 *Ibid.*
295 Alta. Reg. 76/88.
296 *Sunshine*, *supra* note 287 at 8.
297 *Trilogy Blue Mountain Ltd.: Applications for a Well and a Pipeline Licence — Pembina Field*, ERCB Decision 2009-072 (15 December 2009) [*Blue Mountain*].
298 Alta. Reg. 151/71 [*OGCR*].
299 R.S.A. 2000, c. P-15.

The 14-23 well and related pipeline were proposed to be located on an existing wellsite in the vicinity of Battle Lake. Resource development in the Battle Lake area is subject to the *Battle Lake Watershed Development Planning Pilot Project: Report of the Multistakeholder Pilot Project Team*,[300] which recommends a three-tiered approach for identifying protection priorities for lands within the Battle Lake Watershed. Pursuant to the *Battle Lake Report*, Tier 1 lands are "key environmentally sensitive areas where new disturbance should be avoided."[301] In addition, "operators are expected to investigate alternative approaches for oil and gas development and select those areas that avoid" Tier 1 areas.[302] The existing wellsite at the applied-for location was outside of the environmentally sensitive Tier 1 area.

At the hearing, Trilogy argued that "it had evaluated all existing surface leases and potential new surface locations within 800 m of the proposed bottomhole location" for the 14-23 well.[303] Trilogy concluded that the 14-23 wellsite was the most suitable location among alternatives available having regard to various considerations, including the *Battle Lake Report.* Although four alternative well surface locations were examined at the hearing and the Board noted that it heard "a great deal of evidence regarding the suitability of other sites," the Board concluded that there was insufficient information to determine whether Trilogy's proposed 14-23 wellsite location was "the more appropriate location for the proposed well and pipeline."[304]

Blue Mountain raises the issue of whether the applied-for location must be demonstrated to be acceptable or whether it must be superior to all other potential locations, as well as the degree to which the onus falls on the applicant, or interveners, in that regard. *Blue Mountain* also raises the issue of whether it is desirable, in some circumstances, to apply for multiple wellsite locations:

> The Board notes that in the normal course of business, companies are encouraged to bring forward applications for a single location, thereby minimizing the number of local landowners who may be inconvenienced by the applications and a subsequent hearing. The Board is also mindful of the fact that proposing multiple locations may have the effect of pitting members of a community against one another, as parties take positions that may be contrary to those of their neighbours. However, in this case, applications for alternative competing sites would have been helpful to the Board.
>
> When it is clear that the location of a site will be a principal issue at a hearing, companies should consider bringing forward applications for alternative locations, so that those alternatives can be fully explored during the course of the hearing.[305]

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300 EUB, *Battle Lake Watershed Development Planning Pilot Project: Report of the Multistakeholder Pilot Project Team* (Calgary: EUB, 2006), online: ERCB <http://www.ercb.ca/docs/new/project/land/BattleLakeReport_200612.pdf> [*Battle Lake Report*].
301 *Ibid.* at iv.
302 *Ibid.*
303 *Blue Mountain*, *supra* note 297 at 8.
304 *Ibid.* at 14.
305 *Ibid.*

Future decisions may provide additional clarity on the evaluation criteria for alternative sites and when multiple applications are expected by the Board.[306]

5. ERCB DECISION 2009-051: *ENCANA CORPORATION: APPLICATIONS FOR THREE WELL LICENCES — SUFFIELD FIELD*[307]

In considering applications by EnCana Corporation (EnCana), pursuant to s. 2.020 of the *OGCR*,[308] to drill three vertical gas wells from surface locations on the federal Suffield Military Base (Suffield Base), the ERCB confirmed a prior ruling that it could not grant surface access to the land.[309] However, the Board did find, following a written process, that it had the authority and jurisdiction to approve the well licences, provided that it found issuance of the well licences to be in the public interest.[310]

The Board reviewed the history of the Suffield Base, located near Medicine Hat, confirming that a 1975 memorandum of agreement (the 1975 MOA) authorizing entry upon and use of the Suffield Base by Alberta for the purposes of natural gas production remained in force. This 1975 MOA affirmed that the ERCB would regulate oil and gas activities on the Suffield Base in the same manner that it did elsewhere in the province. The rights under the 1975 MOA were, at the time, held by EnCana.[311] The Board also identified a range standing order (RSO) issued by the Base Commander on 1 December 2008, which limited the maximum disturbance per section (DPS) to 16 surface locations. Notably, EnCana's proposed wells were located on sections that already exceeded the 16 DPS limit.[312]

In assessing the need for the issuance of the three well licences, the Board considered that the drilling of three wells would achieve resource conservation as they would result in incremental gas reserves being recovered. Further, the Board agreed with EnCana that drilling infill wells directionally from existing well surface locations would be less effective than vertical wells and would result in reduced recovery.[313]

In fulfillment of its mandate pursuant to s. 3 of the *Energy Resources Conservation Act*[314] regarding the public interest, the Board confirmed that it had the authority to issue the licences if it found that the issuance was in the public interest. Citing from *Polaris Resources Ltd.: Applications for a Well Licence, Special Gas Well Spacing, Compulsory Pooling, and*

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306 A similar issue was raised by the ERCB in the context of the routing of a pipeline proposed by Petro-Canada in the Sullivan field. After argument had been received, the ERCB requested that Petro-Canada provide "specific information clarifying the comparison done by the company of its preferred pipeline routes to certain other alternatives referenced" in Petro-Canada's evidence. The ERCB set a process for further argument on the issues raised: ERCB, News Release, "ERCB Requests More Information from Petro-Canada Relating to Pipeline Routing Options for its Proposed Sullivan Field Development" (22 September 2009).

307 *EnCana Corporation: Applications for Three Well Licences — Suffield Field*, ERCB Decision 2009-051 (25 August 2009) [*EnCana*].

308 *Supra* note 298.

309 *EnCana*, *supra* note 307 at 6.

310 *Ibid.* at 7.

311 *Ibid.* at 2-3.

312 *Ibid.* at 4-5.

313 *Ibid.* at 12.

314 R.S.A. 2000, c. E-10 [*ERCA*].

Flaring Permit — Livingstone Field,[315] regarding its public interest mandate, the Board stated as follows:

> Consideration of the public interest is in essence a question of finding the appropriate balance between the benefits of the proposed project and the potential risks of the project to the public and the environment. Where the potential for risk outweighs the possibility of gain, the Board will find that the specific proposed project is contrary to the public interest.
>
> As all projects may have some element of risk, a great deal of the Board's attention must be focused upon the level of risk and the ability and willingness of the applicant to mitigate or eliminate such risks. An applicant's ability to take the appropriate measures to deal with risk is therefore critical to the Board's final determination as to whether the project can be found to be in the public interest.[316]

The Board held that the 16 DPS limit imposed by the RSO did not in and of itself constrain the ERCB's jurisdiction but was part of the Board's public interest consideration.[317] Given that the wells were to be located within a military base used for live fire exercises, the Board noted that its public interest mandate "must also take into account the risk the wells pose to the future viability of ongoing military training in the application area," including consideration of the 16 DPS limit.[318]

In determining whether the wells were in the public interest, the Board took into consideration soils and vegetation, water and wetlands, wildlife, reclamation and land use, and military training.[319] While there were no major issues identified with respect to water and wetlands or wildlife, of particular concern to the Board were plant species that may be at risk, as well as vegetation damage and soil rutting due to the use of multiple access routes.[320] In finding that the three wells would "have a low impact on native prairie grassland ecosystems," the Board noted that any effects would "be effectively mitigated by the best practices proposed" in the application and environmental protection plan.[321]

Notably, the Board acknowledged that "there is a regulatory gap on the Suffield Base with respect to reclamation."[322] However, it accepted the reclamation process proposed by EnCana whereby reclamation would commence immediately upon the well being drilled and the site being cleaned up. The reclamation would include seeding disturbed areas, regular inspections, and ongoing monitoring by EnCana, the Department of National Defence (DND), and the Suffield Environmental Advisory Committee (SEAC).[323]

In assessing the public interest, the Board also addressed the impact of the wells on military land use and training, noting that the DND concerns regarding safety and operations related to the drilling, the impact on military operations, and the overall sustainability of the

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315 EUB Decision 2003-101 (16 December 2003) at 3.
316 *EnCana*, *supra* note 307 at 8.
317 *Ibid.*
318 *Ibid.*
319 *Ibid.* at 30-35.
320 *Ibid.* at 31
321 *Ibid.* at 32.
322 *Ibid.* at 33.
323 *Ibid.* at 34.

Suffield Base as a result of environmental effects. While the Board recognized that the 1975 MOA authorized the Base Commander to issue orders and instructions regarding the location and engineering design of well structures, no such orders had yet been made, implying that the current locations of wells did not pose a risk to the safety of personnel or equipment.[324] The Board disagreed with the DND that the only solution to its concerns was the implementation of the DPS limit imposed by the RSO.[325] As a result, the Board found that approval of the three applied-for wells was in the public interest.

Notably, the Board recommended that future conflicts arising with respect to development on the Suffield Base be dealt with through the process contemplated by the 1975 MOA. Specifically, the Board recommended that in the case of environmental concerns, the Base Commander should approach SEAC, which could resolve issues efficiently and effectively. Further, the Board recognized that the Base Commander may make use of their ability to order "relocation or redesign of wells, pipeline, or facilities for the protection and safety of personnel and equipment."[326] While the Board would continue to rule on future contested applications, it recommended that the parties re-engage in a dispute resolution process to resolve outstanding concerns.[327]

6. ERCB DECISION 2009-037: *OMERS ENERGY INC.: SECTION 39 REVIEW OF WELL LICENCES NO. 0336235 AND NO. 0392996 — WARWICK FIELD*[328]

In August 2005 and January 2008, the Board issued two licences to OMERS Energy Inc. (OMERS), each for a single well. A review request by Montane Resources Ltd. (Montane) pursuant to s. 39 of the *ERCA* based on whether OMERS held a valid and subsisting lease for purposes of the issuance of the well licences was granted by the Board.[329] Montane argued that OMERS' lease, which was dated 8 February 2001, had terminated on its terms as a result of a well being shut-in and incapable of production.[330] The Board focused on the interpretation of several clauses in the lease including the habendum clause and the suspended wells clause. In its interpretation, the Board held that it must give effect to the terms of the lease "according to the plain and ordinary meaning of the words of the lease," unless such an interpretation would result in absurdity.[331]

The habendum clause of the lease held that the lease was valid for a period of five years, and upon expiry it would be continued if "operations"[332] were being conducted on the land "with no cessation for more than 90 consecutive days."[333] In addition to the habendum clause, the suspended wells clause provided circumstances under which the lease would continue notwithstanding that operations were not being conducted on the lands. For example, the

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324 *Ibid.*
325 *Ibid.* at 35.
326 *Ibid.* at 35-36.
327 *Ibid.* at 36.
328 *OMERS Energy Inc.: Section 39 Review of Well Licences No. 0336235 and No. 0392996 — Warwick Field*, ERCB Decision 2009-037 (12 May 2009).
329 *Ibid.* at 1.
330 *Ibid.* at 4.
331 *Ibid.* at 5.
332 "Operations" were defined in the lease to include "drilling, testing, completing, reworking, recompleting, deepening, plugging back or repairing the well or equipment … or injecting substances," or "any acts for or incidental to any of the foregoing" in attempts to increase or maintain production (*ibid.* at 8).
333 *Ibid.* at 5.

lease would continue if a well on the lands was shut-in or suspended but was capable of producing the leased substances. Alternatively, in the absence of the capability to produce, the lease would continue if actual operations were commenced on the lands "with no cessation of more than 90 consecutive days between successive operations."[334] As the well had been shut-in for more than 90 days, continuation of the lease was dependent on the Board's interpretation of the phrase "capable of producing the leased substances."[335]

The Board found that the phrase "capable of producing" required a shut-in or suspended well to have the ability to produce "in its existing configuration and state of completion," without further "operations" being required.[336] The Board clarified that in the circumstances of the lease, the phrase did not require "production in commercial amounts or paying amounts."[337] The Board interpreted the phrase "producing the leased substances" as requiring more than insignificant or miniscule amounts of production; "there must at least be some material, as in a meaningful, volume of production possible" in order for the lessee to extend the lease.[338] To find otherwise would, in the Board's view, be contrary to the parties' intentions.

The Board concluded that the phrase "capable of producing the leased substances" should "be interpreted to mean the demonstrated, present ability of a well on the lands to produce the leased substances in a meaningful quantity within the timeframes contemplated in the lease."[339] What is material or meaningful would depend on the relevant factors in each individual case. However, despite technical arguments put forth by OMERS, the evidence did not convince the Board that the well would have produced meaningful quantities if it were turned on. The primary issue with respect to the production capability of the well was the build-up of produced water in the wellbore. The Board concluded that the well required further "operations" to address the water loading situation before production of a meaningful amount of leased substances could occur.[340]

Based on the evidence presented, the Board found that there was no capability of producing the leased substances at the time the well was shut-in. As a result, the lease ended by its own terms, and OMERS did not have a valid lease for purposes of the well licences being issued. The Board suspended the well licences issued in August 2005 and January 2008, as OMERS failed to meet the requirement for common ownership throughout the DSU.[341]

OMERS applied for leave to appeal the ERCB decision, arguing *inter alia* that the Board "had no judicial guidance on the meaning of the phrase 'capable of producing the leased substances'" or erred in law by misinterpreting the phrase.[342] Leave was granted with respect

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334 *Ibid.*
335 *Ibid.* at 6.
336 *Ibid.* at 7.
337 *Ibid.* at 8.
338 *Ibid.* at 9.
339 *Ibid.*
340 *Ibid.* at 13.
341 *Ibid.* at 14.
342 *Omers Energy Inc. v. Alberta (Energy Resources Conservation Board)*, 2009 ABCA 273, [2009] A.J. No. 873 at para. 4 (QL).

to the following question: "[d]id the Board err in its interpretation of the phrase 'capable of producing the leased substances'?"[343] The appeal is scheduled to be heard in October 2010.

7. ERCB DECISION 2010-016: *BOWOOD ENERGY LTD: SECTION 40 REVIEW OF WELL LICENCE NO. 0413339*[344]

ERCB Bulletin 2006-24 states that "the subsurface clustering of wellbores is inappropriate," and therefore operators are expected "to place their wells in a manner that will efficiently drain the [respective] reservoir."[345] Bowood Energy Ltd. (Bowood) applied for, and was granted, approval to drill a second gas well in the same legal subdivision as one of its existing wells. Advantage Oil and Gas Ltd. (Advantage), as an adjacent mineral rights holder, applied pursuant to s. 40 of the *ERCA* for a review and variance of the decision to grant the approval to drill the second well. Advantage also requested a stay of the Bowood well pending a review hearing. Advantage argued *inter alia* that the Bowood well licence "constituted inappropriate subsurface clustering of wellbores."[346]

The Board set the matter for a hearing as Advantage's equity interest was potentially adversely affected by the close proximity of Bowood's wellbores. However, prior to the hearing, Bowood notified the ERCB that it intended to abandon its initial well and therefore requested that the Board make a preliminary determination dismissing Advantage's review on the basis that Advantage was no longer directly and adversely affected on the basis of clustering.[347]

As the Board had granted the review application on the issue of clustering, a determination was required as to whether an abandoned well should be included within the term "clustering."[348] The Board noted that the clustering of wells created conservation and equity issues and as such should be avoided through the use of industry best practices, without the involvement of the Board.[349] Clustering may "be an issue where two or more producing wells in a pool are located in close proximity to one another," whereby they "enable a company to exceed its equitable production from the pool."[350] However, the Board clarified that clustering is not present simply because wells have been drilled in close proximity; clustering requires that both wells are "producing at the same time or [are] able to produce simultaneously."[351]

Given that Bowood had abandoned the initial well and was no longer able to produce from it, the Board found that Advantage's equity interest was no longer potentially adversely affected.[352] On this basis, the Board dismissed the review application.

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343 *Ibid.* at para. 8.
344 *Bowood Energy Ltd.: Section 40 Review of Well Licence No. 0413339*, ERCB Decision 2010-016 (23 March 2010) [*Bowood*].
345 ERCB, Bulletin 2006-24, "Well Spacing Amendment Regulation Regarding Changes to Reservoir-Related Well Spacing Regulations, Application Requirements, and Application Review Process" (7 July 2006) at 10.
346 *Bowood*, *supra* note 344 at 1.
347 *Ibid.* at 2.
348 *Ibid.* at 3.
349 *Ibid.* at 4.
350 *Ibid.*
351 *Ibid.*
352 *Ibid.* at 5.

8. ERCB DECISION 2009-050: *NEXXTEP RESOURCES LTD.: POOL DELINEATION APPLICATION, REDESIGNATION OF THE LOWER MANNVILLE C POOL TO ROCK CREEK — WILSON CREEK FIELD*[353]

In the context of reviewing an application to have a pool redesignated, the ERCB discussed the evidentiary test applicable. While the application was ultimately approved, the ERCB panel members were unable to agree on whether Nexxtep Resources Ltd. (Nexxtep) had met the appropriate evidentiary test, with the minority finding that insufficient evidence had been provided to allow the redesignation.

Nexxtep applied to the ERCB pursuant to s. 33(1)(d) of the *OGCA* to redesignate the Wilson Creek Lower Mannville C Pool (C Pool) in sections 16 and 21 of 21-43-4W5M to the Jurassic Creek Formation. Nexxtep also requested that the ERCB implement consequential measures as contained in ss. 16 and 25 of the *OGCA*, including the immediate cancellation or suspension of the licence for the 100/2-16-043-04W5/02 well (the 00/2-16 well), owned and operated by Talisman Energy Inc. (Talisman). Talisman and Bonavista Petroleum Ltd. (Bonavista) submitted objection letters and participated in the hearing.

Pool designation is determined by geological interpretation of the strata and reservoir engineering data.[354] However, *Nexxtep* is significant in that the ERCB considered arguments by both Talisman and Bonavista that the burden of proof to overturn a long-standing pool designation was high and exceeded the balance of probabilities that ordinarily applies in the context of hearings before administrative tribunals. The Board disagreed.[355]

Relying on the comments of the Alberta Court of Appeal in *Gannon Bros. Energy Ltd. v. Alberta (Energy and Utilities Board)*,[356] Nexxtep argued that the test to be applied is the civil law balance of probabilities. In *Gannon Bros.*, the Court stated that the standard of proof was to persuade the ERCB "not beyond a reasonable doubt, but simply to persuade them."[357] Nexxtep also submitted that a number of ERCB decisions made it clear that the test to be applied to a pool designation question is the balance of probabilities.[358]

Talisman argued that the ERCB's power under s. 33 of the *OGCA*[359] to designate a pool is discretionary, not mandatory. Accordingly, Talisman argued that the ERCB should consider all relevant factors related to a specific application in determining the strength of the evidence needed to change a pool designation. Talisman was of the view that the Board should not change its orders lightly, given that the oil and gas industry relies on the orders in governing their affairs. Changing orders "without substantial evidence would reduce the

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353 *Nexxtep Resources Ltd.: Pool Delineation Application, Redesignation of the Lower Mannville C Pool to Rock Creek — Wilson Creek Field*, ERCB Decision 2009-050 (7 August 2009) [*Nexxtep*].

354 *Ibid.* at 2.

355 *Ibid.* at 6.

356 (1996), 178 A.R. 302 (C.A.) [*Gannon Bros.*].

357 *Ibid.* at para. 6.

358 *Nexxtep*, *supra* note 353 at 4.

359 Section 33 of the *OGCA*, *supra* note 249, reads: "The Board may, by order, … designate a pool by describing the surface area vertically above the pool and by naming the geological formation, member or zone in which the pool occurs or by some other method of identification that the Board in any case considers suitable."

certainty of the Board's orders."[360] Talisman also argued that the concept of a high onus was appropriate where a third party's rights (in this case those of Bonavista) would be altered based on a redesignation order for the pool. Finally, Talisman argued that as the "redesignation of the pool would most likely result in prolonged shutdown of production while interests were worked out, redesignation was inconsistent with the Board's mandate to oversee the orderly, economic, and efficient maximization of Alberta's oil and gas resources," and as such, Nexxtep's evidence must be substantial and include technical certainty in order to justify redesignation.[361]

Unlike Talisman, Bonavista acknowledged that there was no clear authority supporting the proposition that the evidentiary test is anything other than the balance of probabilities, but argued that the standard of proof should be distinguished from the degree of proof. Bonavista submitted that the Board should apply a rigorous degree of proof in terms of evidence needed before changing a pool designation. The degree of proof "should be high, given the complexity of the materials and the possible consequences."[362]

The ERCB dismissed the arguments of Talisman and Bonavista in concluding that the burden of proof in an administrative hearing is on the balance of probabilities. According to the ERCB, the evidentiary test requires the ERCB to "weigh all the evidence that it hears and its decision must be based on the balance of the evidence."[363] The ERCB specifically relied on the Supreme Court of Canada's description of the balance of probabilities in *R. v. Clark*,[364] stating: "there has to be a preponderance of evidence to show that the conclusion the applicant seeks to establish is substantially the most probable of the possible views of the facts presented to the Board."[365] Finally, the ERCB held that Nexxtep was not required to provide conclusive evidence in order for a determination to be made in its favour.[366]

Interestingly, applying the balance of probabilities test to the evidence resulted in differing conclusions amongst the Board Members as to whether Nexxtep had established sufficient evidence to support its application for a pool redesignation order. A majority of the ERCB concluded that the application for redesignation of the interval in question should be granted. The majority acknowledged the "coordinated, systematic, and multidisciplinary approach provided by the applicant in the presentation of its evidence" as being helpful in meeting the evidentiary burden of proof.[367]

While the minority Board Member also agreed that the evidentiary test to be applied to the application was the balance of probabilities, he was of the view that the evidence provided by Nexxtep did not support a redesignation of the interval. Based on his findings, the minority Board Member believed that the current designation of the interval in question was accurate or, alternatively, that insufficient evidence had been provided to suggest otherwise. It appears that the minority Board Member was likely influenced by the fact that

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360 *Nexxtep*, *supra* note 353 at 5.
361 *Ibid.*
362 *Ibid.*
363 *Ibid.* at 6.
364 (1921), 61 S.C.R. 608 at 616.
365 *Nexxtep*, *supra* note 353 at 6.
366 *Ibid.*
367 *Ibid.* at 25.

redesignating the C pool would have "significant consequences for the parties involved" and that "elements of this decision will influence future zone and pool designations in this area."[368]

9. ERCB DECISION 2009-064: *COMPTON PETROLEUM CORPORATION: APPEAL OF ERCB HIGH RISK ENFORCEMENT ACTION 1*[369]

Section 2.2.1(2) of *Directive 056*[370] requires sweet gas well licence applicants to include in consultation and notification requirements all parties within 100 m of a proposed well. As well, s. 2.2.1(3) requires an applicant to meet consultation and notification requirements with respect to all parties whose rights may be directly and adversely affected, including parties with a direct interest in land. Section 2.2.1(4) requires that an applicant "also include those people that it is aware of who have special needs or concerns and reside beyond the consultation and notification radius."[371] A failure to meet these consultation and notification requirements may result in a High Risk Enforcement Action being issued in accordance with *Directive 019: ERCB Compliance Assurance — Enforcement*.[372]

The Graffs, who owned land 180 m from a well applied for by Compton Petroleum Corporation (Compton) and resided 17 km from the well, had a history of objecting to oil and gas activity in the area, of which Compton was aware. Compton failed to include the Graffs in its consultation and notification measures for the well. Compton's failure to do so resulted in the issuance of a High Risk Enforcement Action by Board staff. Compton appealed and, as a result, the Board was required to determine the meaning of "people who have special needs or concerns and reside beyond the consultation and notification radius" as outlined in s. 2.2.1(4) of *Directive 056*. It was "not disputed that Compton was aware of the Graffs, the nature of their concerns, and the location of their residence in relation to the proposed wells."[373] At issue was compliance with s. 2.2.1(4) of *Directive 056*.

The Board noted that "[s]ection 2.2.1(4) refers specifically to residents, not landowners."[374] As such, an enforcement action due to non-compliance with s. 2.2.1(4) cannot be based on proximity of a project to lands.[375] Further, the application of s. 2.2.1(4) "does not depend upon a finding of special needs, but rather a finding of knowledge by the applicant of people with special needs or concerns," even if the applicant disagrees with the special need or concern raised and those special needs or concerns are only an assertion.[376] As Compton was aware that the Graffs had raised concerns asserting special needs, the Board agreed that the Enforcement Audit Section of the ERCB appropriately found Compton to be aware of a party with special concerns that resided outside the applicable radius. [377]

368 *Ibid.* at 37.
369 *Compton Petroleum Corporation: Appeal of ERCB High Risk Enforcement Action 1,* ERCB Decision 2009-064 (3 November 2009)[*Compton*].
370 *Supra* note 243.
371 *Ibid.*
372 ERCB, *Directive 019: ERCB Compliance Assurance — Enforcement* (Calgary: ERCB, 2007) [*Directive 019*].
373 *Compton, supra* note 369 at 8.
374 *Ibid.*
375 *Ibid.* at 10.
376 *Ibid.* at 8.
377 *Ibid.* at 9.

However, although the Board found that Compton had knowledge of a person with a special concern, the Board agreed with Compton that s. 2.2.1(4) was open-ended and found that some measure of reasonableness must be applied in determining which landowners that reside beyond the radii indicated in *Directive 056* should be included in the consultation and notification process.[378] The Board concluded that "if the application of a requirement is unclear or if the result would be unreasonable," enforcement should not be undertaken.[379] In undertaking a prima facie assessment of the possible risks, based on the fact that the well was a sweet gas well and the fact that the Graffs' residence was 17 km from the well, the Board concluded that Compton should not reasonably be required to notify the Graffs of its applications. Further, it was reasonable for Compton to refer to previous decisions of the Board in analogous circumstances to determine an appropriate public involvement program. As a result, the High Risk Enforcement Action was inappropriate.[380]

10. ERCB DECISION 2009-041: *PENN WEST PETROLEUM LTD.: APPEAL OF ERCB HIGH RISK ENFORCEMENT ACTION 2*[381]

The depth of cover requirements prescribed by s. 20 of *Directive 066: Requirements and Procedures for Pipelines*[382] and s. 20 of the *Pipeline Regulation*[383] require operators to maintain at all times a minimum depth of cover over pipelines as specified in *Canadian Standards Association (CSA) Z662-07: Oil and Gas Pipeline Systems*; in the case of water crossings, a minimum of 1.2 m of earth cover is required.[384]

After a pipeline failure on 30 April 2008 that resulted in the release of produced fluids into a river, the Board issued a High Risk Enforcement Action 2 against Penn West Petroleum Ltd. (Penn West) for unsatisfactory depth of cover of a pipeline and failure to conduct the required right-of-way surveillance. Penn West appealed to the ERCB Corporate Compliance Branch on the basis that upon taking operatorship of the pipeline in September of 2007, it "did not have an opportunity to do right-of-way surveillance when the pipeline was not covered with snow."[385] Further, Penn West maintained that aerial surveillance conducted immediately after assuming operatorship indicated that there was no exposure of the pipe.[386] The ERCB Enforcement Advisor denied the appeal. Penn West appealed to the Board.

In denying Penn West's appeal, the Board noted that several actions and inactions of Penn West contributed to the failure. Operators cannot assume that conducting depth of cover inspections within one year of acquiring operatorship of a pipeline are adequate. The operator must do what is "prudent and advisable," and "[a]ny assumptions about the adequacy of

378 *Ibid.*
379 *Ibid.*
380 *Ibid.*
381 *Penn West Petroleum Ltd.: Appeal of ERCB High Risk Enforcement Action 2,* ERCB Decision 2009-041 (11 August 2009) [*Penn West*].
382 EUB, *Directive 066: Requirements and Procedures for Pipelines* (Calgary: EUB, 2005) at 12 [*Directive 066*].
383 Alta. Reg. 91/2005.
384 *Penn West*, *supra* note 381 at 1.
385 *Ibid.*
386 *Ibid.*

inspections of facilities acquired from another operator" are made at the operator's own risk.[387]

Specifically, the Board noted that the failure to conduct depth of cover inspections during the late summer and early fall of 2007, when there was ample time to do so, was a relevant factor in its decision.[388] A company cannot rely on the fact that it had recently acquired the pipeline from another operator, nor can it rely on a lack of information about the geography and snow cover in the area as justification for not conducting adequate inspections.[389] On this basis, the Board found that the depth of cover requirements are prescribed and that Penn West was not in technical compliance with the requirements.[390] The Board denied the appeal, holding that the High Risk Enforcement Action was appropriate.

D. ALBERTA SURFACE RIGHTS BOARD

The Alberta Surface Rights Board (SRB) is established under the *Surface Rights Act*.[391] Pursuant to its enabling legislation and regulations made thereunder, the SRB is authorized to resolve disputes between operators and landowners/occupants related to entry onto lands, annual reviews of compensation, damages, and recovery of compensation[392] in the context of energy activities (such as oil and gas developments), transmission lines, coal mines, and telephone lines. The SRB's jurisdiction extends to all land in Alberta, including both private and Crown land, except land within a Métis settlement[393] but does not apply to pipelines that are subject to regulation by the NEB.[394] A change in regulatory jurisdiction over the subject facility impacts the application of the *SRA*.[395]

The following discusses decisions of the SRB that will be of interest to those engaged in the energy industry.

1. *AIR PRODUCTS CANADA LTD. V. 1274664 ALBERTA LTD.*[396]

Section 12 of the *SRA* authorizes the Board to grant a right of entry order (ROE) in respect of wells, facilities, power lines, coal mines, and pipelines, if an operator and landowner/occupant cannot reach an agreement for access to the land.

387 *Ibid.* at 3.

388 *Ibid.* See also ERCB, Bulletin 2009-012, "Surveillance and Inspection of Pipeline Water Crossings" (14 April 2009), regarding requirements for addressing right-of-way surveillance for pipelines.

389 *Penn West*, *ibid.* at 4.

390 *Ibid.* at 3-4.

391 R.S.A. 2000, c. S-24 [*SRA*].

392 SRB, *Mandate and Roles Document* (Edmonton: SRB, 2009) at 4, online: SRB <http://www.surfacerights.gov.ab.ca/Content_Files/Files/SRBMandateandRolesDocument.pdf>.

393 *SRA*, *supra* note 391, s. 2.

394 See *Anderson Energy Ltd. v. Baron*, SRB Decision 2010/0073 (26 January 2010). All SRB decisions can be found online: SRB <http://www.surfacerights.gov.ab.ca/ordersdecisions/default.aspx>.

395 See *NOVA Gas Transmission Ltd. v. McCracken*, SRB Decision 2010/0072 (25 January 2010) [*McCracken*]. The SRB's jurisdiction extends not only to the granting of a right of entry order (ROE) but also to the termination of ROEs in certain circumstances pursuant to s. 28 of the *SRA*. In *McCracken*, relating to the TransCanada Alberta System, for example, the SRB rescinded an existing ROE following its determination that the NEB had assumed jurisdiction over the pipelines in respect of which the ROE had been granted. As the pipelines were now within federal jurisdiction, the SRB no longer had jurisdiction over the pipelines, or the applicable ROE.

396 SRB Decision 2009/0567 (16 December 2009) [*Air Products*].

In *Air Products*, the SRB considered an application by Air Products Canada Ltd. (Air Products) pursuant to s. 12(1)(c) of the *SRA* or, in the alternative, s. 12(3), requesting the issuance of a ROE not only in respect of a pipeline but also in respect of an access road for the pipeline. Section 12(1)(c) refers to right of entry to the surface of any land "for or incidental to the construction, operation or removal of a pipeline."[397] Air Products argued that, while s. 12(1)(c) did not specifically mention access roads, "the overall scheme of the *Act* allows for access to private land for the purpose of constructing a pipeline."[398] Further, and in the alternative, Air Products relied on s. 12(3) as authority for the SRB to grant a ROE "for mining or drilling operations from adjacent land."[399]

The Board denied the request insofar as it related to a request for a ROE for an access road. The SRB concluded that s. 12(1)(c) of the *SRA* did not specifically refer to a roadway in relation to a pipeline, and further that an access road is not "*incidental* to the construction, operation or removal of a pipeline," as outlined in the section. Similarly, s. 12(3) of the *SRA* did not authorize the SRB to grant a ROE for a roadway to a pipeline.[400]

While the SRB was not required to address the issue having regard to its conclusions in respect of the scope of ss. 12(1) and (3) of the *SRA*, the SRB also addressed the underlying ERCB permit issued in respect of the pipeline, stating that it was not convinced that a roadway was included in the ERCB pipeline permit.[401] Assuming that the SRB was correct, given that the SRB's jurisdiction requires that it issue a ROE that is consistent with the ERCB authorization, the SRB would be without jurisdiction to issue a ROE in respect of a roadway unless it was included in the ERCB authorization.[402]

2. *AIR PRODUCTS CANADA LTD. V. FORT INDUSTRIAL ESTATES LTD.*[403]

While ROEs are generally granted as a matter of course, the SRB does have the jurisdiction pursuant to s. 15(5) of the *SRA* to hear objections to the issuance of a ROE. In this regard, each respondent must be notified of an application for a ROE, even if a respondent confirms that it would be unaffected by the grant of a ROE. If there is a change to those registered on title during an application for a ROE, an amended application must be filed with the SRB before the SRB can issue the ROE.[404]

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397 *Supra* note 391.
398 *Air Products*, *supra* note 396 at 2.
399 *Ibid.*
400 *Ibid.* at 4-5 [emphasis in original].
401 *Ibid.* at 5.
402 In this regard, s. 15(6) of the *SRA*, *supra* note 391, states that "where the activity the operator proposes to engage in is the subject of a licence, permit or other approval granted by," *inter alia*, the ERCB, the SRB is required to "ensure that the right of entry order is not inconsistent with the licence, permit or other approval granted." In *Access Pipeline Inc. v. Prodaniuk*, SRB Decision 2010/0126 (12 February 2010), the SRB was requested to amend a ROE to be consistent with the ERCB permit. There, while the ROE was issued in respect of a single pipeline, the ERCB permit authorized construction of two pipelines and both the landowners and operator were aware that two pipelines would be constructed. The SRB determined to amend the ROE to include both pipelines, without the need for a further hearing process, being satisfied that Access Pipeline Inc. had a valid ERCB permit for the construction of the two pipelines.
403 SRB Decision 2009/0501 (25 November 2009) [*Fort Industrial*].
404 See *Emerald Bay Energy Inc. v. Parfett*, SRB Decision 2010/0159 (25 February 2010) at 3.

In SRB proceedings related to Air Products' application for a ROE in respect of certain lands held by Fort Industrial Estates Ltd. (Fort), Fort objected to the issuance of the ROE, arguing, *inter alia*, that the Air Products' ERP was found by the ERCB to be deficient and that Fort had filed a formal review request with the ERCB to address concerns about routing and public safety.

The SRB determined that it would hold a hearing pursuant to s. 15(5) of the *SRA* to consider Air Products' application for a ROE and the objections of Fort. Despite arguments by Air Products regarding the impact to its project that would result from a delay in the processing of the ROE application (construction move-arounds, penalties, and business costs), the SRB held that it required more information regarding the status of the ERCB permit before issuing a ROE. Fort's objections "raised some uncertainties surrounding the validity and standing of the ERCB permit."[405] Further, the SRB noted that as Air Products was required to satisfy the ERCB that its ERP met application requirements before the pipeline permit would be effective, the SRB was without authority to issue a ROE until the pipeline permit was "unconditional." That is, the SRB held that "[a]n effective and valid permit is necessary for a Right of Entry Order."[406]

3. *IMPERIAL OIL RESOURCES LIMITED V. NORRIS*[407]

Section 28(4) of the *SRA* precludes the SRB, in certain circumstances, from terminating ROEs until a reclamation certificate has been issued pursuant to the *Environmental Protection and Enhancement Act*.[408] However, s. 144(3) of the *EPEA* provides certain exceptions to the need for obtaining a reclamation certificate. For example, s. 144(3) allows the SRB to terminate a ROE without a reclamation certificate where the parties to the ROE "have entered into a surface lease with respect to the [subject] land."[409] "Surface lease" is defined in the *EPEA* as "a lease, easement, licence, agreement or other instrument granted or made … under which the surface of land has been or is being held."[410]

In *Norris*, the SRB provides further guidance on its interpretation of a "surface lease" as contemplated in s. 144(3) of the *EPEA*. On 20 June 2009, Imperial Oil, as operator, requested that the SRB terminate a ROE dated 17 September 1974 on the basis that Imperial Oil had entered into a surface lease with the landowners. Though no parties other than Imperial Oil made submissions with respect to the request for termination, the SRB rejected the request. Imperial Oil had entered into a *separate* surface lease with each of the three owners (who each held a 1/3 interest in the subject lands), each bearing a different execution date. The SRB found that the "surface lease" contemplated in s. 144(3) of the *EPEA* required that all of the landowners be party to the *same* surface lease and stated that, for purposes of s. 144(3)

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405 *Fort Industrial*, *supra* note 403 at 4.
406 *Ibid.* at 5.
407 SRB Decision 2009/0476 (17 November 2009) [*Norris*]. By application dated 16 December 2009, Imperial Oil applied for a review of the decision. In *Imperial Oil Resources Limited v. Norris*, SRB Decision 2010/0307 (20 April 2010), the SRB denied the review, holding that *Norris* would not be amended.
408 R.S.A. 2000, c. E-12 [*EPEA*].
409 *Ibid.*
410 *Ibid.*, s. 134(g).

of the *EPEA*, "multiple surface leases for the same piece of land do not constitute the parties entering into a surface lease."[411]

4. *CONOCOPHILLIPS CANADA RESOURCES CORP. V. WHITELOCK*[412]

Pursuant to s. 12 of the *SRA*, the SRB may issue ROEs that result in overlapping interests being granted to different operators. Determining compensation for the overlapping ROE in such circumstances may be more difficult than in the circumstances of a new taking, as the landowner in the case of overlapping ROEs has already been compensated at least to some extent by the prior user or users.[413]

In *Whitelock*, the SRB considered the appropriate consideration payable to landowners for a ROE that would overlap with two pre-existing users of a road access. In this case, ConocoPhillips Canada Resources Corp. (ConocoPhillips) required a ROE in respect of certain lands that were already subject to two prior users, namely ARC Resources Ltd. (ARC) and True Energy Inc. The ROE for ConocoPhillips would be located entirely on, but was shorter than, the ARC road. ConocoPhillips' expert testified that the standard practice in circumstances of overlapping ROEs was that only the original user of the roadway would pay annual compensation; any second or third users would only pay an inconvenience payment to the landowner.[414] ConocoPhillips further argued that if the second or subsequent user caused additional adverse effects, compensation should be directed to the first user rather than the landowner.[415] On the basis that it, as the third user, would not cause ongoing impacts and effects, ConocoPhillips argued that it should be required to pay compensation only for first year disturbance and inconvenience, with no annual component.

The SRB awarded no compensation for loss of use or land value in respect of the ConocoPhillips' ROE, in essence holding that the landowners had already been compensated for land value at the time that the original surface lease was negotiated and that there was no further evidence of any diminution of interest. Similarly, the SRB was not persuaded that there would be an increased loss of use as the landowners did not have use of the land at the time the ConocoPhillips' ROE was granted.[416]

However, the SRB was of the view that there would be "additional nuisance, inconvenience, and noise" arising from the activities of ConocoPhillips, which were not addressed in the surface lease agreement between the landowners and the first user.[417] In this regard, an award to the landowners was warranted. The SRB rejected the arguments of ConocoPhillips and required that payment for additional adverse effect, nuisance, and inconvenience be directed to the landowner (not the first user) and that second and subsequent users should be required to pay annual compensation. The SRB was, however, clear that only the "*incremental* adverse effect, nuisance, inconvenience, and noise" were

411 *Norris*, *supra* note 407 at 3.
412 SRB Decision 2009/0258 (14 July 2009) [*Whitelock*].
413 *Ibid.* at 4.
414 *Ibid.*
415 *Ibid.* at 3.
416 *Ibid.* at 7-8.
417 *Ibid.* at 8.

compensable.[418] Additionally, the SRB awarded a one-time payment for general disturbance pursuant to s. 25(1)(f) of the *SRA* in the amount of $2,500, which in the circumstances appears to have been intended to reflect the particular facts surrounding the relationship between the operator and landowner.

An appeal of this decision was brought by the landowners, but dismissed by the Alberta Court of Queen's Bench, with an award of party and party costs in favour of ConocoPhillips, pursuant to s. 26(9)(b)(ii) of the *SRA*.[419]

5. *HAUN V. FIRST WEST PETROLEUM INC.*[420]

Section 36 of the *SRA* allows an applicant to request an order from the SRB regarding unpaid rental arrears. In *Haun*, the applicant brought nine applications against First West Petroleum Inc. for unpaid rental arrears in accordance with the provisions of the *SRA*. After the filing of these applications, the operator went into receivership. While the applicant argued that reference in s. 36 of the *SRA* to "receiver" and "receiver-manager" was intended to address an event of insolvency, which was consistent with the general purpose of the *SRA*, the SRB refused to grant a s. 36 order against the company in light of the receivership order.

In particular, the SRB noted that the receivership order stated that "no proceeding or enforcement process of any court or tribunal shall be commenced or continued against the Receiver without written consent of the Receiver or leave of the court."[421] The SRB characterized the claim for unpaid rentals as a debt claim under the receivership order and the s. 36 application as a proceeding and/or enforcement process for that debt. In the SRB's view, such process could not be commenced, or continued, in light of the receivership order. The SRB did note, however, that once the receivership concluded, the applicant could submit a new s. 36 application.[422]

E. ALBERTA COURT OF QUEEN'S BENCH AND ALBERTA COURT OF APPEAL

1. *ENBRIDGE PIPELINES (ATHABASCA) INC. V. KARPETZ*[423]

Section 25 of the *SRA* identifies factors that the SRB may consider in determining the amount of compensation payable by an operator to a landowner/occupant for a well, pipeline, facility, or access road. The SRB has routinely considered annual compensation in the context of wellsites, pipelines, and other oil and gas developments. While annual compensation for pipelines has been a longstanding and contentious issue before the SRB,

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418 *Ibid.* at 9 [emphasis in original].
419 *Whitelock v. ConocoPhillips Resources Corp.* (21 January 2010), Edmonton 0903-12508 (Alta. Q.B.).
420 SRB Decision 2009/0599 (23 December 2009) [*Haun*].
421 *Ibid.* at 4-5.
422 *Ibid.* at 5.
423 2010 ABQB 108, 22 Alta. L.R. (5th) 314 [*Karpetz*].

the SRB and the courts have consistently refused to award annual compensation in relation to ROEs for pipelines.[424]

In October 2008, however, the SRB rendered its decision in *Enbridge Pipelines (Athabasca) Inc. v. Karpetz*.[425] In that decision, the SRB rejected pattern of dealings evidence relied upon by Enbridge in making its offer of $1,900/acre for a permanent right-of-way and $950/acre for a temporary workspace, the SRB finding that there were cogent reasons for departing from such evidence.[426] The SRB also rejected the landowners' position of $1,900/acre plus annual compensation of $100/acre, finding that it would result in double compensation.[427] Therefore, the SRB decided to award annual compensation of $100/acre plus an up-front payment of $700/acre. As this award resulted in the landowners having been paid an amount by the operator greater than that awarded by the SRB, the SRB ordered that the landowners return the overpayment to Enbridge.[428]

Pursuant to s. 26 of the *SRA*, Enbridge appealed the SRB's decision to the Alberta Court of Queen's Bench. By written judgment on 11 February 2010, the Court overturned the SRB award of annual compensation.[429]

The Court held that the appropriate standard of review in respect of the issues related to rates of compensation is "reasonableness."[430] In describing the onus placed upon the appellant Enbridge, the Court stated that in order for Enbridge to succeed in the appeal, it "must establish that either the decision, on its face, was unreasonable or that the new evidence introduced on appeal has the effect of making it so."[431]

The Court addresses two main issues in its decision. Namely, "pattern of dealings" (PoD) and annual compensation. The Court affirmed that courts in Alberta have endorsed the PoD approach to compensation awards, and have directed that "the SRB should only depart from such compensation with the most cogent reasons."[432] Based on the evidence that was presented, the Court concluded that Enbridge had established a PoD and that the SRB's reasons for rejecting the pattern were "neither cogent nor valid."[433] The Court stated:

> If the SRB held that Enbridge failed to establish a PoD, then its decision was unreasonable. Evidence at the SRB and on appeal established the existence of a PoD in the affected area. On the other hand, if the SRB did find that a PoD had been established by Enbridge and rejected its application in this case, then it was unreasonable in doing so.… While a PoD approach to compensation is not perfect, the case law has

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[424] The SRB has denied requests for annual payments in respect of pipelines in several decisions, including *Karpetz*, *ibid*.; *ARC Resources Ltd. v. Robb*, SRB Decision 2010/0084 (1 February 2010); *Talisman Energy Inc. v. Fletcher*, SRB Decision 2008/0051 (26 February 2008); *ConocoPhillips Canada Resources Corp. v. Gilkyson*, SRB Decision 2010/0162 (25 February 2010).

[425] SRB Decision 2008/0362 (14 October 2008).

[426] *Ibid.* at 24.

[427] *Ibid.* at 25.

[428] *Ibid.* at 29.

[429] *Karpetz*, *supra* note 423.

[430] *Ibid.* at para. 35. The reasonableness standard is consistent with prior judicial decisions: *Imperial Oil Resources Ltd. v. 826167 Alberta Inc.*, 2007 ABCA 131, 404 A.R. 212 [*Imperial Oil*]; *Whitelock*, *supra* note 412.

[431] *Karpetz*, *ibid.* at para. 44.

[432] *Ibid.* at para. 37, citing *Imperial Oil*, *supra* note 430 at para. 21.

[433] *Karpetz*, *ibid.* at para. 55.

> established that it is the best approach available in cases such as this, which is why it should only be departed from for cogent reasons.[434]

The Court also reviewed the annual compensation award made by the SRB, finding that it too was unreasonable:

> Although the SRB's reasoning process is, for the most part, transparent, I find that it is not justifiable nor intelligible, nor does the decision fall within a range of possible outcomes given the evidence of a pattern of dealings that was before it.[435]

The Court went on to highlight the unreasonableness of the SRB's approach in determining the amount of annual compensation, stating that

> [t]he SRB had no evidence before it as to whether any of the Respondents did experience these "effects" and, if so, the value of the losses to the individual landowners. The figure of $100 was simply grabbed out of the air by the Respondents to represent these "intangible and difficult to quantify" factors and the SRB accepted it. There was no realistic or evidentiary basis for selecting that number, … there is no basis upon which the landowners should receive annual compensation
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> …
>
> Given the dearth of evidence concerning the values of the intangible and "difficult to quantify" factors the SRB accepted as being present, it is unreasonable to make an arbitrary award that so grossly exceeds the actual value of the land involved.[436]

Finally, the Court looked to the practical difficulties of awarding annual compensation:

> In my view, such an award of annual compensation reviewable every five years creates a significant and unnecessary administrative burden.… Further, a future hearing would undoubtedly be plagued with consideration of the same arbitrary, intangible and immeasurable factors as the SRB considered in this case.[437]

The Court set aside the SRB award of compensation and fixed compensation, as requested by the operator, at $1,900 for the permanent right-of-way and $950 for the temporary work space, in accordance with the PoD established by the operator, absent any annual component to compensation.

2. *BEARSPAW PETROLEUM LTD. V. ALBERTA (ENERGY AND UTILITIES BOARD)*[438]

Section 14 and Appendix 11 of ERCB *Directive 064: Requirements and Procedures for Facilities*[439] provide that H_2S emissions detected "off lease" may be defined as a major unsatisfactory inspection, resulting in a High Risk Enforcement Action pursuant to *Directive*

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434 *Ibid.*
435 *Ibid.* at para. 70.
436 *Ibid.* at paras. 64, 66, 68.
437 *Ibid.* at para. 69.
438 2009 ABCA 361, [2009] A.J. No. 1200 (QL) [*Bearspaw*].
439 ERCB, *Directive 064: Requirements and Procedures for Facilities* (Calgary: ERCB, 2005) [*Directive 064*].

019.[440] As a result of odours detected outside of Bearspaw's fenced facility area, the ERCB issued a High Risk Enforcement Action. Bearspaw disputed the enforcement action on the basis that it owned the entire parcel of land both inside and outside the fenced facility, and that the odours were therefore not "off lease." The ERCB was unconvinced by the argument, finding that Bearspaw could not be excused from the Board's requirements intended to safeguard the public and avoid placing other land users at risk of exposure to harmful substances as a result of the unique landholding.[441]

The Court of Appeal noted that "[t]he term 'off-lease' and the term 'lease' are not defined in the legislation, regulations or directives."[442] In accepting the Board's decision as reasonable, the Court acknowledged that the area outside the fenced facility was leased by Bearspaw to a farmer, that the farmer was making use of the land beyond the fence with the consent of Bearspaw, and, as a result, Bearspaw had given up the right to use those lands in connection with its operations.[443]

3. *KELLY V. ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*[444]

The issue addressed in this decision was whether certain residents were entitled to standing in respect of an ERCB application. At the time of the proceeding before the ERCB, *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*[445]created certain zones around proposed wells, including an emergency planning zone (EPZ) and a protective action zone (PAZ). The EPZ was defined as "[a] geographical area surrounding a well, pipeline, or facility containing hazardous product that requires specific emergency response planning."[446] The PAZ was defined as "[a]n area downwind of a hazardous release where outdoor pollutant concentrations may result in life-threatening or serious and possibly irreversible health effects on the public."[447]

The ERCB received objections to the drilling of two sour gas wells from residents who lived within the PAZ, but outside of the EPZ. In determining whether the residents who had filed objections had standing pursuant to s. 26(2) of the *ERCA*,[448] the ERCB determined that residence within the PAZ was insufficient on its own to establish that a person has "rights that may be directly and adversely affected by the ERCB's approval" of the application.[449] Rather, the Board held that an objecting party must own land; "reside in a setback area or notification or consultation radius as prescribed in" *Directive 056*; or reside in the calculated EPZ for the facility in order to have rights pursuant to s. 26(2) of the *ERCA*, or must otherwise demonstrate that he "has legal rights that may be directly and adversely affected by a decision" of the ERCB.[450]

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440 *Supra* note 372.
441 *Bearspaw Petroleum Limited: Complaint Respecting EUB Enforcement Actions and Allegation of Bias Against the EUB Red Deer Field Centre*, ERCB Decision 2007-090 (6 November 2007) at 10-11.
442 *Bearspaw*, *supra* note 438 at para. 7.
443 *Ibid.* at para. 8.
444 2009 ABCA 349, 464 A.R. 315 [*Kelly*].
445 ERCB, *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry* (Calgary: ERCB, 2008) [*Directive 071*].
446 *Ibid.* at 65.
447 *Ibid.* at 68.
448 *Supra* note 314.
449 *Kelly*, *supra* note 444 at para. 13.
450 *Ibid.*

In its decision issued 28 October 2009, the Alberta Court of Appeal overturned the Board's determination on standing, finding that the Board erred in its interpretation and application of s. 26(2) of the *ERCA*. The Court found that the definition of a PAZ indicated that those who live within the PAZ *may* have their rights directly and adversely affected as a result of a hazardous release, were entitled to be included in an Applicant's Participant Involvement Program under *Directive 056*, and were to be granted standing to challenge an ERCB decision.[451] The Court therefore required that the Board hear the residents' concerns respecting the sour gas wells.

The Court held that s. 26(2) of the *ERCA* does not require that a resident within the PAZ provide substantive evidence that they *will* be directly and adversely affected, but rather only requires that they provide evidence that they *may* be directly and adversely affected.[452] The residents need not provide evidence of potential negative effects as "the location of the PAZ in conjunction with the evidence of the location of the … residences was sufficient" to establish that their rights were potentially directly and adversely affected.[453] The Court noted that, upon establishing this, the onus then shifted to the proponent to prove that the residents were in fact not directly and adversely affected.[454]

In assessing the standing of the residents, the Board also stated:

> If an objecting party or review applicant does not own land or reside in a setback area or notification or consultation radius as prescribed in ERCB Directive 56, or the calculated EPZ for the facility, *the onus is on an objecting party or review applicant* to establish that he or she has legal rights that may be directly and adversely affected by a decision by the ERCB to approve an application. The impact must be specific and *the objecting party must establish that he or she may be affected in a different way or to a greater degree than members of the general public*.[455]

The Court of Appeal disagreed with this reasoning, holding that there was nothing in s. 26(2) suggesting that a finding of "directly and adversely affected" meant being "affected in a different way or to a greater degree than members of the general public."[456] Further, the Court suggested that where a person demonstrated that they have a right to consultation pursuant to *Directive 056* and *Directive 071*, that person has a legal interest that would satisfy the first branch of s. 26(2). Further, that person would also satisfy the factual branch of whether those rights may be directly and adversely affected.

Based on the Court of Appeal's ruling, the ERCB initially suspended the issuance of any new sour gas well licences. Subsequently, the Board announced that *Directive 071* was wrong in designating the PAZ as being potentially larger than the EPZ, and therefore recalibrated the modelling such that the PAZ would not extend beyond the EPZ. Amendments to both *Directive 071* and *Directive 056* removed reference to the "emergency

451 *Ibid.* at paras. 26, 35.
452 *Ibid.* at para. 37.
453 *Ibid.* at para. 39.
454 *Ibid.* at para. 44.
455 *Ibid.* at para. 13 [emphasis added by the Court].
456 *Ibid.* at para. 32.

awareness zone" or "EAZ," which was defined as the area outside the EPZ where public protection measures may be required.[457]

4. *SINCENNES V. ALBERTA (ENERGY AND UTILITIES BOARD)*[458]

This was an appeal by landowners, Sincennes and others, to the Alberta Court of Appeal from a decision of the Alberta Energy and Utilities Board (EUB), the predecessor to the ERCB. The case involved a permit issued by the NEB to construct and operate an international "merchant" power line to be built by private enterprise based on market need. This was the first opportunity for the courts to consider the unique interdelegation provisions of the *NEB Act* governing the construction and operation of international power lines. It was also the first application to come before the EUB pursuant to the international power line permitting process provided for through 1990 amendments to the *NEB Act*.[459]

Pursuant to the *NEB Act*, two alternative processes are available for the approval of international power lines. The certificate process involves the exercise of federal law only. The permit process involved both federal authority and delegated provincial authority. An applicant is entitled to elect which process it invokes and, in this case, Montana Alberta Tie Ltd. (MATL), which was proposing to build an international power line from Alberta to Montana, elected to proceed by way of the permit process.

The NEB granted the permit, which included a condition requiring that the transmission line be constructed and operated within the general corridor applied for by MATL and approved by the NEB (Condition No. 4). MATL then applied to the EUB pursuant to ss. 14 and 15 of the *Hydro and Electric Energy Act*[460] for approval to construct and operate the subject transmission line. During the EUB hearing, the Board addressed both the location/route of the transmission line as well as the public interest in having the line built. In relation to the location or route, the Board stated that it did not believe that its jurisdiction extended "to considering the relative merit of corridors beyond the preferred route as the matter of corridor selection" had already been assessed and approved by the NEB.[461]

The Alberta Court of Appeal granted leave to appeal the decision of the EUB on two grounds: (1) "[w]hether the EUB erred in its interpretation and application of the interplay of jurisdiction between the NEB and the EUB under the *National Energy Board Act*, particularly in relation to the selection of the location of an international power line"; and (2) "[w]hether the EUB erred in its interpretation and application of the public interest test, particularly in light of the 'merchant nature' of the project."[462]

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457 ERCB, Bulletin 2009-41, "Processing of Applications for Sour Oil and Gas Development in Light of the Court of Appeal Decision in the Matter of *Kelly v. Alberta (Energy Resources Conservation Board) and Grizzly Resources Ltd.*" (13 November 2009) [ERCB, Bulletin 2009-41].

458 2009 ABCA 167, 454 A.R. 121 [*Sincennes*].

459 See generally *NEB Act*, *supra* note 4, Part III.1.

460 R.S.A. 2000, c. H-16.

461 *Montana Alberta Tie Ltd.: 230-kV International Merchant Power Line — Lethbridge Alberta to Great Falls Montana*, EUB Decision 2008-006 (31 January 2008) at 12.

462 *Sincennes*, *supra* note 458 at para. 26.

The Court of Appeal held that the standard of review with respect to the jurisdiction of the NEB and the EUB under the *NEB Act* is correctness. The Court further held that "[t]he standard of review with respect to a tribunal's application of its public interest mandate is reasonableness."[463] However, to the extent "that the issue requires the determination of the test for what constitutes public interest, the standard of review is correctness."[464]

The issue in respect of the first ground of appeal was the scope of the EUB's authority to consider the location of the line once the NEB has approved the general route. The majority of the Court considered Condition No. 4 in the permit requiring that the line be constructed and operated within the general corridor and the NEB's jurisdiction to include such a condition. In this regard, the Court noted that the *National Energy Board Electricity Regulations* specifically provide that "the location of the facilities" is a matter "in respect of which terms and conditions may be included in any permit for the construction and operation of an international power line."[465] Although recognizing that there was ambiguity in the legislation, the Court held that "the possibility of alternative locations outside the corridor has been removed from the provincial designate's authority" and that a contrary interpretation would "*promote operational conflict*."[466] While the landowners argued that such an interpretation would essentially deprive them of fundamental justice, as there would be no opportunity for them to participate in a full oral hearing regarding the route of the line, the Court disagreed, focusing in part on one of the purposes and objectives of the legislative scheme: namely, to avoid duplication of process.[467]

With respect to the public interest, the landowners argued that the EUB jurisdiction was narrow and only enabled the EUB to consider "social and economic effects of the project and the effects of the project on the environment."[468] While the Court did not conclude whether "need to Albertans" was a requisite element of the public interest, the Court came to the conclusion that the test for public interest is predominantly the formulation of an opinion by a tribunal and that there are no firm criteria for determining public interest that will be appropriate in every situation.[469] The Court concluded that the EUB did not err in its consideration of the public interest. The Court was "satisfied that the EUB's assessment of public interest was made having regard to the broad range of benefits and burdens associated with the construction and operation" of the transmission line, and further, that "[t]he assessment was made after a comprehensive review of the specific social, economic and environmental effects of the proposed line, including those that are unique to a merchant line."[470]

While the majority dismissed the appeal, a dissenting judgment was rendered by Conrad J., who would have granted the appeal on the first ground. In her view, the EUB had the right and duty to consider all relevant factors in the routing of the line, just as it would for an intra-

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463 *Ibid.* at para. 29.
464 *Ibid.*
465 S.O.R./97-130, s. 6.
466 *Sincennes, supra* note 458 at para. 50 [emphasis added].
467 *Ibid.* at para. 57.
468 *Ibid.* at para. 61.
469 *Ibid.* at para. 29, citing *Memorial Gardens Association (Canada) Ltd. v. Colwood Cemetery Co.,* [1958] S.C.R. 353 at 357.
470 *Sincennes, ibid.* at para. 73.

provincial line, including alternate routes outside the general corridor approved by the NEB.[471] Such jurisdiction was not affected by Condition No. 4 or the relevant provisions of the *NEB Act*. Indeed, Conrad J. held that a determination of the public interest by the EUB would necessarily involve consideration of whether alternative corridors were feasible and would cause less impact on the public and the environment.[472]

Leave to appeal to the Supreme Court of Canada was dismissed without reasons.[473]

5. *CYMBALUK V. ALBERTA (SURFACE RIGHTS BOARD)*[474]

On 12 March 2007, landowners brought an application before the SRB pursuant to s. 30 of the *SRA* requesting, among other things, an order that would require TransAlta to monitor the amount of soil removed from their land and where that soil was stored. That application was denied by the SRB on the basis that concerns with respect to the soils management plan were outside of its jurisdiction.

Later that year, the landowners applied pursuant to s. 29(b) of the *SRA* for a review of the ROE and the compensation order, seeking compensation for the value of top soil that had been taken from their land by TransAlta in order to repair adjacent lands, rather than being stockpiled for reclamation on their own land. The SRB also dismissed that application. It was this latter decision of the Board that was the subject of the judicial review considered by the Court.

The Court held that the standard of review for a decision of the SRB in which it declined to reconsider a prior refusal to award additional compensation to landowners was reasonableness.[475] Upon finding that the SRB's decision was reasonable and that the SRB did not err in its exercise of its discretion to reconsider a refusal to award compensation, the Court disposed of the judicial review application. While this finding was sufficient to dispose of the judicial review application, the Court provided analysis on several other issues. In particular, the Court concluded that the ROE did not validate TransAlta's conduct in removing soil from the lands, and that the terms of the ROE were not broad enough to permit TransAlta to remove topsoil and use it for purposes other than restoring the landowners' land.[476] That is, the Court found that TransAlta was acting in breach of its authority under the ROE when it used the landowners' soil to restore adjacent lands. Such a right did not exist in the ROE, nor could such a right be implied from the terms of the legislation, which only provided the operator with the "right-of-entry in respect to the surface of the land … and for or incidental to any mining operation."[477]

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471 *Ibid.* at para. 125.
472 *Ibid.* at para. 80.
473 *Roy Swanson Farms Ltd. v. Alberta (Energy and Utilities Board)*, [2009] 3 S.C.R. ix.
474 2009 ABQB 263, 471 A.R. 166.
475 *Ibid.* at para. 16.
476 *Ibid.* at paras. 22, 24.
477 *Ibid.* at para. 25.

6. *GIFT LAKE MÉTIS SETTLEMENT V. MÉTIS SETTLEMENTS APPEAL TRIBUNAL (LAND ACCESS PANEL)*[478]

The Court considered an appeal by the Gift Lake Métis Settlement on the issue of whether the Métis Settlements Appeal Tribunal (MSAT) erred in its interpretation of "cumulative effect" as found in s. 118(1)(c) in the *Metis Settlements Act*.[479] The Court noted that this decision represented the first instance in which the Land Access Panel (LAP) had been requested to make an award for "loss of cultural value and for cumulative effect."[480]

As the Court of Appeal understood it, one way of describing the LAP's approach is that compensation for cumulative effects can only be rewarded if the effects "occurred or will occur during the relevant review period."[481] While the LAP indicated a willingness to consider approaches to the valuation of cumulative effects impacts, it was not able to award compensation based on generalities about impacts or the extent of one company's responsibility for the cumulative impacts. In this regard, the LAP did not award compensation for effects that were experienced during an earlier review period, as such would amount to an award of retroactive compensation.

In the circumstances, the Court of Appeal found that the decision of the LAP was entitled to deference and concluded that the standard of review was one of reasonableness. The Court was of the view that the findings of the LAP were not unreasonable. Further, the Court held that it was not unreasonable for the LAP to require evidence from the applicant of "specific cumulative effects."[482] The appeal was dismissed.

7. *BIG LOOP CATTLE CO. LTD. V. ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*[483]

On 21 September 2009, Paperny J. rendered oral reasons for decision in respect of the above noted matter. The decision addresses a relatively new provision of the *ERCA* that came into force 20 April 2007, namely s. 41(2.2), which states:

> If an applicant makes a written request for materials to the Board for the purpose of the application for leave to appeal under subsection (2), the Board shall provide the materials requested within 14 days from the date on which the written request is served on the Board.[484]

Petro-Canada Oil & Gas (Petro-Canada) applied to the ERCB for licences to drill sour gas wells and to construct associated pipelines. In February 2009, the proceedings were suspended upon disclosure of a personal relationship between an ERCB employee involved in the application and a Petro-Canada employee who also had some involvement with the

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478 2009 ABCA 143, 454 A.R. 53 [*Gift Lake*].
479 R.S.A. 2000, c. M-14.
480 *Gift Lake*, *supra* note 478 at para. 41. See *Gift Lake Métis Settlement v. Devon Canada Corporation*, MSAT Order No. 176 (12 April 2007). All MSAT decisions can be found online: MSAT <http://www.msat.gov.ab.ca/appeals/MSATDecisions.asp>.
481 *Gift Lake*, *ibid.* at para. 36 [emphasis omitted].
482 *Ibid.* at paras. 40-41.
483 2009 ABCA 301, [2009] A.J. No. 987 (QL) [*Big Loop*].
484 *Supra* note 314.

licence application. In March of 2009, the ERCB decided to continue with the Petro-Canada application on the basis that the relationship did not create a reasonable apprehension of bias. It was this decision upon which leave to appeal was sought. In order to support the leave to appeal application, an application was made for a court order requiring that the ERCB produce certain materials.

Relying on s. 41(2.2) of the *ERCA*, the appellants requested that the ERCB make certain materials available to them, including internal Board emails and correspondence between the Board and its independent legal advisor in relation to the Petro-Canada proceeding. While the Board stated that it had produced all documents that were before the panel in arriving at its conclusion in respect of the Petro-Canada application for sour gas well licences, it did not provide internal emails or other internal documents, including transcripts of interviews not before the panel, on the basis that documents not before the panel were not relevant or required to be produced. The Board further refused to produce a legal opinion that the Board had received on the basis of solicitor-client privilege. When the appellants did not get all materials requested, they appealed.

The Court noted that the purpose of s. 41(2.2) of the *ERCA* was to provide a mechanism for an appellant who is seeking leave to request materials before the Court grants its leave.[485] While the Court refused to determine the scope of production required pursuant to s. 41(2.2) and in particular whether the statute conferred the right to documents beyond the record or supplementary to the record, the Court did determine that produceability pursuant to s. 41(2.2) is "directly related to relevance on that application" for leave.[486] The Court held that all materials relied upon by the panel were produced. The remaining documents were not before the panel, and there was a question as to their relevance. They were not "reasonably necessary" to address the leave application.[487] The Court therefore dismissed the appeal.

8. *CANADIAN NATURAL RESOURCES LTD. V. BENNETT & BENNETT HOLDINGS LTD.*[488]

On 30 March 2010, a three member panel of the Alberta Court of Appeal (Côté, Picard, and O'Brien JJ.) dismissed an appeal by Canadian Natural Resources Ltd. (CNRL) that arose, initially, from a decision of the SRB.

As background, CNRL had 11 surface leases with Bennett & Bennett Holdings Ltd. and Circle B Holdings Ltd. (collectively, Bennett). Each surface lease required that CNRL pay annual compensation. The rate of annual compensation was reviewable every five years. CNRL attempted to negotiate new compensation rates for seven of the leases when they came up for review, but the parties were unsuccessful in reaching a consensus. The matter was heard by the SRB. Before the SRB, CNRL requested that the rate of compensation be reduced. However, the SRB increased the rate of compensation. CNRL appealed the SRB decision to the Alberta Court of Queen's Bench. Pursuant to s. 26(6) of the *SRA*, the appeal to the Court of Queen's Bench was in the form of a new hearing — or trial *de novo*.

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485 *Big Loop, supra* note 483 at para. 6.
486 *Ibid.* at para. 9.
487 *Ibid.*
488 2010 ABCA 91, 477 A.R. 226 [*Bennett*].

While the Court allowed the appeal in part, CNRL sought leave to appeal the decision to the Alberta Court of Appeal. CNRL raised four grounds of appeal. The Court granted leave on only two grounds: namely, whether the judge misconstrued the test for determining whether a pattern of dealings existed and erred in considering factors not in issue at the hearing, and whether the judge erred in rejecting the expert testimony of whether a "pattern of dealings" existed.[489]

CNRL argued that the chambers judge erred in their determination that no pattern of dealings had been established, as well as the way in that the Court reached that conclusion. In particular, CNRL argued that several of the factors that the Court considered in concluding that no pattern of dealings had been established were not relevant and that a pattern of dealings could be determined without reference to such factors.[490]

In dismissing the CNRL appeal, the Court concluded that the chambers judge did not decide unreasonably. The Court of Appeal did not consider that the lower court's consideration of the above noted factors were preconditions to a determination of whether a pattern of dealings exists, although they noted that even if those factors were firm rules, the result of their decision would not have been different.[491] Further, the Court of Appeal noted certain deficiencies in the expert's evidence, notably that the expert lacked defined selection criteria and confined his review to only certain comparables made by one or two companies, and the comparables relied upon were a considerable distance from the wellsite locations at issue, with no evident rationale for not using closer comparables.[492]

9. *FREEHOLD PETROLEUM AND NATURAL GAS OWNERS ASSOCIATION V. ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*[493]

Section 28 of the *ERCA* defines "local intervener" for the purposes of awarding costs to those who participate in an ERCB hearing. A local intervener includes a person with an interest in land whose interest "may be directly and adversely affected by a decision of the Board."[494]

In February 2009, the ERCB convened a hearing to consider an application by Montane for a review pursuant to s. 39 of the *ERCA* of an OMERS well licence. Prior to the hearing, the ERCB granted to the Freehold Petroleum and Natural Gas Owners Association (the Association) full participation rights. However, the Board did note that the Association was allowed to participate regardless of whether it had standing and that the Association's participation did not bear on its status as a local intervener or its entitlement to local intervener costs. Ultimately, the ERCB denied recovery of costs to the Association.[495] The Association sought leave to appeal on two grounds, one of which was whether the Board

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489 *Ibid.* at para. 3.

490 *Ibid.* at para. 6. For a listing of the factors considered, see *Canadian Natural Resources Ltd. v. Bennett & Bennett Holdings Ltd.*, 2008 ABQB 19, 436 A.R. 256 at para. 88, citing *Intensity Resources Ltd. v. Dobish* (1989), 94 A.R. 366 (Q.B.).

491 *Bennett*, *ibid.* at para. 8.

492 *Ibid.* at paras. 19-24.

493 2010 ABCA 125, [2010] A.J. No. 405 (QL) [*Freehold*].

494 *Supra* note 314.

495 *Freehold*, *supra* note 493 at paras. 3-7.

erred in determining that rights of a member of the Association would not be affected by a decision of the Board.

The Court of Appeal dismissed the leave to appeal application on the basis that the grounds of appeal did not warrant the grant of leave. The Court deferred to the Board's determination of whether the requirements of s. 28 of the *ERCA* had been met, namely whether the Association's members had an interest in land that may be directly and adversely affected by the decision of the Board.[496] This case is interesting for the apparent basis upon which the Association was permitted to participate fully in the hearing. In this regard, the related ERCB Cost Order cites correspondence from the Board dated 6 February 2009 whereby the Board stated that although the Association "may not satisfy the criteria as set out in section 26(2) of the ERCA to attain standing at the hearing … the [Association] and its members may have extensive and perhaps unique experience on the principal issues arising in this proceeding."[497]

10. *TRANSCANADA PIPELINE VENTURES LTD. V. ALBERTA (UTILITIES COMMISSION)*[498]

TransCanada Pipeline Ventures Ltd. (Ventures) owns and operates the natural gas Ventures Pipeline. In 1998, Suncor and Ventures entered into a long-term agreement for gas transmission services.

In March 2006, Suncor applied to the EUB requesting that the Board investigate the services and tolls of Ventures Pipeline. The issue was whether the Ventures Pipeline was a "gas utility" pursuant to the *GUA*[499] and whether the Board had the jurisdiction to investigate, and regulate, the rates and services of the pipeline. The Board determined that it had the jurisdiction to conduct an investigation. This decision was upheld on appeal.[500]

As a result of the investigation, the AUC — the successor of the EUB in these matters — determined that the rates on the Ventures Pipeline were "unjust or unreasonable, unjustly discriminatory, or unduly preferential" and determined that it would regulate the pipeline.[501] TransCanada sought leave to appeal to the Alberta Court of Appeal, arguing that the AUC did not have the jurisdiction to interfere with private contracts, or rates that were set pursuant to those contracts, where the contract only related to the provision of services and does not involve the provision or supply of gas or a commodity. The Court of Appeal disagreed.

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496 *Ibid.* at para. 12.

497 *OMERS Energy Inc.: Section 39 Review of Well Licences No. 036235 and No. 0392996 — Warwick Field*, ERCB Cost Order 2009-008 (11 August 2009) at 4.

498 2010 ABCA 96, 474 A.R. 350 [*TransCanada Ventures*].

499 *Supra* note 210.

500 *Suncor Energy Inc.: Preliminary Decision Regarding Jurisdiction to have the Ventures Pipeline (Oil Sands Pipeline) Regulated Under the Provisions of the* Gas Utilities Act, EUB Decision 2006-105 (24 October 2006), aff'd *TransCanada Pipeline Ventures Ltd. v. Alberta (Energy and Utilities Board)*, 2008 ABCA 55, 429 A.R. 171.

501 *TransCanada Pipeline Ventures Ltd. & Suncor Energy Inc.: Application to Have the Ventures Pipeline (Oil Sands Pipeline) Regulated Under the Provisions of the* Gas Utilities Act — *Section 24 of the* Gas Utilities Act — *Investigation*, AUC Decision 2009-065 (20 May 2009) at 26.

In considering the AUC's powers under its governing legislation, the Court of Appeal noted that s. 17 of the *GUA*, with respect to contracts for the supply of gas, provides the Commission "with broad procedural and substantive powers."[502] Further, s. 36 of the *GUA* also grants the Commission broad rate-making and ancillary powers that are complementary to, and supportive of, the powers conferred in s. 17, and are sufficiently broad to grant the Commission the power to adjust contractual rates.[503] Finally, the Court noted that s. 25(a) of the *GUA* also supported their conclusions by limiting the rates the owner of a gas utility may impose. As a result, the Court held that "[a]n excessive charge made under a contract is no less objectionable than one made where no formal and express contract exists."[504]

Therefore, relying on the statutory provisions of the *GUA*, the Court concluded that the Commission had the jurisdiction to set rates for transmission service provided by Ventures Pipeline. The Court also relied on a public policy argument to support the position that the Commission has the ability to change contractual rates. The Court reasoned that to allow gas utilities "to escape regulation merely by entering into contracts with members of the public … would be contrary to the public interest mandate entrusted to the Commission."[505] The Court was reluctant to construe the legislation in a manner that would defeat the Commission's mandate when other reasonable interpretations of the legislation were available.[506]

The Court held that even if its interpretation of the *GUA* was incorrect, s. 81 of the *Public Utilities Act*[507] would fill "a gap in the jurisdiction," as it allows the Commission to adjust rates for the supply of a commodity or service.[508]

11. *HUNT OIL COMPANY OF CANADA V. GALLEON ENERGY*[509]

This judicial decision originated from an ERCB proceeding held in respect of an application by Hunt Oil Company of Canada (Hunt) to amend its enhanced recovery scheme in order to drill additional wells. Galleon Energy Ltd. (Galleon), who had a competing waterflood operation, objected to the application and was granted standing by the ERCB. While the ERCB ultimately approved Hunt's application, it decided to hold a hearing to consider the application.

Subsequent to the Board's approval of the Hunt application, Hunt sued Galleon in tort seeking damages of $30 million, alleging that Galleon's objection in the ERCB process was both improper and prolonged the approval process. While the main issue before the Court was whether the statement of claim should be struck, the decision of the Alberta Court of Queen's Bench confirms that, in the circumstances, the claims in the statement of claim "undermine the administrative law process and are an abuse of the process of this Court."[510]

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502 *TransCanada Ventures*, *supra* note 498 at para. 39.
503 *Ibid.* at para. 41.
504 *Ibid.* at para. 43.
505 *Ibid.* at para. 46.
506 *Ibid.*
507 R.S.A. 2000, c. P-45.
508 *TransCanada Ventures*, *supra* note 498 at para. 53.
509 2010 ABQB 212, [2010] A.J. No. 348 (QL).
510 *Ibid.* at para. 83.

Further, the Court held that the potential for litigation subsequent to the ERCB process "could only detract from parties appropriately participating in the ERCB process."[511] The Court struck the statement of claim, finding that it disclosed no cause of action and was an abuse of process of the Court.

12. ATCO GAS AND PIPELINES LTD. AND THE ALBERTA UTILITIES COMMISSION

During the past 12 months, the Alberta Court of Appeal has rendered three decisions related to the assets of a regulated utility, ATCO Gas and Pipelines Ltd. (ATCO). In particular the Court dealt with issues relating to the sale of ATCO's Harvest Hills property; the change in use of its Salt Caverns; and the effective date for removal of the Carbon facility (a natural gas storage facility) from rate base. ATCO was successful on appeal in all cases.

In *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board),*[512] the Court dealt with issues arising from the sale of ATCO's Harvest Hills property. Following direction previously provided by the Supreme Court of Canada and the Alberta Court of Appeal, the Alberta Court of Appeal affirmed that the AUC has no jurisdiction to appropriate proceeds from the sale of lands that are neither used nor required to be used to provide service to customers.[513] Further, the AUC has no jurisdiction to impose a condition on, or appropriate proceeds from, the sale of property where the property never had a utility use. Moreover, the Court held, in a separate decision,[514] that changing the use of, or ceasing to use, an asset for utility purposes is not subject to the approval of the AUC pursuant to s. 26 of the *GUA*.[515] The Court did indicate that the AUC retained jurisdiction to require that a utility demonstrate that it was prudent to remove those assets from service as part of its normal prudence review at the next rate case.

In the third decision, the Court of Appeal dismissed an application by the City of Calgary that requested leave to appeal a decision of the AUC.[516] The AUC decision dealt with the issue of the appropriate adjustment date for assets that are sold or disposed of by the utility. The issue related to the disposition of the Carbon facility, a natural gas storage asset and, in particular, the appropriate adjustment date for the purposes of adjusting rate base and revenue requirement. While the City argued that the relevant adjustment date was the date upon which the AUC granted approval for the sale pursuant to s. 26 of the *GUA*, the AUC determined that the relevant adjustment date was the date upon which the AUC rendered its decision deciding that the Carbon facility was neither being used by ATCO nor required to be used for providing regulated utility service. The Court denied the City's leave to appeal application on the basis that the appellants had not raised "a serious arguable question of law or jurisdiction."[517] In essence, the Court held that upon the AUC determining that the Carbon facility was neither being used by ATCO nor required to be used for providing regulated

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511 *Ibid.* at para. 82.
512 2009 ABCA 171, 454 A.R. 176.
513 *Ibid.* at para. 29, citing *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board),* 2006 SCC 4, [2006] 1 S.C.R. 140; *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board),* 2008 ABCA 200, 433 A.R. 183.
514 *ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission),* 2009 ABCA 246, 464 A.R. 275.
515 *Ibid.* at para. 56.
516 *Calgary (City of) v. Alberta (Utilities Commission),* 2010 ABCA 158, [2010] A.J. No. 540 (QL).
517 *Ibid.* at para. 20.

utility service, the AUC had no jurisdiction to include that asset in rate base. It is this date that represented the appropriate adjustment date.

F. CANADA-NEWFOUNDLAND AND LABRADOR OFFSHORE PETROLEUM BOARD AND THE CANADA-NOVA SCOTIA OFFSHORE PETROLEUM BOARD

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) was created in 1985 under the Atlantic Accord and has regulatory oversight of operator activity for the purposes of regulating the oil and gas industry offshore Newfoundland and Labrador and on behalf of the Governments of Canada and Newfoundland and Labrador. The C-NLOPB regulates three production facilities offshore Newfoundland and Labrador: Hibernia, Terra Nova, and White Rose. Pursuant to its enabling legislation,[518] the four regulatory mandates of the C-NLOPB are: safety, environmental protection, resource management, and industrial benefits.

Established in 1990 under the authority of the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*,[519] the Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB) regulates petroleum activities and resources offshore Nova Scotia.

1. OFFSHORE HELICOPTER SAFETY INQUIRIES

On 8 April 2009, the C-NLOPB announced that it would establish an inquiry into worker safety following a tragic helicopter crash offshore Newfoundland and Labrador on 12 March 2009.[520] The offshore helicopter safety inquiry was established to make recommendations regarding safety plan requirements for companies operating in the offshore area and the roles that these companies play to ensure that safety plans are maintained by helicopter operators; search and rescue obligations of helicopter operators required by contract or legislative or regulatory requirements; and the role of the C-NLOPB and other regulators to ensure companies comply with legislative requirements for worker safety. The Commissioner of the Inquiry, Robert Wells, is to receive expert reports by 31 May 2010. A public comment process and hearing process commencing 28 June 2010 will follow.

2. *HIBERNIA DEVELOPMENT PLAN AMENDMENT APPLICATION*[521]

By Decision Report 2009.10, the C-NLOPB approved the *Hibernia Development Plan Amendment Application*, which was submitted by Hibernia Management and Development Company Ltd. (HMDC) on 5 June 2009. The HMDC recently released the *Hibernia Development Plan Amendment — Part I*[522] and the *Amendment to the Hibernia Benefits Plan*

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518 See the *Canada-Newfoundland Atlantic Accord Implementation Act*, S.C. 1987, c. 3 [*Newfoundland Accord Act*]; *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*, R.S.N.L. 1990, c. C-2.

519 S.C. 1988, c. 28 [*Nova Scotia Accord Act*].

520 C-NLOPB, News Release, "C-NLOPB Announces Inquiry Into Worker Safety Associated With Helicopter Crash" (8 April 2009), online: C-NLOPB <http://www.cnlopb.nl.ca/news/nr20090408eng.shtml>.

521 *Hibernia Development Plan Amendment Application*, C-NLOPB Decision Report 2009.10 (7 August 2009), online: C-NLOPB <http://www.cnlopb.nl.ca/index.shtml>.

522 HMDC, *Hibernia Development Plan Amendment — Part I* (St. John's: HMDC, 2010).

— *Hibernia Southern Extension Project*.[523] and is accepting comments from the public until 31 May 2010.

G. ONTARIO ENERGY BOARD

The OEB regulates the province's natural gas and electricity sectors in the public interest. The following discussion highlights developments from the OEB for the period May 2009 to April 2010.

1. OEB DECISION ON A PRELIMINARY MOTION EB-2009-0172: *ENBRIDGE GAS DISTRIBUTION INC.*[524]

An application by Enbridge sought to recover in rates costs associated with certain green energy initiatives. Without determining whether it had the jurisdiction to include such costs in rate base, the OEB declined to allow such investments citing both general utility principles and policy. According to the OEB, "[w]hen assets are allowed in rate base it is generally because those assets are related to the monopoly franchise."[525] In the circumstances, Enbridge did "not have a monopoly franchise for the production of renewable energy."[526] Further, from a policy perspective, allowing a public utility to include such costs in rate base would transfer the risk to the ratepayer, which in the Board's view would be "unfair to other market participants."[527] Allowing such costs would also be inconsistent with government policy under the *Electricity Act, 1998*,[528] which requires that funding for renewable energy projects "come from all electricity ratepayers, not only the ratepayers of the utility that decides to embark on those initiatives."[529] Having regard to the scheme of legislation, the OEB concluded that "there is no compelling reason to conclude that the costs of renewable energy projects should be allowed in the rate base of a gas utility."[530] Therefore, none of the costs were to be borne by Enbridge's ratepayers through their natural gas rates.

2. OEB DECISION EB-2009-0422 — OEB APPROVAL OF APPLICATION BY DAWN GATEWAY PIPELINE LIMITED PARTNERSHIP GRANTING LEAVE TO CONSTRUCT A NATURAL GAS PIPELINE

On 23 December 2009, Dawn Gateway filed an application for leave to construct an approximately 17 km natural gas pipeline. In a prior decision of the Board, which dealt with Union Gas' application to sell its St. Clair Line to Dawn Gateway to be integrated into a new cross-border service from Michigan to Ontario, the OEB determined that it had jurisdiction over the proposed 17 km pipeline.[531] As a result of that decision, Dawn Gateway withdrew its application from the NEB that had requested approval pursuant to s. 58 of the *NEB Act*

523 HMDC, *Amendment to the Hibernia Benefits Plan — Hibernia Southern Extension Project* (St. John's: HMDC, 2010).
524 *Enbridge Gas Distribution Inc.*, OEB Decision on a Preliminary Motion EB-2009-0172 (22 December 2009) [*Enbridge I*].
525 *Ibid.* at 5.
526 *Ibid.*
527 *Ibid.* at 6.
528 S.O. 1998, c. 15, Sch. A.
529 *Enbridge I*, *supra* note 524 at 8.
530 *Ibid.*
531 See *Union Gas*, *supra* note 53.

for the construction of the same facilities as well as purchase of the two existing lines which would have connected physically to the international border. In *Dawn Gateway*,[532] the OEB granted leave to construct the 17 km of pipeline.

Dawn Gateway also sought approval for a "regulatory framework," which included a proposal to charge tolls at negotiated rates; an approach that was based on the practice of the NEB related to Group 2 companies. In particular, Dawn Gateway sought to have its tolls and tariffs regulated on a complaints basis and to file its annual audited financial statements. Parties questioned whether the NEB's normal practice for Group 2 companies is to require that tolls be filed. The OEB stated:

> The Board does not intend to determine whether each and every price in each and every contract is just and reasonable. Rather, the Board is being asked to approve maximum rates. The Board concludes that it is not necessary for the Board to see each rate in each contract and to make a determination that they are just and reasonable. Rather, the Board is relying on a complaint system just as the NEB does. Nor does the NEB make an Order relating to each rate in each contract.[533]

This decision is a significant development in terms of the enhanced flexibility afforded pipeline developers in Ontario to implement market-based rates.

3. UPDATE ON MULTI-YEAR INCENTIVE REGULATION FOR NATURAL GAS UTILITIES

In July 2008, the OEB issued its decision in relation to a multi-year incentive rate-setting methodology for Enbridge Gas Distribution Inc. (Enbridge Gas Distribution) and Union Gas Limited (Union Gas).[534] The OEB has advised that it considers that this approach to rate-making has been "positive," citing the efficiency benefits passed on to consumers in 2008 — with Union Gas sharing excess earnings of $34.5 million and Enbridge Gas Distribution sharing excess earnings of $5.8 million with customers.[535]

4. UPDATE ON NATURAL GAS FORUM

In the fall of 2003, the OEB undertook a comprehensive sector review aimed at improving the efficiency and effectiveness of natural gas regulation in the province, releasing *Natural Gas Regulation in Ontario: A Renewed Policy Framework*.[536] The conclusions and recommendations achieved through the reporting framework were designed for implementation over several years through a series of public processes inclusive of stakeholder participation.

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532 *Supra* note 53.
533 *Ibid.* at para. 47.
534 *Enbridge Gas Distribution Inc., Union Gas Ltd.*, OEB Joint Decisions EB-2007-0606 & EB-2007-0615 (31 July 2008).
535 See Pamela Nowina, "LDC Gas Forum in conjunction with Industrial Gas Users Association" (Speech by OEB Vice-Chair, Montreal, 13 November 2009), online: OEB <http://www.oeb.gov.on.ca/OEB/_Documents/Speeches/speech_IGUA_Nowina_20091113.pdf>.
536 OEB, *Natural Gas Regulation in Ontario: A Renewed Policy Framework* (30 March 2005), online: OEB <http://www.oeb.gov.on.ca/documents/consultation_ontariogasmarket_report_300305.pdf> [*Policy Framework*].

Numerous recommendations arose as a result of the *Policy Framework* and as a result, the Board has been continually working to address several identified key issues. In this regard, the following summarizes recent noteworthy developments arising in response to issues identified by the *Policy Framework*.

a. Pre-Approval of Cost Consequences — Long-Term Supply

Arising from a Board initiated consultation process to discuss the needs, benefits, and risks of entering into long-term contracts for natural gas supply, including the potential impact of these contracts on competition, utilities will be given the opportunity (that is, it is not mandatory) to apply on a case-by-case basis for pre-approval of long-term contracts that support the development of new natural gas infrastructure. Guidelines govern the pre-approval process.[537]

b. Commodity Pricing, Load Balancing, and Cost Allocation of Regulated Supply

In September 2009, the Board issued a decision on methodologies for gas commodity pricing, load balancing, and cost allocation between supply and delivery functions.[538] The Board determined that the 12-month forecast period and quarterly rate adjustment frequency in place was appropriate and rejected a proposed Ontario wide reference commodity price. The 12-month rolling approach to disposing of account balances was upheld. While identical filing requirements were not mandated on utilities, some standardization measures were implemented. The harmonization of load balancing policies was rejected. Instead, a series of changes to the establishment of mean daily volume and daily contract quantity were proposed and are scheduled to take effect in 2011. The Board also addressed the need for regulated gas supplies to be structured and provided for in a format facilitative of competition. While the OEB determined that the incremental costing approach for setting the gas supply administration fee (currently utilized) was appropriate, it rejected the implementation of a standardized billing terminology between utilities.[539]

c. Storage and Transportation Access Rule (STAR)

Following a determination that the OEB would not regulate the prices charged for storage services offered by Enbridge, Union Gas, and affiliated operators, the Board released a rule in December 2009, slated to come into force 16 June 2010, to address affiliate relationships through operating and reporting requirements, and a complaint process.[540] Rules regarding non-discriminatory access to transportation services establish operating requirements and

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[537] Letter from Kirsten Walli, Secretary, OEB to all participants in EB-2008-0280, "Filing Guidelines for the Pre-Approval of Long-Term Natural Gas Supply and/or Upstream Transportation Contracts" (23 April 2009).

[538] *Methodologies for Commodity Pricing, Load Balancing and Cost Allocation for Natural Gas Distributors*, OEB Decision EB-2008-0106 (21 September 2009) [*Methodologies*]. The OEB issued this amended decision and order following an additional proceeding, launched on a Board motion pursuant to ss. 19 and 36 of the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch. B.

[539] *Methodologies*, *ibid.* at 32-35.

[540] Letter from Kirsten Walli, Secretary, OEB to all participants in Consultation Process EB-2008-0052 (Phase I of STAR) & all other interested parties, "Notice of Issuance of a New Rule: Storage and Transportation Access Rule (STAR)" (9 December 2009).

reporting requirements for natural gas transmitters, integrated utilities, and storage companies.

d. Distribution Revenue Decoupling (EB-2010-0060)

On 22 March 2010, the Board initiated a consultation process to examine revenue adjustment and cost recovery mechanisms available to distributors in an effort to address revenue erosion resulting from unforecasted changes in energy volumes sold. "Revenue decoupling" fully or partially disconnects the link between consumption and revenue. Pacific Economics Group Research was retained to analyze available mechanisms and issued a report titled *Review of Distribution Revenue Decoupling Mechanisms*.[541] The Board has invited comments on the report until 3 May 2010. Following stakeholder meetings, the OEB will render final recommendations and policies.

H. ENVIRONMENTAL APPEALS BOARD

1. APPEAL NOS. 07-010-021-R: *STONE AND ULFSTEN V. DIRECTOR, NORTHERN REGION, REGIONAL SERVICES, ALBERTA ENVIRONMENT, RE: IMPERIAL OIL RESOURCES LIMITED, ENCANA CORPORATION, CANADIAN NATURAL RESOURCES LIMITED, HUSKY OIL OPERATIONS LIMITED, AND BLACKROCK VENTURES INC.* (*NOW SHELL CANADA LTD.*)[542]

"Alberta Environment, through its airshed policies, is developing a province wide program to monitor air quality on a regional basis in addition to a facility-based approach."[543] As part of the move towards regional airshed monitoring, Alberta Environment issued several amending approvals under the *EPEA* for six existing enhanced recovery in situ oil sands or heavy oil processing facilities near Cold Lake, Alberta, operated by Imperial Oil, EnCana, CNRL, Husky Oil Operations Limited, and Shell Canada Ltd. (collectively, the approval holders). The amending approvals incorporated the Lakeland Industry and Community Association (LICA) Air Quality Monitoring Program Network to monitor air quality in the area.

The issuance of the amending approvals was appealed by a number of area residents and groups, many of which were either withdrawn or dismissed by the Environmental Appeals Board (EAB) ultimately leaving two area residents as the appellants. The main issues on appeal were the adequacy of the LICA Air Quality Monitoring Program Network with respect to the monitoring of ambient air quality in relation to health and environmental safety and whether the monitoring program was "properly designed having regard to the potential

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541 Mark Newton Lowry & Matt Makos, *Review of Distribution Revenue Decoupling Mechanisms* (Madison, Wisc.: Pacific Economics Group Research, 2010), online: OEB <http://www.oeb.gov.on.ca/OEB/_Documents/EB-2010-0060/Report_Revenue_Decoupling_20100322.pdf>.

542 *Stone and Ulfsten v. Director, Northern Region, Regional Services, Alberta Environment, re: Imperial Oil Resources Limited, EnCana Corporation, Canadian Natural Resources Limited, Husky Oil Operations Limited, and Blackrock Ventures Inc.* (*now Shell Canada Ltd.*), EAB Appeal Nos. 07-010-021-R (27 May 2009), online: EAB <http://www.eab.gov.ab.ca/>.

543 *Ibid.* at para. 177.

for facility upset conditions."[544] Other issues were whether LICA had an adequate quality assurance program and employed properly qualified personnel.[545]

The LICA monitoring program included three stationary continuous monitors, one portable continuous monitoring station, and 25 passive monitors, compared with the previous monitoring system of 78 static monitors, ten passive monitors, and eight continuous monitors that operated at various intervals throughout the year.[546] The EAB recognized that although there were fewer monitors under the LICA system, the information collected by passive and continuous monitors would "be more useful for measuring and analyzing regional emissions."[547] As well, the continuous monitors would be more effective as they would "be spread throughout the airshed instead of being located in proximity to one facility."[548] The appellants were not necessarily opposed to regional monitoring, but wanted, in addition to regional monitoring, all of the monitoring requirements in place before the issuance of the amending approvals.[549]

The Board recognized that the purpose of the amending approvals was to give effect to a mandated requirement on the part of the approval holders to participate collectively in a regional air monitoring system managed by an outside agency (that is, LICA). The facility-specific monitoring conditions and stack emission monitoring conditions in each of the approval holders' approvals did not change as a result of the issuance of the amending approvals.[550] The Board accepted that the move towards regional airshed monitoring was "a sound approach to assessing cumulative impacts of development in a specific area."[551] Although the appellants expressed concerns with this approach, "the Board had no evidence presented to it to recommend changes to the Alberta Environment airshed monitoring policy and program."[552]

With respect to facility upset conditions, the Board clarified that "the primary intent of regional airshed monitoring is not to catch exceedances" but "to measure cumulative impacts of the various facilities on the air quality in a specific airshed."[553] Compliance monitoring still applied to all of the approval holders, as conditions still existed in the original approvals "to record and measure stack emissions and upsets."[554]

With respect to the other issues, the Board found that LICA's program to ensure quality and employ qualified personnel was acceptable.[555]

Ultimately, the Board stated that there was "value in the policy shift from site specific 'fence line' monitoring to regional airshed monitoring networks."[556] However, the Board

544 *Ibid.* at para. 14.
545 *Ibid.*
546 *Ibid.* at para. 183.
547 *Ibid.* at para. 185.
548 *Ibid.*
549 *Ibid.* at para. 201.
550 *Ibid.* at para. 200.
551 *Ibid.*
552 *Ibid.*
553 *Ibid.* at para. 204.
554 *Ibid.* at para. 206.
555 *Ibid.* at paras. 207-21.
556 *Ibid.* at para. 222.

made a number of recommendations "to improve residents' confidence in LICA's operations and the transparency of the monitoring program."[557]

III. LEGISLATIVE DEVELOPMENTS

Significant legislative developments have occurred in the period from May 2009 to April 2010 in jurisdictions across Canada. The following is a summary of relevant federal legislative developments and statutory developments arising in the Canadian provinces of Alberta, British Columbia, Saskatchewan, and Ontario that are of relevance to energy practitioners.

A. FEDERAL

The federal government released the details of its 2010 budget on 4 March 2010.[558] The budget incorporates several key regulatory and environmental initiatives of significance, including an initiative to streamline regulatory regimes, which would focus on streamlining the northern regulatory review and modernizing the regulatory system for project review. With respect to the latter, and what appears to be a response to difficulties in dealing with environmental assessments, approvals, and First Nation consultation, the budget proposes that environmental assessments for energy projects be delegated from the CEA Agency to the NEB and the Canadian Nuclear Safety Commission (CNSC) for those projects that fall respectively within each agency's area of expertise.[559]

Following the release of *Budget 2010*, proposed changes were announced to the *CEAA* pursuant to Bill C-9: *An Act to implement certain provisions of the budget tabled in Parliament on March 4, 2010 and other measures*.[560] For example, a new s. 15.1(1) in the *CEAA* would allow the Environment Minister to determine the scope of a project as being limited to one or more components,[561] and a new s. 7.1(2) would identify certain classes of projects — generally federally funded infrastructure projects — for which no environmental assessment would be required. Environment Minister Jim Prentice has stated that the proposed changes will ensure that "we get good environmental outcomes" while "not delaying and frustrating projects through unnecessary red tape."[562]

Proposed amendments to s. 11.01 of the *CEAA* would recognize that the CNSC or the NEB could be the "responsible authority" with respect to an environmental assessment process.[563] The NEB has recently posted to its website information regarding its new role

557 *Ibid.*

558 Department of Finance, *Budget 2010: Leading the Way on Jobs and Growth* (Ottawa: Public Works and Government Services Canada, 2010), online: Department of Finance <http://www.budget.gc.ca/2010/pdf/budget-planbudgetaire-eng.pdf> [*Budget 2010*].

559 *Ibid.* at 104.

560 3d Sess., 40th Parl., 2010 (as passed by the House of Commons 8 June 2010) [Bill C-9]. The provisions of the *CEAA* are required to be reviewed every five years. The next review was to have commenced in May 2010.

561 This latter provision is in response to the Supreme Court of Canada decision in *MiningWatch Canada v. Canada (Fisheries and Oceans)*, 2010 SCC 2, [2010] 1 S.C.R. 6.

562 Martin Mittelstaedt & Gloria Galloway, "Ottawa revises rules of environmental review regime" *The Globe and Mail* (31 March 2010), online: The Globe and Mail <http://www.theglobeandmail.com/news/politics/ottawa-revises-rules-of-environmental-review-regime/article1518844/>.

563 Bill C-9, *supra* note 560.

under the *CEAA*, confirming that it would now be responsible for completing environmental assessments for projects within its jurisdiction that would otherwise have been assessed by a joint review panel under the *CEAA*. Under the contemplated "substituted process,"[564] a joint funding program similar to that currently found in the *CEAA* would be established to provide support for meaningful participation of the public in the regulatory process.

1. THE *CANADA OIL AND GAS DRILLING AND PRODUCTION REGULATIONS*, *NEWFOUNDLAND OFFSHORE PETROLEUM DRILLING AND PRODUCTION REGULATIONS*, AND *NOVA SCOTIA OFFSHORE PETROLEUM DRILLING AND PRODUCTION REGULATIONS*

The *Canada Oil and Gas Drilling and Production Regulations*[565] were brought into force on 31 December 2009 and are an amalgamation and modernization of the *Canada Oil and Gas Drilling Regulations*[566] and the *Canada Oil and Gas Production and Conservation Regulations*[567] that formerly existed under *COGOA*[568] and the *Newfoundland Accord Act* and *Nova Scotia Accord Act*. The new regulations are intended to improve the regulatory framework[569] and to address issues regarding duplication and the prescriptive nature of the regulations,[570] which have historically led to increased costs, inefficiency, and ineffectiveness.[571] The changes are intended to support continued growth and competitiveness in the frontier and the offshore oil and gas industry, "while maintaining the highest standards for safety, environmental protection and management of resources."[572] The NEB, together with the C-NSOPB and C-NLOPB, is in the process of developing goal-oriented guidelines that will supplement the *Production Regulations*.

Both the current and past regulations are mostly directed towards technical requirements and operations respecting safety, appropriate conservation of hydrocarbon resources, and the protection of the environment during drilling and production operations,[573] and having a management system in place to ensure compliance.[574] In addition to identifying reporting requirements, the regulations set out the information that must accompany regulatory applications.[575]

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564 NEB, "Participant Funding and Substitution of Environmental Assessments," online: NEB <http://www.neb.gc.ca/clf-nsi/rsftyndthnvrnmnt/nvrnmnt/nvrnmnt-eng.html>. The "substituted process" has always been available under the *CEAA*, and was invoked as a pilot project in 2006 in respect of the Emera Brunswick Pipeline Project. On 2 October 2009, the CEA Agency issued its report on the project substituted hearing.

565 S.O.R./2009-315 [*Production Regulations*]. Consequential amendments to the *Canada Oil and Gas Installations Regulations*, S.O.R./96-118, and the *Canada Oil and Gas Certificate of Fitness Regulations*, S.O.R./96-114 also came into force on 31 December 2009.

566 S.O.R./79-82, as rep. by *Production Regulations*, *ibid.*

567 S.O.R./90-791, as rep. by *Production Regulations*, *ibid.*

568 *Supra* note 8.

569 For example, the regulations improve flexibility for the development of regulatory process efficiencies by permitting the Board to address certain matters (that is, well spacing) by way of Orders: Registration SOR/2009-315, C. Gaz. 2009.II.2306 at 2342.

570 *Ibid.* at 2344. The regulations are more goal-oriented and incorporate goal-based and performance-based elements, although prescriptive elements remain in respect of management systems and information reporting requirements (at 2339). In particular, standards are no longer incorporated into the regulations; rather, operators are expected to identify the "appropriate standards, codes and practices to be applied for specific projects and for their use in achieving compliance" (at 2341-42).

571 *Ibid.* at 2338.

572 *Ibid.* at 2338-39.

573 *Ibid.* at 2339.

574 *Ibid.* at 2340.

575 *Ibid.* at 2339.

In conjunction with the *Production Regulations* coming into force, the NEB, C-NLOPB, and C-NSOPB also released the *Draft Safety Plan Guideline: Guidance for the Development of a Safety Plan for Work or Activities*,[576] which will be available on a one-year trial basis. The Board has invited comments on the *Draft Safety Plan Guidelines* until 31 December 2010.[577] While the *Draft Safety Plan Guidelines* are not mandatory, they are goal-oriented and intended to assist operators in understanding the *Production Regulations* and developing a safety plan as required pursuant to s. 6 thereof.

2. THE *TRANSPORTATION OF DANGEROUS GOODS ACT, 1992*[578]

Amendments in 2009 to the *TDGA* provide that a person will be deemed an "importer" if that person is named in the "shipping record accompanying dangerous goods or a means of containment on entry into Canada as the person in Canada to whom" delivery is to occur.[579] Further, amendments to ss. 3(2) and (4) are intended to reconfirm that the *Act* applies throughout Canada to the transport of dangerous goods, even if that movement is intra-provincial and does not involve a federally-regulated shipper, unless otherwise exempted from the application of the *Act*.[580]

B. ALBERTA

Several significant enactments have come into force during the period May 2009 to April 2010 that affect, or have the potential to affect, the rights and obligations of parties engaged in oil and gas activities in Alberta.

1. BILL 12: *SURFACE RIGHTS AMENDMENT ACT, 2009*[581]

The *SRAA* came into force on 9 December 2009 and amends the *SRA*. Substantive changes were implemented to streamline the regulatory process and increase efficiency and have the potential to reduce costs for all parties involved. The amendments impact the powers of SRB members,[582] remove time requirements imposed on the SRB for issuing decisions, and substitute the term "proceeding" in place of "hearing" in several sections of the *SRA*.[583]

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576 NEB, C-NLOPB & C-NSOPB, *Draft Safety Plan Guideline: Guidance for the Development of a Safety Plan for Work or Activities* (31 December 2009), online: NEB <http://www.neb-one.gc.ca/clf-nsi/rpblctn/ctsndrgltn/rgltnsndgdlnsprsnttthrct/drllngprdctnrgltn/sftplngdlndrft20091231-eng.pdf> [*Draft Safety Plan Guidelines*].

577 The Board notes that it would anticipate releasing additional draft guidance for consultation purposes within the first half of 2010.

578 S.C. 1992, c. 34, as am. by S.C. 2009, c. 9, s. 2 [*TDGA*].

579 *Ibid.*, s. 2.1.

580 David Johansen, "Bill C-9: An Act to Amend the Transportation of Dangerous Goods Act, 1992," Legislative Summary LS-631E (Ottawa: Library of Parliament, 2009), online: Parliament of Canada <http://www2.parl.gc.ca/Content/LOP/LegislativeSummaries/40/2/c9-e.pdf>.

581 2d Sess., 27th Leg., Alberta, 2009 (assented to 4 June 2009), S.A. 2009, c. C-2.5 [*SRAA*].

582 *SRA*, *supra* note 391, s. 8.

583 For example, the SRB now has the power to enter on and inspect any buildings, works, or property, or conduct an examination of any real or personal property in connection with a *proceeding*, whereas previously it could do so only in connection with a *hearing*. Those sections of the *SRA*, *ibid.*, in which the word "proceeding" arises are ss. 8, 10-11, 23-24, 26-27, 30-31, 35, and 39.

The Chair of the SRB is now permitted to select a single member of the SRB to address any matter and to grant that member the full powers and jurisdiction of the SRB.[584] Further, the SRB is authorized to conduct proceedings through written submissions[585] rather than oral hearings and is authorized to utilize alternative measures for dispute resolution, such as meetings, mediation, or other dispute resolution processes such as dispute resolution conferences.[586] Any settlement reached by the parties in those processes can be adopted by the SRB as its decision.[587]

2. THE *CARBON CAPTURE AND STORAGE FUNDING ACT*[588]

The *CCSFA* was enacted "to encourage and expedite the design, construction and operation of carbon capture and storage projects in Alberta" in pursuit of the government's objective to reduce greenhouse gases.[589] The *Act* commits up to $2 billion from the General Revenue Fund towards carbon capture and storage projects,[590] with the allocation of funds to be determined by the Minister of Energy generally through grants or contracts for service.[591] The *Act* provides the Lieutenant-Governor with the ability to make regulations setting out the requirements and conditions of grant agreements or contracts for service, or with respect to any other circumstances, the manner in which a payment may be made under the *Act*.[592] This legislation is a key component in providing tools for Alberta to become a world leader in carbon capture and storage technology.

3. THE *ALBERTA LAND STEWARDSHIP ACT*[593]

The writers of this article understand that an article published herein will address the details of this legislation and its potential implications for project proponents.[594] Indeed, while the *Act* is not directed solely at the oil and gas industry, it may have significant implications for how proponents design and implement a project, and has the potential to affect the validity of existing approvals a proponent may hold.

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584 *Ibid.*, s. 3(6).
585 *Ibid.*, s. 8(3.1).
586 *Ibid.*, s. 8(2)(e). See also SRB, News Release, "Streamlined Surface Rights Board improves dispute resolution process — Landowners, operators welcome mediated meeting format" (9 December 2009), online: SRB <http://www.surfacerights.gov.ab.ca/Content_Files/Files/NewsRelease.pdf>; SRB, *Surface Rights Board Dispute Resolution Process* (N.P.), online: SRB <http://www.surfacerights.gov.ab.ca/Content_Files/Files/SRBDisputeResolutionProcess.doc>.
587 *SRA*, *ibid.*, s. 8(3.2).
588 S.A. 2009, c. C-2.5 [*CCSFA*].
589 *Ibid.*, s. 1.
590 Government of Alberta, "Carbon Capture and Storage," online: Alberta Energy <http://www.energy.alberta.ca/Initiatives/1438.asp>. As a result of this legislation, the $2 billion committed to the fund has been allocated to four steel-in-ground Carbon Capture Storage projects: (1) TransAlta Corporation Project Pioneer ($436 million); (2) Shell Quest Project ($745 million); (3) Enhance Energy Inc. and North West Upgrading's Alberta Carbon Trunk Line ($495 million); and (4) Swan Hills Synfuels ($285 million).
591 *CCSFA*, *supra* note 588, ss. 2-3.
592 *Ibid.*, s. 5.
593 S.A. 2009, c. A-26.8.
594 Alan Harvie & Trent Mercier, "The *Alberta Land Stewardship Act* and its Impact on Alberta's Oil and Gas Industry" (2010) 48 Alta. L. Rev. 295.

4. THE *ENERGY STATUTES AMENDMENT ACT, 2009*[595]

The *ESAA* was enacted to achieve the goals of clean energy production, wise energy use, and sustained economic prosperity set out in the provincial energy strategy,[596] while eliminating inefficiencies found in existing energy legislation. The effect of the *ESAA* is to repeal the *Natural Gas Price Administration Act* and the *Natural Gas Pricing Agreement Act* and to amend ten energy-related statutes. While identified by the legislature as being a "housekeeping" Act, there are several substantive amendments to existing energy statutes.[597]

Pursuant to amendments to the *OGCA*, the "Orphan Fund" has been expanded to include "large facilities," defined as a central processing facility or an upgrader integrated into a central processing facility with capacity of 5000 m^3 or more per day; a stand-alone straddle plant; and a gas processing plant with sulphur recovery and a sulphur inlet of one tonne or more per day.[598] Working interest participants of large facilities are responsible for paying to the licensee the proportionate share of an orphan fund levy prescribed by the ERCB.[599] As well, the amendments allow the ERCB, upon receiving a written request from the licensee of a large facility or a working interest participant of a large facility with a 50 percent or greater share, to order proportional payment by each working interest participant of a security deposit imposed on the licensee.[600]

Further, the ERCB may now deem a transferor of a large facility as a continuing licensee of a facility[601] or can deem a licensee of a large facility to be a defaulting licensee where it fails to meet an obligation to contribute to suspension, abandonment, or reclamation costs and where the licensee "does not exist, cannot be located or does not have the financial means to contribute."[602]

In addition, the ERCB is now entitled, for the five years following enactment, to prescribe orphan fund levies against non-producer licensees of oilfield waste management facilities.[603] The levy must be sufficient to cover the suspension, abandonment, and reclamation costs, and any reimbursement costs associated with the orphan oilfield waste management facility.[604] However, the total amount levied must not exceed $2 million.[605]

The prior requirements for obtaining approval or authorization from the Lieutenant-Governor has been removed with respect to permits for the use of energy resources as raw material or fuel; declarations regarding common carriers, common purchasers, and common

595 S.A. 2009, c. 20 [*ESAA*].
596 Alberta Energy, *Launching Alberta's Energy Future: Provincial Energy Strategy* (Edmonton: Alberta Energy, 2008) at 21, online: Alberta Energy <http://www.energy.alberta.ca/Org/pdfs/AB_ProvincialEnergyStrategy.pdf>.
597 Legislative Assembly, *Alberta Hansard*, Issue 43e (25 May 2009) at 1246-47.
598 *OGCA*, *supra* note 249, s. 1(1)(aa.1).
599 *Ibid.*, s. 74(1.1).
600 *Ibid.*, s. 26.1.
601 *Ibid.*, s. 31.1. This would occur where the transferee, within 24 months of the transfer, becomes bankrupt or insolvent, inactive, dissolved, or is struck from the corporate registry, and the Board finds that the transfer has resulted in suspension, abandonment, and reclamation costs being transferred without corresponding value in assets being transferred.
602 *Ibid.*, s. 70(2)(b.1).
603 *Ibid.*, s. 76.1(1).
604 *Ibid.*, s. 76.1(2).
605 *Ibid.*, s. 76.1(4).

processors; orders regarding a drilling spacing unit as being operated as a unit pursuant to a specific formation; and termination of an order varying a pooling order.[606]

Other amendments implemented pursuant to the *ESAA* include changes to the *Petroleum Marketing Act*.[607] *Hansard* suggests that these changes lay the foundation for the bitumen royalty in kind program.[608] The amendments reflect that the Petroleum Marketing Commission (PMC) is now responsible for receiving and dealing with, on behalf of the Crown, the royalties owed by lessees related to "hydrocarbon substances," as opposed to those just related to crude oil.[609] As such, the PMC may receive delivery of hydrocarbon substances or money from the lessee as payment of the Crown royalty.[610]

One other amendment of note was made to the *ERCA* whereby the ERCB may, upon the failure of an operator to pay an administration fee as prescribed by s. 27.2 of the *ERCA*, "shut in a facility, oil sands project, coal project or well of an operator."[611]

5. THE *REMEDIATION CERTIFICATE REGULATION*[612]

Pursuant to s. 112 of the *EPEA*, where a substance is released into the environment that has caused or has the potential to cause an adverse effect, the person responsible for the release is obligated to undertake remedial measures.[613]

The *RCR*, enacted on 3 June 2009, sets out the information to be included in a remediation certificate application[614] and identifies when the Director may exercise its discretion to issue a remediation certificate.[615] The Director is required to provide a notice of refusal to accept the application or refusal to issue a remediation certificate or, where approved, a copy of the remediation certificate issued to both the applicant and landowner.[616]

The *RCR* also specifies that an Environmental Protection Order can be issued after a remediation certificate is granted if an inspector or the Director finds that: (1) a substance specified in the remediation certificate remains present in the remediated zone at a level in excess of that permitted at the time the certificate was issued, or (2) a person caused a change in the condition or use of the remediated area such that the substance has or may cause an adverse effect.[617]

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606 *ESAA*, *supra* note 595, ss. 7(6)-(14). Similar amendments have also been made to the *Oil Sands Conservation Act*, R.S.A. 2000, c. O-7.
607 R.S.A. 2000, c. P-10 [*PMA*].
608 Legislative Assembly, *Alberta Hansard*, No. 43e (25 May 2009) at 1246 (Dr. Kevin Taft).
609 *PMA*, *supra* note 607, s. 15.
610 *Ibid.* ss. 15, 18, 19(2)(a).
611 *Supra* note 314, s. 27.2(5).
612 Alta. Reg. 154/2009 [*RCR*].
613 *Supra* note 408.
614 *Supra* note 612, s. 3(2). The information to be included in the application consists of maps and details indicating, among other things, the location and boundaries of the remediated area, depth of the remediation, the substance released and its depth and concentration on the land, the location of water bodies or wells within 300 m of the remediated area, the location of all buildings on the remediated or adjacent areas, site investigation reports, a detailed history of each release of the substance, written details on the remediation procedure and the results of the remediation, and plans to monitor and mitigate or prevent adverse effects outside of the remediated zone.
615 *Ibid.*, s. 4.
616 *Ibid.*, s. 6.
617 *Ibid.*, ss. 8(2)-(3).

6. BILL 50: *ELECTRIC STATUTES AMENDMENT ACT, 2009*[618]

On 1 June 2009, the Government of Alberta introduced the *Electric Statutes Amendment Act, 2009*, which changes the *Electric Utilities Act*.[619] The *Act* introduces the concept of "critical transmission infrastructure" (CTI) with respect to the regulation of electric transmission facilities in the province. CTI is defined in the *Act* as "a transmission facility designated under section 41.1 or the Schedule as critical transmission infrastructure."[620] In this regard, s. 41.1(1) of the *EUA* provides that the Lieutenant-Governor in Council may designate as critical transmission infrastructure a proposed transmission facility that meets certain criteria.[621] Further, the referenced schedule to the *EUA* describes certain transmission infrastructure as "critical transmission infrastructure." To date, five proposed infrastructure projects have been designated as CTI projects.

Designating facilities as CTI removes the "needs identification document" requirement and determination from AUC approval.[622] That is, while the facility approval will still be within the jurisdiction of the AUC, it will now be the Alberta government rather than the AUC that will determine the need for such facilities. In its decisions regarding siting of CTI, the AUC must consider the public interest. Amendments were also made to the *Transmission Regulation*[623] respecting the determination of eligibility to construct and operate critical transmission facilities.

C. BRITISH COLUMBIA

1. THE *GREENHOUSE GAS REDUCTION (CAP AND TRADE) ACT*[624]

The *GGRA* and the associated *Reporting Regulation*[625] impose the requirement for gas emissions reporting as of November 2009 for operators of a "regulated operation or reporting operation."[626] The *Reporting Regulation* sets out the requirements for meeting the emission reporting obligations established by the *Act* and identifies the criteria for determining whether an operation is a regulated or reporting operation.

The *Reporting Regulation* requires an operator to meet reporting requirements if the operation is a single facility or linear facilities operation that "has a total amount of attributable greenhouse gas emissions that is greater than or equal to [10,000] metric tonnes of carbon dioxide equivalent."[627] A greenhouse gas emission is "attributable" if an operation involves a specific activity, source, and gas type as identified in Schedule A of the *Reporting*

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618 2d Sess., 27th Leg., Alberta, 2009 (assented to 26 November 2009), S.A. 2009, c. 44.
619 S.A. 2003, c. E-5.1 [*EUA*].
620 *Ibid.*, s. 1(1)(f.1)
621 *Ibid.*
622 *Lavesta Area Group: Written Complaint about the Conduct of the Independent System Operator*, AUC Decision 2010-104 (10 March 2010) at 17-18 [*Lavesta*]. In *Lavesta*, the Commission held that the issue was whether the Alberta Electric System Operator had breached s. 34(1) of the *EUA* by not filing a needs identification document in respect of certain transmission infrastructure. *Lavesta* was rendered moot by the *Electric Statutes Amendment Act, 2009*, *supra* note 618.
623 Alta. Reg. 86/2007.
624 S.B.C. 2008, c. 32 [*GGRA*].
625 B.C. Reg. 272/2009.
626 *GGRA*, *supra* note 624, s. 4.
627 *Supra* note 625, s. 6.

Regulation, such as hydrogen production, stationary combustion at oil and gas facilities, petroleum refining, natural gas storage and processing, oil and gas extraction and processing, or oil and natural gas transmission.[628] The information to be included in an emissions report is set out in s. 12 of the *Reporting Regulation*,[629] although additional information may be required in specific circumstances.[630]

The operator subject to reporting requirements must meet its reporting obligation on an annual basis, commencing on 1 January 2010 or on the date thereafter that the operations commence.[631] Provisions with respect to compliance reporting appear to be forthcoming.[632]

D. SASKATCHEWAN

1. *THE PIPELINES ACT, 1998*[633]

On 14 May 2009, amendments to *The Pipelines Act, 1998* came into force, broadening the definition of "pipeline" to include a system of pipes used for the transportation of carbon dioxide.[634]

E. ONTARIO

1. THE *GREEN ENERGY ACT, 2009*[635]

On 14 May 2009, the *GEA* received royal assent. The intent of the *GEA* is to boost investment in renewable energy projects and increase conservation. While the renewable energy projects are focused on electricity generation, the *Act* marks a significant shift in the focus of the Ontario energy market to creating a green economy. The *Act* also transfers the cost burden for connection of renewable energy generation facilities from the proponent to Ontario ratepayers, which has been the subject of controversy.

As part of the *GEA*, the Feed-in Tariff Program (the FIT Program) was initiated, which allows proponents to apply to the Ontario Power Authority for a power purchase contract (the FIT Contract). The FIT Contract sets the price for producing renewable energy (which varies depending on the renewable source). Currently, the price represents a significant increase over the average hourly price for electricity set by the Ontario Independent Electric System Operator, thereby giving parties incentive to enter into the Ontario renewable generation market.

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628 *Ibid.*, s. 2. See generally Sch. A.
629 *Ibid.*, s. 12.
630 *Ibid.* A verification statement from an independent body may be required which confirms there are no material errors, omissions, or misrepresentations in the report. It should be noted that a verification statement from a body that is not independent of the operator may still be accepted where the verification body establishes and documents strategies for mitigating any threat to its independence (s. 22(2)).
631 *Ibid.*, s. 8.
632 *GGRA*, *supra* note 624, s. 3.
633 S.S. 1998, c. P-12.1.
634 *Ibid.*, s. 2(j)(i)(D).
635 S.O. 2009, c. 12, Sch. A [*GEA*].

As a result of the introduction of the *GEA* and development of the FIT Program, the role of the OEB has also shifted from assessing matters in terms of economic efficiency to creating a green economy. The OEB's objectives have been amended accordingly to reflect this shift.[636]

IV. DEVELOPMENTS IN POLICY, DIRECTIVES, AND GUIDELINES

The following discusses relevant developments in policy, directives, and guidelines arising from the federal NEB, the ERCB, and the SRB.

A. NATIONAL ENERGY BOARD

1. AMENDMENTS TO THE *NATIONAL ENERGY BOARD RULES OF PRACTICE AND PROCEDURE, 1995*

On 31 August 2009, the NEB notified interested parties that it was considering amending and updating the *National Energy Board Rules of Practice and Procedure, 1995*[637] to reflect current practice, include technological updates, address recurring procedural issues, and clarify terminology.[638] The preliminary draft of the proposed *NEB Rules* was provided to interested parties and the Board requested comments be provided by 16 November 2009.[639] Amendments are proposed to NEB requirements for service, filings, participation, evidence in written and oral proceedings, witnesses, reply evidence and argument, reviews and rehearings, and stays.

2. REVISIONS TO THE NEB FILING MANUAL AND RESCISSION OF THE BOARD'S 6 DECEMBER 1995 MEMORANDUM OF GUIDANCE

By letter dated 17 November 2009, the NEB rescinded the Board's 6 December 1995 Memorandum of Guidance regarding the regulation of Group 2 companies.[640] The letter provides guidance and clarifies the financial regulatory requirements for both Group 1 and Group 2 companies, which are now outlined in Guide P of the NEB *Filing Manual*[641] and reminds parties about the requirements under s. 74 of the *NEB Act* for the transfer, sale,

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636 On 21 September 2009, the OEB announced that two initiatives related to the *GEA* had been completed. In particular, the Distribution System Code was amended to ensure timely connection of renewable energy. Further, payment procedures for generation facilities under the FIT Program were simplified: OEB, News Release, "Ontario Energy Board code amendments facilitate connecting renewable generation" (21 September 2009), online: OEB <http://www.oeb.gov.on.ca/OEB/_Documents/Press%20Releases/news_release_DSC-RSC_20090921.pdf>.

637 *Supra* note 32.

638 Letter from Anne-Marie Erickson, Acting Secretary, NEB to all interested parties, "Amendments to *National Energy Board Rules of Practice and Procedure, 1995* ("Rules") — Request for Comments" (31 August 2009).

639 NEB, *National Energy Board Rules of Practice and Procedure, 20XX, National Energy Board Act*, Draft (Calgary: NEB, 2009) [*NEB Rules*]. After 16 November 2009, the Board's draft amended rules will be published in the Canada Gazette and the public will again have an opportunity to provide comments.

640 Letter from Anne-Marie Erickson, Acting Secretary, NEB to all pipeline companies under the jurisdiction of the *NEB Act* and interested parties, "Financial Regulation of Pipeline Companies under the Board's Jurisdiction" (17 November 2009).

641 NEB, *Filing Manual* (Calgary: NEB Publications Office, 2004), online: NEB <http://www.neb-one.gc.ca/clf-nsi/rpblctn/ctsndrgltn/flngmnl/flngmnl-eng.pdf>.

purchase, lease, or abandonment of a pipeline or the amalgamation of a company with any other company.[642]

Guide P has also been revised to reflect the NEB's guidance provided in its 17 November 2009 letter noted above, including the addition of information regarding the distinction between Group 1 and Group 2 companies. Two new sections have also been added to Guide P. In P.6, the distinction between Group 1 and Group 2 companies is clarified. This section also sets out the tolls and tariffs filing requirements for Group 2 companies. P.7 addresses abandonment cost obligations, in accordance with the Board's RH-2-2008 decision. Further, Guide BB.1 was added to the *Filing Manual*, confirming that although Group 2 companies remain exempt from the *Toll Information Regulations*,[643] the NEB may still perform audits of the company.[644]

3. PROPOSED REGULATORY CHANGE PRC 2010-01 — ADOPTION OF *CSA Z246.1-09 SECURITY MANAGEMENT FOR PETROLEUM AND NATURAL GAS INDUSTRY SYSTEMS*[645]

In April 2005, "security" was added to the mandate of the NEB through amendments to the *NEB Act*, authorizing the NEB to regulate the security of energy infrastructure under its jurisdiction. Although this broader mandate of the Board was implemented through amendments to the *Onshore Pipeline Regulations, 1999* and the *National Energy Board Processing Plant Regulations*,[646] the NEB also advised companies subject to NEB regulation of the Board's expectations for companies to have an established security management program.[647]

In August 2009, a new CSA standard *CSA Z246.1-09: Security Management for Petroleum and Natural Gas Industry Systems*[648] was published. By letter dated 26 November 2009, the Board announced that it was considering replacing the existing PRC 2006-01 with PRC 2010-01 in order to require that companies have in place a security management program in compliance with *CSA Z246.1-09*.[649] Following receipt of comments, the Board advised that it would adopt *CSA Z246.1-09* into the regulations. PRC 2010-01 would be in effect as of 1 April 2011.[650] The Board also advised that until regulations come into force, the new PRC would be the basis for the Board's interim expectations and regulatory compliance activities for pipeline security and associated programs.

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642 *Supra* note 4.

643 S.O.R./79-319.

644 See NEB, "Filing Manual Revisions — Guide P — Tolls and Tariffs (Part IV of NEB Act) and Guide BB — Financial Surveillance Reports (*Toll Information Regulations*)," online: NEB <http://www.neb-one.gc.ca/clf-nsi/rpblctn/ctsndrgltn/flngmnl/ntc2009_11_17-eng.html>.

645 NEB, "Proposed Regulatory Change PRC 2010-01 — Adoption of *CSA Z246.1-09 Security Management for Petroleum and Natural Gas Industry Systems*" (3 May 2010) [PRC 2010-01].

646 S.O.R./2003-39.

647 NEB, "Proposed Regulatory Change 2006-01 — Pipeline Security Management Programs" (24 May 2006) [PRC 2006-01].

648 CSA, *CSA Z246.1-09: Security Management for Petroleum and Natural Gas Industry Systems* (Mississauga: CSA, 2009) [*CSA Z246.1-09*].

649 Letter from Anne-Marie Erickson, Acting Secretary, NEB to all oil and gas companies under the jurisdiction of the NEB and interested parties, "Notice of Proposed Regulatory Change 2009-01 — Adoption of *CSA Z246.1-09: Security Management for the Petroleum and Natural Gas Industry*" (26 November 2009).

650 PRC 2010-01, *supra* note 645 at 1.

4. NORTHERN DRILLING POLICY — SAME SEASON RELIEF WELL CAPABILITY

On 5 February 2010, the Board announced that it would hold a written hearing to review its policy on same season relief well (SSRW) capability for oil and gas drilling operations in the Beaufort Sea.[651] SSRW capability refers to the ability to drill a relief well in the same season in which the original well was drilled. These activities are regulated under *COGOA* and are intended to assist in controlling a blowout and reduce impact of a hydrocarbon release into the Arctic Ocean. Prior to the announcement regarding review of the SSRW policy, the Board had denied an October 2009 application by Imperial Oil requesting an advance ruling on SSRW.[652]

As part of the hearing process, the Board was proposing to hold a technical conference and would receive submissions on the factors that the Board should consider in determining the content and applicability of its SSRW capability policy, an issue which the Board has called "of significant public concern."[653] However, on 20 April 2010, a tragic accident in the Gulf of Mexico involving the sinking of the drilling rig *Deepwater Horizon* caused the Board to re-evaluate the proceeding. Following receipt of solicited comments, the NEB announced the cancellation of the SSRW hearing process on 11 May 2010 and the commencement of a review of Arctic safety and environmental offshore drilling requirements.[654] The news release noted that there was no offshore drilling in Canada's Arctic at the time and that no applications for drilling were before the NEB.

5. NEB RELEASES REPORT REGARDING THE 9 JULY 2006 RUPTURES OF THE PINE RIVER GAS PLANT SULPHUR PIPELINE

On 9 July 2006, ruptures on the Pine River Gas Plant Sulphur Pipeline resulted in the pipeline being shut down, which caused the solidification of liquid sulphur in the pipeline. During the re-melt, the liquid sulphur expanded and hydraulic shock occurred, which increased internal pressures and ruptured the pipeline as stress was greater than the material tensile strength.

By letter dated 8 July 2009, the Board advised that it had completed its investigation into the ruptures of the pipeline pursuant to s. 12(1.1) of the *NEB Act* and was issuing an order to Spectra. Further, in accordance with its authority pursuant to ss. 12(1.1) and 48(1.1) of the *Act*,[655] the NEB also issued a report regarding the ruptures, including findings as to the cause and contributing factors, and two decisions relating to the prevention of future similar

651 NEB, News Release, 10/03, "National Energy Board to Review Northern Drilling Policy" (5 February 2010), online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/nwsrls/2010/nwsrls03-eng.html> [NEB, "Northern Policy"].

652 Letter from Anne-Marie Erickson, Acting Secretary, NEB to James Hawkins, Arctic Operations Manager, Imperial Oil, "Application to the National Energy Board for Advance Ruling on Policy for Same Season Relief Well (SSRW) Capability in the Beaufort Sea" (19 November 2009).

653 NEB, "Northern Policy," *supra* note 651.

654 NEB, News Release, 10/12, "National Energy Board Announces Review of Arctic Safety and Environmental Offshore Drilling Requirements" (11 May 2010), online: NEB <http://www.neb-one.gc.ca/clf-nsi/rthnb/nwsrls/2010/nwsrls12-eng.html>.

655 *Supra* note 4. Section 48(1.1) authorizes the Board to order that a company "take measures that the Board considers necessary for the safety and security of a pipeline."

accidents.[656] These two decisions required the submission to the Board of a report assessing the adequacy of surge protection installations and availability of emergency power for black-start generators, and a proposed plan for ongoing periodic assessments of the pipeline's integrity and identifying root causes of abnormal operating condition events and their effects.[657]

While the report is related specifically to the Pine River occurrence, the Board advises that

> [a]ll companies should review the findings and corrective actions and make appropriate changes to their management systems and operations to avoid similar future accidents. Specifically, companies should note the findings and decisions with respect to the adequacy of surge protection installations and the availability of emergency power for operations of critical systems.[658]

6. FINANCIAL REGULATORY AUDIT POLICY

The Board updated its Financial Regulatory Audit Policy on 22 February 2010.[659]

7. AMENDMENT TO THE *NATIONAL ENERGY BOARD COST RECOVERY REGULATIONS*[660]

Each year, the Board recovers certain of its operating and other costs from the companies that it regulates. As of 1 January 2010, amendments to the *Cost Recovery Regulations* came into force, requiring that costs currently recovered from electricity exports be recovered from NEB-regulated power line companies. In essence, the Board will now impose a levy on owners and operators of transmission facilities based on (1) the annual amount of energy that the company transmits (exports and imports), and (2) a one-time levy for new entrants calculated at 0.2 percent of the capital costs incurred for construction of new facilities to reflect the regulatory process required to consider the facilities applications. The purpose of the amendments is to ensure an equitable attribution of costs in recognition of the current industry structure and, in particular, to reflect that the transmission function has been separated from other functions.

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656 NEB, *Investigation under the* National Energy Board Act *In the Matter of: 9 July 2006 ruptures of the Pine River Gas Plant Sulphur Pipeline, owned and operated by Westcoast Energy Inc. carrying on business as Spectra Energy Transmission* (Calgary: NEB Publications Office, 2009).

657 *Ibid.* at Appendix IX.

658 Letter from Claudine Dutil-Berry, Secretary, NEB to all oil and gas companies under the jurisdiction of the NEB and all interested parties, "Investigation under the *National Energy Board Act* In the Matter of: 9 July 2006 ruptures of the Pine River Gas Plant Sulphur Pipeline, owned and operated by Westcoast Energy Inc. carrying on business as Spectra Energy Transmission" (8 July 2009).

659 See attachment to letter from Anne-Marie Erickson, Acting Secretary, NEB to all pipeline companies under the jurisdiction of the NEB, "Financial Regulatory Audit Policy" (22 February 2010).

660 S.O.R./91-7 [*Cost Recovery Regulations*].

B. ENERGY RESOURCES CONSERVATION BOARD

1. *DIRECTIVE 075: OILFIELD WASTE LIABILITY (OWL) PROGRAM*[661]

Directive 075 was issued on 15 September 2009. It implements the OWL Program, a liability management program governing oilfield waste management facilities, and applies to all ERCB-approved waste management (WM) facilities, other than those dedicated to landfill purposes.[662]

The objective of the OWL Program is to prevent the costs of suspending, abandoning, remediating, and reclaiming an ERCB-approved oilfield WM facility from being incurred by Albertans where a licensee becomes defunct and to minimize the risk to the Orphan Fund arising from facilities, wells, and pipelines with unfunded liability.[663] *Directive 075* sets out detailed information with respect to the types of facilities, wells, and pipelines that will be subject to the OWL Program and Orphan Fund; the licence and approval transfer process under the OWL Program; the formula for determining the liability management rating (LMR) for nonproducer and producer licensees; and the requirements for calculation of deemed assets and liabilities.[664]

A licensee's LMR assessment is determined by a comparison of a licensee's deemed assets and deemed liabilities in the OWL, Licensee Liability Rating (LLR), and Large Facility Liability Management program. A security deposit may be required if the licencee's deemed liabilities in these programs exceed its deemed assets. The deposit is meant to minimize the possibility that the Orphan Fund will need to bear costs of a licensee's suspension, abandonment, remediation, and reclamation costs.[665] That is, if a licensee becomes defunct, the deposit can be utilized to cover costs. If the security deposit does not cover such costs, the Orphan Fund is used.[666]

Each licensee is also required to pay a levy to the Orphan Fund, which reflects a percentage of the total Orphan Fund levy calculated for all licencees in the LLR and OWL programs.[667] Regardless of an LMR assessment, the OWL Program requires each nonproducer licensee or eligible producer licensee to provide a facility-specific security deposit for the amount by which a WM facility's liabilities exceed its deemed assets, which is refundable once the facility has 12 months of throughput, its deemed assets equal or exceed its liabilities, and it is compliant with the requirements of the ERCB.[668]

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661 ERCB, *Directive 075: Oilfield Waste Liability (OWL) Program* (Calgary: ERCB, 2009) [*Directive 075*].
662 *Ibid.* at 2.
663 *Ibid.*
664 *Ibid.* at 8-15, Appendices 1-5.
665 *Ibid.* at 3.
666 *Ibid.*
667 *Ibid.* at 5.
668 *Ibid.* at 4.

2. *DIRECTIVE 076: OPERATOR DECLARATION REGARDING MEASUREMENT AND REPORTING REQUIREMENTS*[669]

Directive 076, which came into effect on 16 December 2009, "sets out new requirements according to which operators are to declare the degree to which they have infrastructure in place to ensure compliance with ERCB measurement and reporting requirements."[670] It applies to all operators subject to the ERCB and Petroleum Registry of Alberta (PRA) measurement and reporting requirements, and to conventional oil, heavy oil, crude bitumen, and natural gas facilities.[671]

To ensure compliance with the measurement and reporting requirements, *Directive 076* implements the ERCB's Enhanced Production Audit Program, which is designed to reduce the ERCB's reliance on substantive audits by increasing the effectiveness of every operator's evaluation controls.[672] While operators have discretion in terms of the controls to be implemented, the *ERCB Enhanced Production Audit Program: EPAP Operator's Handbook*[673] provides guidance, and the ERCB may direct an operator to implement changes to improve the design or operation of controls or evaluation processes.[674]

Operators must conduct an annual evaluation of controls, provide the ERCB with a reasonable level of assurance that they are in fact conducting adequate evaluations,[675] and submit annual declarations attesting to the state of the controls.[676] The first declaration must be submitted within two years of the effective date of *Directive 076* or within two years of its first submission to the PRA, whichever is later.[677] For declarations made within the first year of such dates, "noncompliance with any requirement in [the] directive will not be subject to … enforcement."[678] Otherwise, control deficiencies or noncompliance with the measurement and reporting requirements may, for example, require the submission of a reasonable remediation plan.[679]

3. *DIRECTIVE 056: ENERGY DEVELOPMENT APPLICATIONS AND SCHEDULES*[680]

Directive 056 is an ever changing guideline, continually being adapted to provide further clarification to project proponents with respect to the requirements for project applications. Amendments in 2009 introduced a process for pipeline applications that use fiberspar or

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669 ERCB, *Directive 076: Operator Declaration Regarding Measurement and Reporting Requirements* (Calgary: ERCB, 2009) [*Directive 076*].
670 *Ibid.* at 1.
671 *Ibid.*
672 *Ibid.* at 2.
673 ERCB, *ERCB Enhanced Production Audit Program: EPAP Operator's Handbook* (Calgary: ERCB, 2010).
674 *Directive 076, supra* note 669 at 2.
675 *Ibid.* at 4.
676 *Ibid.* at 3.
677 *Ibid.*
678 *Ibid.*
679 *Ibid.* at 5.
680 *Supra* note 243.

flexpipe[681] and amendments to the public involvement programs in response to the Alberta Court of Appeal Decision in *Kelly*.[682]

4. ERCB STAFF REVIEW AND ANALYSIS: *TOTAL E&P CANADA LTD. SURFACE STEAM RELEASE OF 18 MAY 2006 — JOSLYN CREEK*[683]

The *Total Incident Report* arose out of a steam release incident in May 2006 at the Joslyn Creek SAGD operation (Joslyn Creek Scheme) operated by Total E&P Canada Ltd. (Total). The steam release occurred near the first well pair in Pad 204 of the Joslyn Creek Scheme and resulted in a crater approximately 125 m by 75 m, with projectiles travelling up to 300 m horizontally from the crater. A dust plume about 1 km long stretched to the southwest of the steam release point.

ERCB staff identified several instances of noncompliance in Total's scheme operations. First, Total was operating at significantly higher pressures than the 1800 kilopascals (absolute) described in its application. Further, according to cls. 1(2) and (3) of Total's ERCB approval for the Joslyn Creek Scheme, Total was required "to notify and obtain approval from the Board for any substantive alteration or modification to the applied-for scheme design or equipment,"[684] which it failed to do. ERCB staff concluded that the steam release incident would not have occurred if Total had been operating within its applied-for bottom hole pressure.[685] Further, Total failed to put alarms and automatic shutdowns in place for wells exceeding the bottom hole reservoir fracture pressure of 1800 kilopascals (absolute) as it suggested it would do in its application.[686] Finally, Total exceeded the maximum approved wellhead injection pressure of 1800 kilopascals (absolute) as contained in *Directive 051: Injection and Disposal Wells — Well Classifications, Completions, Logging, and Testing Requirements*.[687]

The ERCB ultimately concluded that the incidents of non-compliance coupled with the caprock geology led to the steam release incident.[688]

The *Total Incident Report* is informative, as Total's steam release incident has prompted the ERCB to implement changes to its application process and requirements based on several interim findings. The ERCB is currently assessing the need for additional requirements and regulatory changes.[689] For example, since the incident, the ERCB has implemented a number of initiatives to address the issues identified in the incident reports of Total and ERCB staff. First, the ERCB has initiated a rewrite of *Directive 051* to specifically address changes for

681 ERCB, *Directive 056: Process for Pipeline Applications for Fiberspar, Flexpipe, or Flexsteel Composite Pipes* (Calgary: ERCB, 2009). This document was released as an update to the 2008 edition of *Directive 056*, *ibid.*

682 *Supra* note 444. See also ERCB, Bulletin 2009-41, *supra* note 457.

683 ERCB, *Total E&P Canada Ltd. Surface Steam Release of May 18, 2006 — Joslyn Creek SAGD Thermal Operation*, Staff Review and Analysis (Calgary: ERCB, 2010) [*Total Incident Report*].

684 *Ibid.* at 9.

685 *Ibid.*

686 *Ibid.* at 10.

687 ERCB, *Directive 051: Injection and Disposal Wells — Well Classifications, Completions, Logging, and Testing Requirements* (Calgary: ERCB, 1994) [*Directive 051*].

688 *Total Incident Report*, *supra* note 683 at 28.

689 *Ibid.* at 6-7.

thermal in situ operations.[690] New SAGD scheme or amendment applications are to provide information addressing caprock integrity and maximum injection bottomhole pressures, with the intent that the ERCB will use this information to set maximum injection bottomhole pressures in all thermal in situ scheme approvals.[691] In addition, the ERCB has partnered with the Geology and Reserves Group and Alberta Geological Survey to study caprock integrity.[692]

5. ERCB *DRAFT DIRECTIVE: REQUIREMENTS FOR WATER MEASUREMENT, REPORTING, AND USE FOR THERMAL IN SITU OIL SANDS SCHEMES*[693]

The *Draft Directive* was developed by the ERCB and Alberta Environment (AENV) and is part of a provincial strategy to enhance water conservation in Alberta, generally applying to all thermal in situ oil sands schemes (new and existing) in the Athabasca, Cold Lake, and Peace River Oil Sands Areas (other than for those schemes that meet certain exceptions).[694] The requirements of the *Draft Directive* will only apply to existing thermal in situ schemes if the licensee applies for an expansion to the scheme's bitumen processing capacity or steam generation capacity.[695] In any event, the *Draft Directive* would apply to all existing schemes after it has been effective for five years.[696] Relaxations to water use limits may be available.

The *Draft Directive* proposes continuous improvement practices for water conservation efficiency and productivity on operators by limiting the use of fresh and brackish water resources, maximizing produced water recycle, improving the measurement and reporting of all major water streams at thermal in situ oil sands schemes, and minimizing the disposal of water from these schemes.[697] The *Draft Directive* sets out new requirements for water measurement accuracy; reporting of water streams to the Petroleum Registry of Alberta and AENV; ERCB injection facility water balance; maximum limits on fresh and brackish water use; and minimum limits on produced water use.[698]

6. ERCB *DRAFT DIRECTIVE: OIL AND GAS DEVELOPMENT WITHIN OR PROXIMAL TO WATER BODIES*[699]

The *Water Bodies Draft Directive*, jointly developed by the ERCB, AENV, Alberta Sustainable Resource Development, and the Special Areas Board of Alberta Municipal Affairs, imposes requirements "designed to provide a consistent, field-applicable methodology that can be used to identify and delineate water bodies and to accurately determine whether a new oil and gas development will meet the water body setback

690 *Ibid.* at 7.
691 *Ibid.* at 6-7.
692 *Ibid.* at 7.
693 ERCB, *Draft Directive: Requirements for Water Measurement, Reporting, and Use for Thermal In Situ Oil Sands Schemes* (Calgary: ERCB, 2009) [*Draft Directive*].
694 See also Government of Alberta, *Water for Life: Alberta's Strategy for Sustainability* (Edmonton: Alberta Environment, 2003), online: Government of Alberta <http://www.waterforlife.alberta.ca/documents/wfl-strategy_Nov2003.pdf>.
695 *Draft Directive, supra* note 693 at 7.
696 *Ibid.* at 9.
697 *Ibid.* at 2.
698 *Ibid.* at 3.
699 ERCB, *Draft Directive: Oil and Gas Development Within or Proximal to Water Bodies* (Calgary: ERCB, 2009) [*Water Bodies Draft Directive*].

requirements."[700] For purposes of the *Water Bodies Draft Directive*, a "water body" is defined to include "any location where water flows or is present, whether or not the flow or the presence of water is continuous, seasonal, intermittent, or occurs only during a flood."[701] The absence of water due to dry conditions is not indicative that a water body does not exist.[702] Further, temporary pooling of water that "does not induce change in soil and vegetation" will not be considered a water body.[703]

Although the *Water Bodies Draft Directive* focuses primarily on wells and facilities requiring licensing pursuant to *Directive 056*, the directions provided with respect to identifying and delineating water bodies are also applicable to all ERCB-regulated activities that are required to be set back from water bodies, including oilfield waste management facilities, drilling waste disposals, and material storage.[704]

7. ERCB BULLETIN 2010-04: *DIRECTIVE 019: COMPLIANCE ASSURANCE — ENFORCEMENT* (VOLUNTARY SELF-DISCLOSURES)[705]

Bulletin 2010-04 provides clarification with respect to the self-disclosure guidelines in *Directive 019*.[706] The self-disclosure policy encourages that noncompliances be identified, reported, and corrected by licensees. However, the ERCB clarified that where a licensee is required to report or provide notification of an activity, event, or incident pursuant to an Act, regulation, directive, or other instrument, the mandatory report is not considered to be voluntary self-disclosure.[707]

8. ERCB *DIRECTIVE 058: OILFIELD WASTE MANAGEMENT REQUIREMENTS FOR THE UPSTREAM PETROLEUM INDUSTRY*[708]

In Bulletin 2009-26: "Requirements on Waste Transport by Pipeline and Waste Tracking,"[709] the ERCB announced the addition of "waste transport by pipeline" as a disposition type that requires tracking and reporting pursuant to *Directive 058*.

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700 *Ibid.* at 2.

701 *Ibid.* at 5. This definition was imported from the *Water Act*, R.S.A. 2000, c. W-3, s. 1(1)(ggg).

702 *Water Bodies Draft Directive, ibid.* at 5-6.

703 *Ibid.* at 5.

704 *Ibid.* at 2. Notably, the requirements of the *Water Bodies Draft Directive* do not apply to pipelines.

705 ERCB, Bulletin 2010-04, "*Directive 019: Compliance Assurance — Enforcement* (Voluntary Self-Disclosures)" (27 January 2010) [ERCB, Bulletin 2010-04].

706 *Supra* note 372.

707 ERCB, Bulletin 2010-04, *supra* note 705.

708 ERCB, *Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry* (Calgary: ERCB, 1996) [*Directive 058*].

709 ERCB, Bulletin 2009-26, "Requirements on Waste Transport by Pipeline and Waste Tracking" (31 July 2009).

9. ERCB *DIRECTIVE 060: UPSTREAM PETROLEUM INDUSTRY FLARING, INCINERATING, AND VENTING*[710]

The fugitive emissions management requirements set out in s. 8.7 of *Directive 060* took effect on 1 January 2010.[711] Operators are required to implement a program to detect and repair leaks; a failure to do so could result in a High Risk Enforcement Action being issued.[712] The program must be implemented at the facility, must address leak repairs within a specific time frame, and must require repairs that meet the economic test found in CAPP's *Best Management Practice for Fugitive Emissions Management.*[713]

10. ERCB *DIRECTIVE 062: COALBED METHANE CONTROL WELL REQUIREMENTS AND RELATED MATTERS*[714]

Revisions to *Directive 062* became effective as of 28 January 2010.[715] The amendments allow for an area where desorption control wells are no longer needed for specific coal zones,[716] allow a 30-day flow period before control wells are required, permit applications for temporary exploration deferral of control well requirements for the Taber and McKay coal zones, provide further details on horizontal control wells and coal bed methane production wells, and clarify the minimum requirements and the validation process for control wells.[717] In addition, revisions were made to *Directive 062* that reflect the mandatory requirement for electronic application submissions.[718]

11. ERCB *DIRECTIVE 065: RESOURCES APPLICATIONS FOR OIL AND GAS RESERVOIRS*[719]

Amendments to *Directive 065* clarify minimum well spacing application requirements given risk-based application processing pathways.[720] Further, the amendments to *Directive 065* implement Unit 7, which supersedes the former s. 1.6 of the Directive. Unit 7 clarifies application requirements, identifies the criteria applied by the ERCB in the decision process, and provides more comprehensive information regarding standards for well spacing.[721] Pursuant to Bulletin 2010-07: "Changes to Well Spacing Within Development Entities No. 1 and No. 2 and Spacing Notification Requirements,"[722] the ERCB advised that well spacing

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710 ERCB, *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting* (Calgary: ERCB, 2006) [*Directive 060*].

711 See ERCB, Bulletin 2009-44, "Reminder of the January 1, 2010, Fugitive Emissions Program Effective Date" (16 December 2009) at 1.

712 *Ibid.*

713 *Ibid.*

714 ERCB, *Directive 062: Coalbed Methane Control Well Requirements and Related Matters* (Calgary: ERCB, 2010) [*Directive 062*].

715 See ERCB, Bulletin 2010-05, "Revised *Directive 062: Coalbed Methane Control Well Requirements and Related Matters* Issued" (28 January 2010).

716 These changes are set out in the amended Appendix A of *Directive 062, supra* note 714.

717 *Ibid.* at 1-2.

718 See ERCB, Bulletin 2010-08, "Mandatory Electronic Application Submission (EAS): Resources Applications" (10 February 2010) at 1[ERCB, Bulletin 2010-08].

719 ERCB, *Directive 065: Resources Applications for Oil and Gas Reservoirs* (Calgary: ERCB, 2010) [*Directive 065*].

720 See ERCB, Bulletin 2009-33, "Changes to Special Well Spacing Application Process in *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs*" (7 October 2009) at 1.

721 *Ibid.*

722 ERCB, Bulletin 2010-07, "Changes to Well Spacing Within Development Entities No. 1 and No. 2 and Spacing Notification Requirements" (4 February 2010) [ERCB, Bulletin 2010-07].

regulations would be amended to increase baseline well densities and harmonize target areas within Development Entities No. 1 and No. 2.[723] A revised edition of *Directive 065* has been issued in this regard.

Bulletin 2010-08 indicated that as of 1 April 2010, *Directive 065* resource applications must be submitted electronically.[724] Further, Bulletin 2010-07 indicated that as of 4 February 2010, notice of proposed special well spacing applications no longer needs to be provided to surface landowners.[725]

12. ERCB *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*[726]

In response to the Court of Appeal decision in *Kelly*,[727] the ERCB issued Bulletin 2009-41,[728] which indicated that an error had been made in adopting an endpoint for the PAZ that went beyond the boundary of the EPZ, thereby failing to correspond with the definition of the PAZ provided in *Directive 071*.[729] The ERCB indicated that the ERCB H2S model would be calibrated to rectify the error such that the end point for the PAZ would fall within the outer boundary of the EPZ. As well, in accordance with *Kelly*, the ERCB concluded that the EAZ and the two sulphur dioxide zones found in *Directive 071* were unnecessary and were therefore removed from the Directive.[730]

In addition to these changes, the ERCB invited public comment on a draft edition of *Directive 071*, which would introduce an ERP maintenance form, expand corporate ERP requirements, require that licensees develop an ERP in accordance with a specific format, and clarify jurisdiction with respect to emergency response and developing protocols.[731]

13. ERCB *Directive 017: Measurement Requirements For Upstream Oil and Gas Operations*[732]

Revisions were made to *Directive 017* in October of 2009 to address heavy oil measurement and condensate and high vapour pressure liquids measurement.

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723 *Ibid.* at 2. These changes were made effective 1 April 2010, and well spacing regulation amendments were made to the *OGCR*, *supra* note 298: ERCB, Bulletin 2010-12, "Changes to *Directive 065: Resources Applications for Conventional Oil and Gas Reservoirs* and *Directive 062: Coalbed Methane Control Well Requirements and Related Matters*" (1 April 2010).

724 *Supra* note 718 at 1.

725 *Supra* note 722 at 3.

726 *Supra* note 445.

727 *Supra* note 444.

728 *Supra* note 457.

729 *Ibid.* at 2.

730 *Ibid.* at 3.

731 See ERCB, Bulletin 2010-11, "Invitation for Feedback on Draft Revised Edition of *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*" (12 March 2010).

732 ERCB, *Directive 017: Measurement Requirements for Upstream Oil and Gas Operations* (Calgary: ERCB, 2009) [*Directive 017*].

14. PROPOSED LEGISLATIVE FRAMEWORK FOR IN SITU COAL DEVELOPMENT

On 20 October 2009, the ERCB released the proposed legislative and regulatory changes for in situ coal gasification and liquefaction schemes.[733] The *Proposed Legislative Framework for In Situ Coal Development*[734] makes several key recommendations, including that in situ coal developments should be classified as schemes to be approved under the *Coal Conservation Act*[735] and the *Coal Conservation Regulation*;[736] the licensing of associated wells, facilities, and pipelines should be done pursuant to the *OGCA*, the *OGCR*, the *Pipeline Act*, and the *Pipeline Regulations*; participant involvement programs should meet *Directive 056* as a minimum; coal rights should be obtained prior to an application for a well licence for an evaluation well; prior to an application being made, the coal, petroleum, and natural gas rights should be obtained for all lithologic units above the targeted coal seam; and the ERCB may collect security deposits for abandonment and reclamation of in situ coal schemes.[737] The ERCB is currently in the process of finalizing the proposed changes.[738]

C. SURFACE RIGHTS BOARD

Review of the annual compensation provisions of a surface lease are within the jurisdiction of the SRB pursuant to s. 27 of the *SRA*. A review is triggered when, after 12 months of unsuccessful negotiation, either party files an application under s. 27(8) for the Board to determine the issue. In order to trigger the renegotiation, an operator is required by s. 27(5) of the *SRA* to give notice to a lessor or respondent either of its own wishes to have the rate of compensation reviewed, or of the lessor or respondent right to a review.

In January 2010, the SRB issued a one-page guideline that applies to all applications made pursuant to s. 27 of the *SRA*, including applications regarding surface leases and ROEs that were made before 1 July 1983.[739] While the guideline retains the discretion of the SRB in individual circumstances, it states what would otherwise appear to be the practice of the SRB in respect of the required s. 27 "notice" from the operator to be that the "date that 'notice' is required to be given by the operator under s.27(14) will be every 5 years from the 4th anniversary of the date the surface lease commenced or the right of entry order was made."[740]

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733 See ERCB, Bulletin 2009-36, "Invitation for Feedback on Proposed Legislative Framework for In Situ Coal Schemes" (20 October 2009) [ERCB, Bulletin 2009-36].

734 ERCB, *Proposed Legislative Framework for In Situ Coal Development* (Calgary: ERCB, 2009) [*Proposed Legislative Framework*].

735 R.S.A. 2000, c. C-17.

736 Alta. Reg. 270/81.

737 *Proposed Legislative Framework*, *supra* note 734 at iii.

738 ERCB, Bulletin 2009-36, *supra* note 733.

739 SRB, Guideline 1.2010, "Interpretation of 'Notice' Under Section 27(4) and Section 27(14)."

740 *Ibid.*