RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO OIL AND GAS LAWYERS 2007 — 2008

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This article highlights regulatory and legislative developments during the period of May 2007 through April 2008 that are of interest to oil and gas lawyers. The article primarily examines decisions and other related jurisprudence of the National Energy Board and the Alberta Energy and Utilities Board, the latter of which was split into the Energy Resources Conservation Board and the Alberta Utilities Commission on 1 January 2008. Additionally, the article details policy and legislative developments affecting the National Energy Board and the two new Alberta regulators. Regulatory developments at the Alberta Surface Rights Board and in other jurisdictions are also considered.

Cet article souligne les développements réglementaires et législatifs qui se sont produits entre mai 2007 et avril 2008 et qui peuvent intéresser les avocats travaillant dans le domaine gazier et pétrolier. L'article examine essentiellement les décisions et autre jurisprudence de l'Office national de l'énergie et du Alberta Energy and Utilities Board, ce dernier ayant été divisé en Energy Resources Conservation Board et Alberta Utilities Commission le 1er janvier 2008. En outre, l'article donne le détail sur le développement de la politique et des lois touchant l'Office national de l'énergie et les deux nouveaux organismes de réglementation albertains. Les développements réglementaires du Alberta Surface Rights Board et des autres ressorts sont également pris en compte.

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I. INTRODUCTION

This article highlights regulatory and legislative developments during the period of May 2007 through April 2008 that are of interest to oil and gas lawyers. The article primarily examines decisions and other related jurisprudence of the National Energy Board (NEB) and the Alberta Energy and Utilities Board (AEUB), the latter of which was split into the Energy Resources Conservation Board (ERCB) and the Alberta Utilities Commission (AUC) on 1 January 2008. Additionally, the article details policy and legislative developments affecting the NEB and the two new Alberta regulators. Regulatory developments at the Alberta Surface Rights Board (SRB) and in other jurisdictions are also considered.

II. REGULATORY DECISIONS AND RELATED JURISPRUDENCE

A. NATIONAL ENERGY BOARD

The NEB regulates the construction, operation, tolls, and tariffs of interprovincial and international oil and gas pipelines and power transmission facilities. The NEB also regulates the import and export of oil, natural gas, and electricity, and oil and gas activities on frontier lands and offshore areas not covered by provincial/federal management agreements. Recent decisions have dealt with projects intended to increase transportation capacity out of the Western sedimentary basin to handle increased oil sands production and facilities designed to receive and transport liquefied natural gas (LNG) in Eastern Canada. In 2007-2008, the NEB faced jurisdictional challenges from a First Nations perspective, as well as arguments over the potential economic impacts of facilities approvals on the commercial interests of third parties and the Canadian domestic public interest.

1. DECISION OH-3-2007: *ENBRIDGE SOUTHERN LIGHTS PROJECT*[1]

The Southern Lights Project was approved by the NEB in February 2008. At the core of the Project was the reversal and reconfiguration of Enbridge Pipeline Inc.'s (EPI) Line 13 from the Canada/United States border near Gretna, Manitoba to Edmonton, Alberta to transport diluent (that is, light hydrocarbons used to dilute bitumen and heavy oil to allow the transportation of those substances by pipeline) sourced in the Chicago area through the U.S. portion of Line 13. In addition to considering the first federally regulated diluent pipeline, the NEB had to consider approximately $350 million in proposed new pipeline facilities to replace the southbound crude oil capacity on the Enbridge Inc. (Enbridge) system that would be lost due to the conversion of Line 13; tolling principles and methodologies for both the diluent pipeline and the capacity replacement facilities; arguments respecting potential impacts of the Project on domestic interests; and a motion by the Standing Buffalo Dakota First Nation (Standing Buffalo) challenging the NEB's jurisdiction to consider the Project on its merits, based on the Supreme Court of Canada's decision in *Haida Nation v. British Columbia (Minister of Forests)*.[2]

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1 *Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP and Enbridge Pipelines* (February 2008), NEB Decision OH-3-2007, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/441806/456607/499885/499563/A1DQ5_-_Reasons_For_Decision.pdf?nodeid=499564&vernum=0>.

2 2004 SCC 73, [2004] 3 S.C.R. 511 [*Haida*].

The central justification for the Southern Lights Project was the need for increased, low cost diluent supply for the Canadian oil sands industry to enable growth in bitumen production. Among other things, the NEB concluded that the Project was a "cost-effective solution for diluent transportation through an innovative combination of existing infrastructure and new build."[3]

a. Project Overview

The Southern Lights Project consisted of two components: the Diluent Pipeline Project and the Capacity Replacement Project.

The Diluent Pipeline Project involved the transfer of the Canadian portion of EPI's Line 13 to Enbridge Southern Lights GP (ESL). Line 13 would be removed from southbound crude oil service and reversed to transport diluent, and existing Line 13 pump stations and valve sites would be modified accordingly. The applicants requested leave under s. 74 of the *National Energy Board Act*[4] and an order under s. 129(1.1) of the *NEB Act* to give effect to the transfer of facilities; an order under s. 58 of the *NEB Act* approving the Line 13 reversal and the necessary facilities modifications; and approval under Part IV of the *NEB Act* in respect of the tolls and tariffs that would be applicable to the Diluent Pipeline Project.

The Capacity Replacement Project was comprised of the construction of a new 288 kilometre (km) nominal pipe size (in inches) 20 light sour crude oil pipeline running from Cromer, Manitoba to the Canada/U.S. border near Gretna, Manitoba; the addition of pumping and related facilities and pump station piping at three existing EPI pump station sites; and a number of modifications to EPI's Line 2. The applicants requested a certificate of public convenience and necessity under s. 52 of the *NEB Act* in relation to the new pipeline; orders under s. 58 of the *NEB Act* in relation to the pumping and related facilities and pump station piping, and with respect to the Line 2 modifications; approval under Part IV of the *NEB Act* in respect of the tolling methodology that would apply to the Line 2 modifications and the new pipeline prior to and following the transfer of Line 13 from EPI to ESL.

b. Facilities Approval

The NEB noted that in approving a facility, it would normally consider capacity relative to the apparent demand in determining whether the facility was needed and would be used at a reasonable level over its expected economic life. "With respect to the Diluent Pipeline Project, the Board [was] of the view that there [was] demand to increase diluent imports, [but] there [was] some uncertainty with respect to potential future volumes."[5] Further, the diluent pipeline had not been sized to expected volumes, as the applicants were proposing the reversal of an existing line.[6]

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3 *Supra* note 1 at 66.
4 R.S.C. 1985, c. N-7 [*NEB Act*].
5 *Supra* note 1 at 21.
6 *Ibid.*

Nevertheless, the NEB was satisfied that the various components of the Southern Lights Project would be used at a reasonable level over their economic life given Enbridge's assessment of diluent supply and markets, and the crude oil supply forecast, which supported the need for increased diluent supply.[7] The NEB determined that there would be sufficient crude oil supply to support the long-term operation of an import diluent pipeline and that there was a need for additional crude oil pipeline capacity out of the Western Canadian Sedimentary Basin to transport growing oil sands production to market.[8] The NEB also noted that shippers had accepted contractual arrangements that covered the entire revenue requirement for the Southern Lights Project for a period of 15 years (albeit for only 43 percent of the available capacity) and as such, "adequate provisions exist[ed] for recovery of capital, operating expenses and financing costs for the applied-for facilities."[9]

c. Impacts of the Project on Domestic Interests

The Communication, Energy and Paperworkers Union of Canada argued that the project would pose a risk to Canadian economic development by undermining investment in Canadian industries as it would predominantly be used to facilitate the export of under-refined heavy oil, thus limiting supplies for Canadian requirements; hindering the stimulation of investment, economic development, and job creation in Canada; and decreasing the degree of energy security for Canadians. The NEB rejected these arguments, concluding that there was an adequate supply of oil for both existing refineries and increased movements to new markets. The NEB also stated that it was not inclined to interfere in the market, based on its view that well-functioning markets bring about efficient outcomes that are in the public interest.[10]

d. Tolls and Tariffs Approvals

The NEB approved the proposed tolling methodology for the diluent pipeline, which was embodied in the transportation service agreements between ESL and its contracted shippers. The methodology provided for tolls to be established on a full cost of service basis. Tolls for a given year would be subject to an adjustment to be made after year-end to reflect differences between the estimated cost of service and the actual cost of service, revenue from uncommitted tolls, and power savings for volumes of diluent that were not transported all the way to Edmonton. Two tolls would be offered: (1) committed tolls applicable to the contractual volumes of shippers who had executed transportation service agreements; and (2) uncommitted tolls applicable to shippers who had not executed long-term transportation service agreements and volumes of contracted shippers over and above their committed volumes. Shippers who had signed transportation service agreements paid the negotiated tolls, had price certainty, and unapportioned access to pipeline capacity. The proposed uncommitted toll would be at least twice the committed toll.

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7 *Ibid.*

8 *Ibid.* at 20.

9 *Ibid.*

10 *Ibid.* at 21.

In approving the proposed methodology, the NEB stated that it would monitor the application of the approved tolling principles to ensure that they would continue to result in just and reasonable tolls during the life of the diluent pipeline. The NEB also designated ESL (the owner of the diluent pipeline) as a Group 2 company for the purposes of financial regulation. However, as the diluent pipeline was the first of its kind to be regulated by the NEB, the NEB determined that additional regulatory oversight was appropriate to ensure that all shippers that nominate volumes to the line would be granted reasonable access and that the premium in the toll for uncommitted volumes did not become an unreasonable impediment to potential spot shippers. The NEB imposed a number of information filing requirements on ESL and also noted that if disputes arose in respect of the tolls charged or the terms of access to or transportation on the pipeline, all shippers (whether they had signed a long-term contract or not) would have the right to complain to the NEB. The NEB also directed ESL to file a Code of Conduct with the Board to deal with potential conflicts of interest if an affiliate of ESL were to participate in the diluent market and the transportation of diluent on the pipeline.[11]

With respect to the Capacity Replacement Project, the NEB held that it was appropriate that the capital and operating costs associated with the project be borne by Enbridge's mainline shippers during the period between the in-service date of the Capacity Replacement Project and the closing date for the Line 13 transfer. The Board based its decision on the fact that mainline shippers would benefit from the additional southbound crude oil transportation capacity that would be provided by the Capacity Replacement Project prior to the transfer and reversal of Line 13. Following the closing of the transfer, there would be no impact on mainline tolls as the purchase price paid by ESL to EPI in relation to the Line 13 facilities was calculated to match the costs associated with the Capacity Replacement Project.[12]

e. Motion by Standing Buffalo Dakota First Nation[13]

The Standing Buffalo filed a Notice of Motion during the proceeding.[14] In essence,

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11 *Ibid.* at 53.

12 *Ibid.* at 65.

13 *Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP and Enbridge Pipelines* (Notice of Motion by Standing Buffalo Dakota First Nation) (10 October 2007), NEB Decision OH-3-2007, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/441806/456607/459849/461439/C-13-116-SBDFN_s._35_Notice_of_Motion-October_10-07_-_A1A6T3_?nodeid=481623& vernum=0>.

14 Standing Buffalo Dakota First Nation (Standing Buffalo) made essentially the same motion in respect of *Enbridge Pipelines: Alberta Clipper Expansion Project* (February 2008), NEB Decision OH-4-2007, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/92263/452395/465178/500099/500012/A1D5A3_-_Reasons_for_Decision_OH-4-2007.pdf?nodeid=500013&vernum=0> [Standing Buffalo Motion]; *TransCanada Keystone Pipeline GP Ltd.* (September 2007), NEB Decision OH-1-2007, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/418396/446070/478070/477791/A1A4H2_-_Reasons_for_Decision_OH-1-2007.pdf?nodeid=477856&vernum=0> [NEB Decision OH-1-2007]; *Enbridge Pipelines (Westspur) Inc. Alida to Cromer Capacity Expansion (ACCE) Project* (June 2007), NEB Decision OH-2-2007, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/205661/450715/470519/467939/A0Z4E5_-_Reasons_For_Decision.pdf?nodeid=467940& vernum=0>. The NEB's decisions on the motions were consistent with each other. Standing Buffalo filed applications with the NEB for a review of the NEB's Decisions in OH-1-2007 and OH-2-2007. Both were denied: Letter Decision from NEB to Chief Rodger Redman & Mervin C. Phillips (13 February 2008), OF-Fac-Oil-T241-2006-01 03,

Standing Buffalo argued with reference to the Supreme Court of Canada's decision in *Haida* that the NEB could only consider the substance of the Southern Lights Application once it had (1) established that Standing Buffalo had made a credible potential claim to the land subject to the Project; (2) determined the scope of the Crown's duty to consult; and (3) satisfied itself that the Crown's duty to consult had been fulfilled.[15] Standing Buffalo asserted that the NEB had to either order a representative of Canada to be present so that all parties could address the issue of jurisdiction with the representative of Canada present or it had to determine that it had no jurisdiction to consider the merits of the substantive application before it.

The NEB dismissed Standing Buffalo's Motion, concluding that the Board had "jurisdiction to make a final determination on the applications before it and [would] not require the attendance of a Crown official to discuss Standing Buffalo's claim."[16] The NEB noted the following:

- The NEB's regulatory approval process is designed to require a proponent to "take all reasonable steps to identify and contact Aboriginal people in the area of the proposed project prior to filing [its] application [with the Board]," ensuring that "potentially affected Aboriginal people have essential information about the project and can discuss their concerns and issues with the [proponent] in the early planning stages."[17] The applicant must provide "evidence related to its discussions with potentially affected Aboriginal people as well as details of the issues or concerns raised" and, where applicable, the manner in which those issues and concerns have been addressed.[18] "To the extent possible and within the parameters of procedural fairness, the Board has adopted a fair and flexible process that allows Aboriginal people to provide their views and evidence to the Board."[19] "Aboriginal people with unresolved concerns are encouraged to make their views known to the Board through … participation in the hearing," and the NEB "takes all of the evidence about Aboriginal rights and interests into consideration as part of its assessment of the project impacts and determination of whether the project is in the public interest."[20]

  In this case, the NEB concluded that Standing Buffalo participated fully in the proceeding and offered extensive evidence of its views and concerns about the

online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/418396/446070/482464/499206/A1D4C6_-_Letter_Decision_-_Standing_Buffalo_Review_of_OH-1-2007.pdf?nodeid=499207&vernum=0>; Letter Decision from NEB to Chief Rodger Redman & Mervin C. Phillips (6 December 2007), OF-FAC-Oil-E103-2007-01 04, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90552/205661/450715/474691/487551/A1C3J7_-_OH-2-2007_Application_for_Review_by_SBDFN_-_Board_Decision.pdf?nodeid=487441&vernum=0>. Standing Buffalo also filed an application for judicial review with the Federal Court of Appeal which was heard in the spring of 2008. See *Standing Buffalo Dakota First Nation v. Canada (A.G.)*, 2008 FCA 222, [2008] F.C.J. No. 1124 (QL).

15 Standing Buffalo Motion, *ibid.* at para. 8.

16 *Supra* note 1 at 12.

17 *Ibid.*

18 *Ibid.*

19 *Ibid.* at 11.

20 *Ibid.* at 12.

Southern Lights Project. Standing Buffalo was fully informed about the project through discussions with the applicants, the applicants' filings, and participation in the hearing and had full opportunity to voice its views and concerns to the NEB. The NEB was "satisfied that it [had] the evidence it [needed] to determine the project impacts on various interests, including those of Standing Buffalo, and to determine whether the project [was] in the public interest."[21]

- "The Board cannot be directed by other government authorities, nor does the Board have the authority to direct the activities of other government authorities.… Those government authorities may have their own specific requirements for issuance of their authorizations and may carry out Aboriginal consultation in respect of their decisions, where appropriate."[22] The NEB is not in a position to assess whether the legal obligations of those authorities, including the adequacy of their consultations, have been fulfilled in relation to those authorizations. "It is the responsibility of those government authorities to ensure that they have met their legal obligations and it is a matter for the courts, not the Board, if someone wishes to challenge their processes."[23]

2. DECISION GH-1-2006: *EMERA BRUNSWICK PIPELINE PROJECT*[24]

The Emera Brunswick Pipeline Project was approved by the NEB in May 2007. The project consisted of a new re-gasified natural gas transmission pipeline running from the Canaport™ LNG Terminal at Mispec Point, New Brunswick, to the Canada/U.S. border near St. Stephen, New Brunswick. Emera Brunswick Pipeline Company Ltd. (EBPC) applied for a certificate of public convenience and necessity under s. 52 of the *NEB Act* authorizing the construction and operation of the pipeline and for orders under Part IV of the *NEB Act*[25] approving tolls for the pipeline and designating EBPC as a Group 2 company for the purposes of financial regulation.[26]

The federal Minister of the Environment referred the project to a review panel under the *Canadian Environmental Assessment Act*.[27] For the first time, however, under s. 43 of the *CEAA*, the Minister approved the use of the NEB's regulatory process for assessing the environmental effects of the project as a substitute for an environmental assessment by a review panel.[28]

The central purpose for the pipeline was to connect a new incremental supply source to existing markets. Among other things, the NEB concluded that although the investment in

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21 *Ibid.*
22 *Ibid.* at 12.
23 *Ibid.*
24 *Emera Brunswick Pipeline Company Ltd.* (May 2007), NEB Decision GH-1-2006, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90550/408788/408789/466317/465027/A0Z1F4_-_Reasons_for_Decision_-_Emera_Brunswick_Pipeline_Company_Ltd._-_GH-1-2006?nodeid=465121&vernum=0> [NEB Decision GH-1-2006].
25 *Supra* note 4, ss. 58.5-72.
26 *Supra* note 24 at 1.
27 S.C. 1992, s. 37 [*CEAA*].
28 *Supra* note 24 at 3.

the pipeline was underpinned by demand for natural gas in the Northeast U.S., the pipeline would provide a reliable incremental supply source for the Maritimes, which could be accessed through direct connection, swaps, and backhauls.[29] The NEB also concluded that the incremental supply facilitated by the pipeline would benefit energy consumers in the Maritimes by: (1) promoting the long-term growth of the regional energy market in Canada and (2) decreasing short-term price volatility caused by supply/demand pressure and promoting long-term price stability in the Maritimes and Northeast U.S.[30]

Noteworthy topics addressed by the Board in its decision included: (1) the sufficiency of LNG supply;[31] (2) public safety risks associated with the pipeline;[32] (3) potential impacts on the value of property in the vicinity of the pipeline;[33] (4) routing alternatives;[34] (5) bypass and potential duplication of existing facilities;[35] and (6) the sufficiency of EBPC's public consultation efforts.[36]

a. Liquefied Natural Gas Supply

The source of supply for the pipeline was the Canaport™ LNG Terminal, which was capable of re-gasifying up to 1,000,000 million British therma units (MMBtu) per day of pipeline quality natural gas. The pipeline would be capable of handling 850,000 MMBtu/day on a firm basis, and an additional 150,000 MMBtu/day on an interruptible basis. All of the gas would be owned by Repsol Energy Canada Ltd. (Repsol) (the Canadian subsidiary of Repsol YPF, Spain's largest integrated oil company), which had entered into a 25 year firm service transportation agreement with EBPC for 791,292 gigajoule (GJ) per day (or approximately 750,000 MMBtu/day) of capacity on the Emera Brunswick Pipeline. Repsol stated that it had sufficient LNG under contract to assure that the pipeline would be highly utilized, indicating that it would initially source LNG for the terminal from Trinidad and Tobago but that it might also rely on other sources of supply from Repsol YPF's portfolio or third party sponsored projects.

The NEB concluded that there was evidence of sufficient supply in this case to satisfy the supply requirements of the Emera Brunswick Pipeline.[37] The NEB noted that the issue of supply was somewhat unique for this project, which relied on a portfolio of assets for its supply, in comparison to more typical projects that source their supply from dedicated gas fields. The NEB stated that "[w]hile a portfolio of assets may not provide a specific dedicated supply field to a project, there [would be] flexibility to draw from various fields and therefore mitigate potential supply problems in any given supply basin."[38]

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29 *Ibid.* at 34.
30 *Ibid.* at 37.
31 *Ibid.* at 29.
32 *Ibid.* at 18-19.
33 *Ibid.* at 60-61.
34 *Ibid.* at 69-70.
35 *Ibid.* at 80-82.
36 *Ibid.* at 190-92.
37 *Ibid.* at 29.
38 *Ibid.*

b. Public Safety

A number of interveners expressed concern over the risks associated with having the pipeline built through the City of Saint John, and in particular near residences and institutions like the Saint John Regional Hospital. EBPC filed a quantitative risk analysis for the pipeline prepared by a recognized consulting firm, which concluded that the public safety risks associated with the pipeline were within acceptable limits and in the "[i]nsignificant risk regions."[39] EBPC also took the position that by meeting or exceeding all requirements for pipeline safety prescribed by government regulations and industry standards, the pipeline would meet or exceed established risk criteria. Interveners provided analyses of their own purporting to show that the pipeline posed unacceptably high risks to public safety.[40]

The NEB concluded that EBPC had taken "an acceptable approach to identifying and assessing the risks associated with … the proposed Pipeline."[41] The NEB specifically noted that "the urban section of the … Pipeline [was] designed for the requirements of a Class 3 location designation, which meets or exceeds the requirements of CSA Z662-03 for the types of development existing and anticipated along the pipeline route, including schools and institutions where evacuation may be difficult."[42] The Board also accepted the report of EBPC's consultant as accurately portraying the risks associated with the pipeline.[43]

However, given the level of concern expressed by interveners with respect to public safety, the NEB imposed a condition in its approval, requiring EBPC to file its emergency procedures manual 60 days prior to the commencement of the operation of the pipeline,[44] rather than the more typical 14 days, to provide NEB specialists with an appropriate amount of time to review the manual and resolve any concerns identified. The NEB also required that EBPC continue to consult with stakeholders through the development of the emergency procedures manual and that within six months after the commencement of operation of the pipeline, EBPC conduct a full emergency response exercise focused at potentially problematic locations along the pipeline route to evaluate the effectiveness of its emergency preparedness and response program.[45] The NEB also made reference to its authority to audit an owner's programs and systems and concluded that such audits, together with the provisions of the *Onshore Pipeline Regulations, 1999*,[46] the NEB-imposed conditions on the approval, and EBPC's commitments, were sufficient to ensure that the pipeline would be operated in a safe manner.[47]

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39 *Ibid.* at 17. See also Emera Brunswick Pipeline Company Ltd., *Application to the National Energy Board: Brunswick Pipeline Project* (23 May 2006), online: NEB <https://www.neb.one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90550/408788/408789/413976/408713/B-1-a_--_A0U3F6_-_Application.pdf?nodeid= 408717&vernum=0>.

40 See e.g. Saint John Fire Department, *Risk Analysis of Emera Brunswick Pipeline Company Ltd.'s preferred natural gas pipeline corridor through The City of Saint John* (22 September 2006), online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe?func=ll&objId=432372&objAction=browse>.

41 *Supra* note 24 at 18-19.

42 *Ibid.* at 19.

43 *Ibid.*

44 *Ibid.* at 255.

45 *Ibid.* at 256.

46 S.O.R./1999-294.

47 *Supra* note 24 at 18-19, 23-25, 54.

c. Property Value Impacts

Interveners argued that the existence of the high pressure natural gas pipeline would have an adverse effect on the value of property near the pipeline and asserted that the NEB should impose a condition that EBPC purchase, at fair market value, the property of any owner within 500 feet of the pipeline. EBPC argued that the pipeline would not have any such impacts, relying on a consultant's study of the property value impacts of natural gas pipelines focusing on Maritime-specific areas.[48]

The NEB found that two factors could negatively impact property values near the pipeline. First, increased public awareness of the pipeline could produce negative perceptions, but these "would likely dissipate over time as the public became more accustomed to the presence of the pipeline and … more informed" through ongoing public consultation efforts by the proponent.[49] Second, accidents and malfunctions could impact property values, but there were "multiple layers of protection [in place] to ensure the safe operation of the pipeline."[50] As such, the NEB concluded "that any negative socio-economic impacts on property values would be unlikely, or short-term and reversible."[51]

d. Routing Alternatives

Several routing alternatives were considered by EBPC using a number of evaluative criteria. Interveners focused their efforts on arguing for a marine crossing of Saint John Harbour rather than an overland route through the City of Saint John. EBPC had rejected the possibility of a marine route at an early stage in its route selection process on the basis of initial feasibility studies that had identified cumulative effects concerns and impracticalities relating to higher safety, technical, cost, schedule, and environmental risks. The NEB concluded that EBPC's preferred route was appropriate and should be approved, finding that EBPC's corridor evaluation approach was "reasonable, objective, and appropriate with regard to its Project purpose and the interests of those affected."[52]

e. Bypass and Duplication of Facilities

The Anadarko group of companies (Anadarko) intervened in relation to its proposed Bear Head LNG Project and argued that the pipeline would be a bypass of the Canadian Maritimes and Northeast Pipeline (M&NP) because it would duplicate existing M&NP facilities that could be made capable of providing similar service. Anadarko submitted that the pipeline "would be a 'parasitic' bypass [as] it would tap into the economies of scale and absorb virtually all of the existing and readily expandable capacity of the US segment of the M&NP system," while avoiding payment of the postage stamp toll on the Canadian portion of the

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48 *Ibid.* at 60.

49 *Ibid.*

50 *Ibid.*

51 *Ibid.* at 60-61.

52 *Ibid.* at 70. Subsequently, an intervener group sought leave from the Federal Court of Appeal for review of the NEB's decision in this regard, arguing that the NEB had failed to properly consider a marine routing alternative. However, the Federal Court of Appeal refused leave on 20 September 2007 in *Friends of Rockwood Park v. Emera Inc.*, 2007 FCA 300, [2007] F.C.J. No. 1238 (C.A.) (QL).

M&NP system.[53] Anadarko also argued that these circumstances would provide the Canaport™ LNG Terminal with an unfair competitive advantage (through lower pipeline tolls on the Emera Brunswick Pipeline) over the Anadarko group's Bear Head LNG Project.

The NEB rejected the argument that the pipeline was a "bypass" pipeline on the basis that there were no existing facilities that could perform the same functions as the proposed pipeline, and there was no evidence that an expansion of the M&NP system to provide the same function could or would be undertaken by the owner. The NEB also concluded that despite the fact that the Emera Brunswick Pipeline would rely on the U.S. portion of the M&NP system, the pipeline was a "stand-alone" pipeline because (1) "it [would be] owned by a different corporate entity than the M&NP system"; (2) "its facilities are physically separate or distinguishable from the M&NP facilities"; and (3) "it would provide a unique and separate service from [those] service[s] already provided by the M&NP system, and therefore is functionally distinguishable from M&NP."[54]

The NEB acknowledged that the pipeline might give a transportation advantage to the Canaport™ LNG Terminal over the Bear Head Project. The NEB stated, however, that its mandate was "neither to protect parties from competition nor to protect specific private interests … [and] … that the public interest [was] best served by allowing competitive forces to work, unless there [was] clear evidence of significant market dysfunction."[55] The NEB concluded that there was no evidence of such dysfunction in this case.[56]

f. Public Consultation

Although the NEB concluded that EBPC's public consultation program was adequate in a number of respects, the NEB determined that a number of aspects of the program could have been improved. Specifically, the NEB noted perceptions of incomplete notification of landowners around horizontal directional drill sites, allegations of unprofessional behaviour on the part of EBPC's land agents, negative public perception associated with EBPC's approach to securing support from the City of Saint John, and failure to identify whether a First Nation was a potentially affected party.[57] The NEB concluded that EBPC had not been effective in fully engaging the public and imposed a number of conditions in its approval of the pipeline designed to establish a basis for effective communication between EBPC and the local communities on a go-forward basis.[58]

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53 NEB Decision GH-1-2006, *ibid.* at 79.
54 *Ibid.* at 81.
55 *Ibid.* at 82.
56 *Ibid.*
57 *Ibid.* at 45.
58 *Ibid.* at 46-47.

3. DECISION RH-1-2007: *TRANSCANADA PIPELINES LIMITED RECEIPT POINT AT GROS CACOUNA*[59]

This decision involved an application by TransCanada PipeLines Limited (TransCanada) under Part IV of the *NEB Act* for an order approving Gros Cacouna, Quebec, as a new receipt point and affirming the applicability of the rolled-in and the point-to-point distance toll methodologies to the determination of tolls for services in respect of volumes received at the receipt point. TransCanada filed the application for the purpose of obtaining regulatory certainty from a tolling perspective to assist in the evaluation of the economics of the proposed Gros Cacouna LNG Terminal and re-gasification facility (the Cacouna LNG Project). That project was to be undertaken jointly by TransCanada and Petro-Canada Oil and Gas (Petro-Canada). The application did not include a request under Part III of the *NEB Act*[60] for approval to construct and operate the physical facilities that would be associated with the receipt point.

a. New Receipt Point

In approving the new receipt point, the NEB noted that TransCanada's evidence supporting the request was consistent with the requirements of its tariff procedure for adding receipt and delivery points. The NEB was satisfied that TransCanada had considered all relevant factors and that its treatment of requests for new receipt points was fair and equitable. "Given the long lead time and uncertainty associated with proposed LNG projects," the NEB found that requiring shippers to execute precedent transportation agreements (in this case, a 20 year firm transportation service agreement) was prudent.[61]

With respect to the potential economic impact to existing shippers, including the construction and operation of the necessary facilities on future commodity prices and resulting changes to total transportation costs on TransCanada's system, the NEB stated that its primary consideration in an application for a new receipt point was to ensure that resulting tolls were just and reasonable and not unjustly discriminatory.[62] The NEB noted that "[a]lthough favourable toll impacts and lowest possible tolls to all shippers [were] desirable, these [were] not always possible when all relevant factors [were] taken into consideration."[63] In this case, the NEB determined there was sufficient evidence of the benefits from a new source of LNG supply that may be provided by the new receipt point and associated facilities on the TransCanada system (approximate capital cost of $26 million) and the Trans Québec & Maritimes Pipeline Inc. system (approximate capital cost of $712 million).[64] The NEB stated that these benefits could include "enhanced service reliability, operational flexibility, and greater supply certainty to eastern users of the TransCanada system."[65] Given its

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59 *TransCanada PipeLines Limited* (July 2007), NEB Decision RH-1-2007, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90465/92833/92843/443945/472730/471076/A0Z7D1_-_Reasons_For_Decision.pdf?nodeid=470970&vernum=0>.

60 *Supra* note 4, ss. 29-72.

61 *Supra* note 59 at 19.

62 *Ibid.*

63 *Ibid.* at 19-20.

64 *Ibid.* at 10.

65 *Ibid.* at 20.

approval of the new receipt point, the NEB confirmed that "prudently incurred costs required to provide service Gros Caccouna [as would be determined in a future application] would be included in the determination of [TransCanada's] revenue requirement."[66]

b. Toll Methodology

The NEB also approved TransCanada's requests respecting the applicable toll methodology. It noted that it has a role in enabling the responsible development of Canada's energy sector for the benefit of Canadians, and that role includes "providing stakeholders with regulatory certainty with respect to toll methodology." Given the important role that toll design would play in the economic viability of the Cacouna LNG Project, the NEB stated that "it was appropriate, timely and prudent for the parties to seek assurance from the Board concerning the toll methodology prior to incurring significant expenditures [on the project] or entering into long-term commitments."[67]

The NEB also noted that "the toll methodology [would] likely have an impact on the supplier's perceptions of Canadian competitiveness in the global LNG market and its ability to yield attractive netbacks and subsequently secure supply."[68] The NEB outlined and reaffirmed the various principles and key considerations that have guided its decisions respecting toll methodology over the years and concluded that "the application of those principles and key considerations … [would] produce a tolling methodology [that would] form a sound basis for the development of the Canadian LNG market."[69]

In affirming the rolled-in toll methodology for the receipt point (under which the costs associated with the facilities necessary to connect the receipt point to the existing system would be included in the costs of the overall system borne by all shippers), the NEB pointed out the substantial level of integration that would be present between the new facilities and TransCanada's existing integrated system, as well as the significant benefits that TransCanada's shippers would enjoy from those facilities, including an incremental supply source and increased flexibility and reliability of the integrated system. The NEB also concluded that there was a reasonable expectation that shippers other than Petro-Canada would use the new facilities. Finally, the NEB noted that the point-to-point distance-based toll methodology, which ensures that shippers travelling comparable distances pay comparable tolls, was appropriate as it would promote proper price signals by recognizing differing distances between LNG facilities and their respective markets.[70]

The NEB determined that two issues should not be addressed in the context of TransCanada's application. The first was the extent to which gas interchangeability (that is, the ability to substitute one gaseous fuel for another in a combustion application without materially changing operational safety, efficiency or performance, or materially increasing air pollution emissions) should be addressed in TransCanada's tariff. The NEB determined that it did not have to deal with this issue in the context of this application, given that

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66 *Ibid.*
67 *Ibid.* at 3.
68 *Ibid.* at 38.
69 *Ibid.*
70 *Ibid.* at 42.

TransCanada was working with industry groups to develop gas interchangeability standards, and once developed, those standards would be brought to the NEB for approval. Second, the NEB held that the question of how the project would impact the goal of reducing greenhouse gases (GHG) in Canada under the *Kyoto Protocol to the United Nations Framework Convention on Climate Change*[71] was beyond the scope of the NEB's mandate in this proceeding.[72]

4. DECISION OH-1-2007: *TRANSCANADA KEYSTONE PIPELINE GP LTD.*[73]

In September 2007, the NEB issued a number of approvals in respect of the Keystone Pipeline Project. The Keystone Pipeline Project is a 1,235 km crude oil pipeline running from Hardisty, Alberta to the Canada/U.S. border near Haskett, Manitoba. The project consisted of the construction of two new pipeline segments and the conversion from natural gas to crude oil service of one existing segment of TransCanada's mainline natural gas system running from Burstall, Saskatchewan to Carman, Manitoba.[74]

TransCanada Keystone Pipeline GP Ltd.'s (Keystone) application was the second in a stepwise approach adopted by the company to obtaining the necessary regulatory approvals for the project. In February 2007, the NEB approved TransCanada's first application[75] relating to the transfer of the relevant segment of Line 100-1 from TransCanada to Keystone under ss. 74 and 59 of the *NEB Act*. In its second application, TransCanada requested several approvals relating to facilities and tolls, including a certificate of public convenience and necessity under s. 52 of the *NEB Act* authorizing the construction and operation of the pipeline; approval under s. 43 of the *Onshore Pipeline Regulations, 1999* for a change in-service of Line 100-1 from natural gas to crude oil service; and an order under Part IV of the *NEB Act* approving the proposed toll methodology and tariff for the pipeline.[76]

The NEB approved the construction and operation of the Keystone Pipeline, finding that the Keystone Pipeline would be used at a reasonable level over its economic life and that the associated tolls would be paid.[77] The NEB also approved the proposed tolling structure for the Keystone Pipeline, including committed tolls, which: (1) had been negotiated with shippers and (2) were not designed on a cost of service basis but had been designed to recover a combination of fixed and variable costs, with Keystone accepting certain financial risks.[78] The uncommitted tolls were designed to be competitive with alternative methods of transportation, and the maximum uncommitted toll consisted of the five year committed toll

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71 11 December 1997, 2303 U.N.T.S. 148, 37 I.L.M. 22 (entered into force 16 February 2005) [*Kyoto Protocol*].

72 *Supra* note 59 at 5.

73 NEB Decision OH-1-2007, *supra* note 14.

74 *Ibid.* at 1.

75 *TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd.* (February 2007), NEB Decision MH-1-2006, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/ 90464/ 90550/409774/410106/416758/455035/A0X8A0_-_Reasons_for_Decision_for_MH-1-2006.pdf? nodeid=455036&vernum=0> [NEB Decision MH-1-2006].

76 NEB Decision OH-1-2007, *supra* note 14 at 1.

77 *Ibid.* at 14.

78 *Ibid.* at 15.

plus a 20 percent premium.[79] The NEB concluded that the resulting tolls were "just and reasonable."[80] The NEB also concluded that the proposed tolling structure was "reflective of the differing levels of support and risk undertaken in connection with the Keystone Project" by committed versus uncommitted shippers, and as such, was not unjustly discriminatory.[81] Finally, the NEB found that the renewal rights and unapportioned access accorded to committed shippers did not result in unjust discrimination and that the open season and capacity allocation process undertaken by Keystone was consistent with its common carrier status under the *NEB Act*.[82] Given that neither the committed nor uncommitted tolls were determined on a traditional cost of service basis, but were set by reference to negotiated contracts, the Board designated Keystone as a Group 2 company for purposes of ongoing financial regulation by the NEB.[83]

A number of interveners (including the Communications, Energy and Paperworkers Union of Canada, the Alberta Federation of Labour, the Parkland Institute, and one individual) argued that if the Keystone Pipeline were approved, "there would be missed opportunities or negative consequences for domestic industries, employment and security of supply."[84] In its NEB Decision MH-1-2006 respecting the Keystone Pipeline, the NEB concluded that these kinds of domestic considerations were not relevant in the context of the application for approval of the transfer of ownership of the existing pipeline segment, and instead, that such considerations were "matters of broad public policy that were properly within the purview of Federal and Provincial governments."[85]

In this subsequent proceeding, however, the NEB noted that it has a very wide discretion in determining what to consider in deciding whether to grant a certificate of public convenience and necessity for a project under s. 52 of the *NEB Act*, which among other things, provides that the NEB "may have regard to any public interest that in the Board's opinion may be affected by granting or refusing an application."[86] The NEB noted that there is no precise definition of the concept of "public interest," and that the concept "may vary with [such factors as] the application, the location, the commodity involved, the various segments of the public affected by the decision and the purpose of the applicable section of the *Act*."[87] On this basis, the NEB concluded that the domestic concerns expressed by the interveners were public interest considerations relevant to the disposition of the application. The NEB also noted in its conclusions that as part of its regulatory framework, one of the NEB's goals is that "Canadians benefit from efficient energy infrastructure and markets … [and] well-functioning markets tend to produce outcomes that are in the public interest."[88]

Interveners relied on a study calculating the number of jobs that could be created if the Canadian refining industry were expanded to process 400,000 barrels per day of crude oil,

79 *Ibid.* at 16.
80 *Ibid.* at 19.
81 *Ibid.*
82 *Ibid.*
83 *Ibid.* at 21.
84 *Ibid.* at 50.
85 *Ibid.* at 56, citing *supra* note 75 at 21.
86 *Supra* note 4, s. 52; NEB Decision OH-1-2007, *ibid.* at 55.
87 NEB Decision OH-1-2007, *ibid.*
88 *Ibid.* at 56.

arguing that an opportunity to create Canadian jobs would be lost if the Keystone Pipeline were approved.[89] The NEB rejected this argument, concluding that the study did not support the proposition that an expansion of Canadian refining capacity would occur if the application were denied, noting that the market normally makes these types of decisions.[90] The NEB also dismissed the argument that approval of the Keystone Pipeline might frustrate the development of the domestic upgrading and refining industry by shortening supply, finding that projected supply would far exceed the takeaway capacity offered by the Keystone Pipeline.[91]

The NEB noted that the Keystone Pipeline would alleviate crude oil capacity constraints and the corresponding adverse economic impacts that would arise and concluded that Canadian requirements for crude oil would continue to be met if the Keystone Pipeline were approved. The absence of concern from feedstock users and the long-term contracts that had been signed by shippers on the Keystone Pipeline demonstrated that market participants had confidence that the market is working and would continue to work to meet long-term requirements for Canadian crude. The NEB also rejected the argument that the operation of the *North American Free Trade Agreement Between the Government of Canada, the Government of Mexico and the Government of the United States*[92] and the existence of export orders could have negative consequences for the security of supply if the Keystone Pipeline were approved.[93]

The NEB concluded that approval of the Keystone Pipeline would not have an adverse impact on Canadians. Instead, additional pipeline capacity would facilitate the operation of the market and could stimulate investment, including investment by participants seeking to develop domestic upgrading and refining facilities. Denying the Keystone Pipeline in order to restrict bitumen exports would constitute unwarranted regulatory intervention that would introduce uncertainty in the market that could negatively impact investment decisions and the availability of bitumen for both domestic and export markets. The NEB concluded that the market appeared to be functioning well, so there was no compelling reason for the NEB to interfere with the market by denying or delaying the Keystone Pipeline Project.[94]

5. DECISION GH-2-2006: *ENCANA CORPORATION DEEP PANUKE PIPELINE*[95]

The Deep Panuke Pipeline was approved by the NEB in September 2007. The purpose of the 176 km pipeline was to transport natural gas produced at EnCana Corporation's (EnCana) proposed Deep Panuke offshore processing unit, located 250 km southeast of Halifax, to a point near Goldboro, Nova Scotia. The pipeline and associated offshore processing unit were the subject of proceedings before the Canada-Nova Scotia Offshore Petroleum Board (the

89 *Ibid.*
90 *Ibid.*
91 *Ibid.*
92 17 December 1992, Can. T.S. 1994 No. 2, 32 I.L.M. 289 (entered into force 1 January 1994).
93 NEB Decision OH-1-2007, *supra* note 14 at 57.
94 *Ibid.*
95 *EnCana Corporation* (September 2007), NEB Decision GH-2-2006, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90464/90550/189912/441384/477267/477089/A1A3I9_-_Reasons_for_Decision,_GH-2-2006.pdf?nodeid=477090&vernum=0>.

CNSOPB). In conjunction with the CNSOPB process, and pursuant to s. 15 of the *NEB Act*, the NEB authorized one of its members to take evidence and gather information for the purpose of preparing a report and recommendations to the NEB respecting the pipeline project. The NEB subsequently adopted the authorized member's report and recommendations, approving the construction and operation of the pipeline under s. 52 of the *NEB Act* and determining that the EnCana would be treated as a Group 2 company for purposes of financial regulation of the pipeline.

In reaching his conclusions, the authorized member rejected arguments that EnCana should be required to use an existing offshore pipeline owned by Sable Offshore Energy Inc. (SOEI) originating at the Sable Offshore Energy Project. This alternative would only require the construction of approximately 15 km of new offshore pipeline. While EnCana stated that it was considering the SOEI option, EnCana's application was premised on the construction of the new pipeline. In addition, the owners of the SOEI pipeline expressed their support for the proposed pipeline. While the proposed Deep Panuke Pipeline would parallel the SOEI pipeline for much of its length and there appeared to be available capacity on the SOEI pipeline, the authorized member concluded that where there is an absence of major negative impacts that would outweigh the benefits from the Deep Panuke Pipeline, market forces should be allowed to prevail and EnCana should be able to make the final decision on the appropriate option.[96]

B. FEDERAL COURT

1. *MININGWATCH CANADA V. CANADA (MINISTER OF FISHERIES AND OCEANS)*[97]

In September 2007, the Federal Court granted a judicial review application made by MiningWatch Canada (MiningWatch) challenging the legality of decisions and actions taken by the Department of Fisheries and Oceans (DFO) and Natural Resources Canada (NRC) in conducting a federal environmental assessment under the *CEAA* of the proposed Red Chris Development Company Ltd. (Red Chris) open pit mining and milling operation for the production of copper and gold. In issuing its decision, the Court made a number of findings with respect to the duties of responsible authorities in relation to projects requiring environmental assessment under the comprehensive study process in the *CEAA*, particularly as they are affected by amendments to that process made in 2003 under *An Act to Amend the Canadian Environmental Assessment Act*.[98] The Court also addressed the impact of these legislative amendments on the decision of the Federal Court of Appeal in the *Prairie Acid Rain Coalition v. Canada (Minister of Fisheries and Oceans)*.[99]

The proposed Red Chris project was located in Northwestern British Columbia and fell under the regulatory jurisdiction of both the federal and provincial governments. A provincial

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96 *Ibid.* at 40.
97 2007 FC 955, [2008] 3 F.C. 84 [*MiningWatch*].
98 S.C. 2003, c. 9, amending S.C. 1992, c. 37 [Bill C-9].
99 2006 FCA 31, [2006] 3 F.C. 610 [*TrueNorth*].

environmental assessment was triggered under the British Columbia *Environmental Assessment Act*[100] and the *Reviewable Projects Regulation*.[101]

At the federal level, in response to an application from the proponent for authorizations under s. 35(2) of the *Fisheries Act*,[102] the DFO had determined that a federal environmental assessment under the *CEAA* had been triggered. The project also required a licence issued by the Minister of Natural Resources under the *Explosives Act*,[103] and an amendment by the Governor in Council of a regulation made under the *Fisheries Act*,[104] both of which were also *CEAA* environmental assessment triggers.

The description of the project in the proponent's *Fisheries Act* application included a mine and mill, as well as other ancillary components of the overall project, such as a tailings impound area and water intake facilities. The DFO's initial scoping of the project included, among other facilities, the mine and mill. The DFO made an initial determination that the proposed mill exceeded certain production rate thresholds under s. 16(c) of the *Comprehensive Study List Regulations*,[105] and as such, held that the project required a comprehensive study rather than an environmental screening under the *CEAA*. The DFO posted a notice of commencement of environmental assessment on the *CEAA* Registry, noting that an environmental assessment of the project was required under *CEAA*, and that the DFO would conduct a comprehensive study of the project.

A number of months later (and after a relatively complex series of events), the DFO re-scoped the project under s. 15 of the *CEAA* to exclude the mine and mill, purportedly based on the decision of the Federal Court of Appeal in *TrueNorth*. The DFO also determined that the project, as re-scoped, no longer required a comprehensive study under the *CEAA*, and instead, the DFO and NRC proceeded to complete an environmental screening only. The two federal bodies subsequently concluded that the project would not result in any significant adverse environmental effects in accordance with s. 20 of the *CEAA*.

Justice Martineau framed the issue before the Court as whether the responsible authorities (that is, DFO and NRC) could legally refuse to conduct a comprehensive study on the grounds that the project as re-scoped by them no longer included the mine and mill.[106]

On the basis of a number of the amendments to the *CEAA* implemented under Bill C-9 in 2003, most significantly the amendments to s. 21 of the *CEAA*, which deals with comprehensive studies, the Court held that the discretion to scope a project under s. 15 of the *CEAA* is not without limits, but responsible authorities are bound procedurally by the requirements of s. 21 of the *CEAA*, as amended in 2003.[107] The Court noted that where a project, as initially described by the proponent, is included in the *CSL Reg.* as requiring a

100 S.B.C. 2002, c. 43.
101 B.C. Reg. 370/2002.
102 R.S.C. 1985, c. F-14, s. 35(2).
103 R.S.C. 1985, c. E-17.
104 *Metal Mining Effluent Regulations*, S.O.R./2002-222.
105 S.O.R./1994-638 [*CSL Reg.*].
106 *Supra* note 97 at para. 273.
107 *Ibid.* at para. 291.

comprehensive study, the requirements of s. 21(1) of the *CEAA* are engaged, and a responsible authority has a legal duty to consult the public.[108] Section 21(1) requires that public consultation be undertaken "with respect to the proposed scope of the project for the purposes of the environmental assessment, the factors proposed to be considered in its assessment, the proposed scope of those factors and the ability of the comprehensive study to address issues relating to the project."[109] Once public consultation has been completed, the scoping exercise must set the parameters for the comprehensive study and provide a rationale for the design of the studies that may be required.[110]

In reaching these conclusions, the Court distinguished the Federal Court of Appeal's decision in *TrueNorth*, which was issued prior to the amendments to the *CEAA* under Bill C-9. In that case, the Court held, among other things, that a project would be subject to an environmental assessment under s. 5(1)(d) of the *CEAA* if the project was scoped by the responsible authority under s. 15(1) of the *CEAA*.[111] The Court also held that the mere fact that a work or activity (in that case, an oil sands undertaking) was included in the comprehensive study list did not require a responsible authority to include that work or activity within the scope of the project when exercising its scoping authority under s. 15(1) of the *CEAA*.[112]

Justice Martineau distinguished the *TrueNorth* decision on the following basis, concluding that *TrueNorth* does not apply to assessments commenced under the amended s. 21 of the *CEAA*:

> It is worthwhile to briefly highlight a few of the differences between the former and the amended versions of section 21 in order to emphasize why I am of the view that the *TrueNorth* decision is of limited applicability to the case at bar. Firstly, while the former section 21 of the CEAA did not make public consultation mandatory, the current version does. Furthermore, it is clear that the language of "proposed scope", as added to the new section 21, mandates that public consultation must take place prior to the actual scoping decision. Finally, under the new CEAA, once a "project" that has been proposed is set out in the CSL, the environmental assessment must be carried out by means of a comprehensive study.[113]

As a result of the *MiningWatch* decision, it appears that the question of whether a project that falls within the comprehensive study list will be subject to a comprehensive study versus a screening has relatively little to do with the responsible authority's powers to scope the project under s. 15 of the *CEAA*. Instead, it appears that the focus will be on the scope of the project as initially described to the responsible authority by the proponent, and perhaps to some extent, on the responsible authority's initial description of the project for tracking purposes. Proponents of projects requiring federal regulatory approvals that trigger the environmental assessment process under the *CEAA* should therefore consider carefully how they describe the scope of their projects to federal regulators. Further, if a project legitimately involves components that fall within the comprehensive study list, then under this decision,

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108 *Ibid.* at para. 302.
109 *Supra* note 27, s. 21(1).
110 *Supra* note 97 at para. 291.
111 *Supra* note 99 at para. 20.
112 *Ibid.* at 24; *supra* note 97 at para. 295.
113 *MiningWatch*, *ibid.* at para. 289.

it appears that a comprehensive study will be required, irrespective of whether the responsible authority scopes the project to exclude the component(s) included in the list.

The Minister of Fisheries and Oceans, the Minister of Natural Resources, the Attorney General of Canada, Red Chris Developments, and bcMetals Corporation (a wholly owned subsidiary of Imperial Metals Corporation) filed appeals of this decision on 24 October 2007. On 13 June 2008, the Federal Court of Appeal reversed Martineau J.'s decision.[114]

2. APPEAL OF *DENE THA' FIRST NATION V. CANADA (MINISTER OF ENVIRONMENT)*[115] — DENIED

On 16 January 2008, the Federal Court of Appeal dismissed Canada's appeal of the decision of the Federal Court in *Dene Tha' First Nation v. Canada (Minister of Environment)*.[116] In that decision, Phelan J. held in November 2006 that the Government of Canada failed in carrying out its basic constitutional duties by establishing the environmental and regulatory review process for the Mackenzie Gas Project without consulting the Dene Tha'.

3. *PEMBINA INSTITUTE FOR APPROPRIATE DEVELOPMENT V. CANADA (A.G.)*[117]

This case involved an application for judicial review by a number of non-governmental organizations respecting the report issued by the Joint Review Panel established under the *CEAA* by the Government of Canada and the AEUB concerning the environmental assessment of Imperial Oil Resources Ventures Limited's (Imperial) Kearl Lake Oil Sands Project. In its report issued in February 2007, the Joint Review Panel had recommended that the federal responsible authority, the DFO, approve the project, having reached the conclusion that provided the proposed mitigation measures and recommendations were implemented, the project was not likely to cause significant adverse environmental effects.[118]

The applicants for judicial review argued that the Panel failed to consider the factors enumerated in ss. 16(1) and 16(2) of the *CEAA* by (1) "relying on mitigation measures that were not technically and economically feasible" and (2) "failing to comply with the requirement to provide a rationale for its recommendations pursuant to s. 34(c)(i) of the *CEAA*."[119] The applicants focused their arguments on several topic areas in the Panel's report, including cumulative effects management and the Cumulative Effects Management Association, watershed management, landscape reclamation, endangered species, and GHG emissions.[120]

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114 *MiningWatch Canada v. Canada (Minister of Fisheries and Oceans)*, 2008 FCA 209, 379 N.R. 133.

115 2006 FC 1354, 303 F.T.R. 106.

116 2008 FCA 20, 35 C.E.L.R. (3d) 1.

117 2008 FC 302, 323 F.T.R. 297.

118 *Imperial Oil Resources Ventures Limited: Application for an Oil Sands Mine and Bitumen Processing Facility (Kearl Oil Sands Project) in the Fort McMurray Area* (27 February 2007), AEUB Decision 2007-013, online: ERCB <http://www.ercb.ca/docs/Documents/decisions/2007/2007-013.pdf>.

119 *Supra* note 117 at para. 35.

120 *Ibid.* at para. 30.

Justice Tremblay-Lamer held that the standard of review on the first error raised by the applicants was reasonableness *simpliciter*, stating that the applicants were, in essence, challenging the underlying completeness or quality of the evidence relied on by the Panel in reaching its conclusion. Whether or not the Panel provided a rationale for its conclusions and recommendations, however, was a question of law reviewable on a standard of correctness.[121]

Justice Tremblay-Lamer dismissed the application on all but one aspect of the Joint Review Panel's report, finding that the Panel had erred in law by failing to provide a reasoned basis for its conclusion that the mitigation measures proposed by Imperial would reduce the potentially adverse effects of the project's GHG emissions to a level of insignificance. The Panel's report identified the development of GHG emission intensity targets as the mitigation measure for adverse effects from GHGs and ultimately concluded that the project was not likely to result in significant adverse effects on air quality, provided the proposed mitigation measures were implemented. She stated:

> The evidence shows that intensity-based targets place limits on the amount of greenhouse gas emissions per barrel of bitumen produced. The absolute amount of greenhouse gas pollution from oil sands development will continue to rise under intensity-based targets because of the planned increase in total production of bitumen. The Panel dismissed as insignificant the greenhouse gas emissions without any rationale as to why the intensity-based mitigation would be effective to reduce the greenhouse gas emissions, equivalent to 800,000 passenger vehicles, to a level of insignificance. Without this vital link, the clear and cogent articulation of the reasons behind the Panel's conclusion, the deference accorded to its expertise is not triggered.
>
> While I agree that the Panel is not required to comment specifically on each and every detail of the Project, given the amount of greenhouse gases that will be emitted to the atmosphere and given the evidence presented that the intensity based targets will not address the problem of greenhouse gas emissions, it was incumbent upon the Panel to provide a justification for its recommendation on this particular issue. By its silence, the Panel short circuits the two step decision making process envisioned by the CEAA which calls for an *informed decision* by a responsible authority. For the decision to be informed it must be nourished by a robust understanding of Project effects. Accordingly, given the absence of an explanation or rationale, I am of the view that the Panel erred in law by failing to provide reasoned basis for its conclusion as mandated by s. 34(c)(i) of the CEAA.[122]

Justice Tremblay-Lamer also determined that it was not necessary that the Panel conduct its review of the project a second time. The matter was remitted back to the Panel "to provide a rationale for its conclusion that the proposed mitigation measures [would] reduce the potentially adverse effects of the Project's greenhouse gas emissions to a level of insignificance."[123]

An application by Imperial to be allowed to proceed with the project was dismissed by the Federal Court of Appeal on 14 May 2008.[124]

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121 *Ibid.* at paras. 40-41.
122 *Ibid.* at paras. 78-79 [emphasis in original].
123 *Ibid.* at para. 80.
124 *Imperial Oil Resources Ventures Ltd. v. Canada (Minister of Fisheries and Oceans)*, 2008 FC 598, 36 C.E.L.R. (3d) 153.

C. ALBERTA ENERGY AND UTILITIES BOARD

A substantial number of energy applications filed with the AEUB are resolved without a hearing as a result of effective public consultation and appropriate dispute resolution (ADR). Some applications could not be resolved in 2007-2008, including company-to-company production disputes and various sour gas and upgrader developments. A number of decisions also address the need for the regulator to be impartial and free of an apprehension of bias.

1. DECISION 2007-043: *REAL RESOURCES INC.: SECTION 40 REVIEW REQUEST OF FACILITY LICENCE NO. F36914, SAKWATAMAU FIELD*[125]

Proper notification of an application is critical, including notification of other affected industry participants. Any person affected by an order made without the holding of a hearing may, within 30 days after the date of order, apply to the ERCB for a hearing. The ERCB's Directive 056[126] requires an applicant to identify and contact all oil and gas reserve owners and licensees of existing similar facilities within its recommended radius. "It is the applicant's responsibility to determine if the recommended radius of notification needs to be expanded for the proposed development."[127]

The AEUB had granted a review of the licence on the grounds that Canetic Resources Inc. (Canetic) had a mineral interest in the reserves that would be processed at the battery and was therefore affected. The AEUB accepted that Canetic had the right to request a review of the facility licence under s. 40 of the *Energy Resources Conservation Act*.[128] However, after the Board gave notice that it would hold a review hearing, the parties participated in an ADR process and the request for a review was ultimately withdrawn. On 29 May 2007, the AEUB cancelled the public hearing scheduled to review the facility licence.

2. DECISION 2007-047: *CANADIAN NATURAL RESOURCES LIMITED: APPLICATION FOR COMPULSORY POOLING, BELLIS FIELD*[129]

The AEUB may order compulsory pooling under s. 80 of the *Oil and Gas Conservation Act*[130] if an agreement to operate as a unit cannot be made under reasonable terms. The most common dispute is the allocation of each company's share of the production of oil and gas. The default outcome is allocation on a tract (area) basis unless it can be shown this allocation is inequitable.[131] In this case, the parties could not agree on the allocation in Bellis Field, and examiners were appointed to evaluate the technical evidence presented by the parties on equitable allocation.

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125 (29 May 2007), AEUB Decision 2007-043, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-043.pdf>.

126 ERCB, Directive 056, "Energy Development Applications and Schedules" (14 July 2008), online: ERCB <http://www.ercb.ca/docs/Documents/directives/ Directive056.pdf> [ERCB Directive 056].

127 *Ibid.*, s. 2.3.2.

128 R.S.A. 2000, c. E-10, s. 40 [*ERCA*].

129 (12 June 2007), AEUB Decision 2007-047, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-047.pdf>.

130 R.S.A. 2000, c. O-6, ss. 80(1), 80(2)(c) [*OGCA*].

131 *Ibid.*, s. 80(4)(c).

The AEUB examiners recommended a compulsory pooling order be issued for lands in Bellis Field, allocating costs on a tract basis, with a penalty provision of 200 percent to be applied and designating Canadian Natural Resources Limited (CNRL) as the operator of the well.[132]

CNRL had an 88.281 percent interest on a tract basis in the gas rights for all zones to the base of the Wabamun formation and had attempted to form a pooling agreement with the other interest holder, Bowood Energy Corp. (Bowood). However, these negotiations failed, and CNRL submitted an application for a compulsory pooling order. Bowood opposed CNRL's application as it felt that the issues could be resolved without a pooling order and that it would be inequitable to pool interests on a tract area basis. Bowood claimed that the forced pooling would dilute Bowood's interest in the western portion of the lands in question by including CNRL's tract on the east half which Bowood considered to be unproductive. Bowood suggested that the lands be split into east and west halves and the cost allocation be based on tract area within each separate half.[133]

The examiners held that a pooling order was required in this case due to the inability of the two parties to reach a voluntary pooling agreement. The examiners stated that the reserves-based allocation proposed by Bowood required "clear and convincing evidence to show that it would be inequitable to allocate otherwise."[134] Because sufficient evidence was not provided and given the geological complexity of the land in question, the examiners concluded that pooling on a tract area basis would be appropriate and equitable and approved CNRL's application.[135]

3. DECISION 2007-053: *SHELL CANADA LIMITED: PREHEARING MEETING, APPLICATIONS FOR A WELL AND ASSOCIATED PIPELINE LICENCES, WATERTON FIELD*[136]

In the case of controversial hearings involving many potential interveners, a prehearing meeting is an effective way to determine the rights of parties to participate in the hearing and limit the scope of issues to be determined at the hearing.

On 29 June 2007, the AEUB released its Prehearing Meeting Report regarding Shell Canada Limited's (Shell) application for a licence to drill a level-3 critical sour gas well from a surface location 5.8 km southwest of Beaver Mines, Alberta, and for approval to construct and operate associated pipelines to the well.[137]

In making its determination of standing pursuant to s. 26 of the *ERCA*, the AEUB applied a two-part test: (1) the legal question of whether a person has a legally recognizable interest or right and (2) the factual question of whether the application directly or adversely affects

132 *Supra* note 129 at 3.
133 *Ibid.* at 6.
134 *Ibid.* at 8.
135 *Ibid.*
136 (29 June 2007), AEUB Decision 2007-053, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-053.pdf>.
137 *Ibid.* at 1.

that interest or right.[138] The Board was satisfied that anyone living within Shell's proposed 6.9 km emergency planning zone (EPZ) would be a person who meets both parts of the test and would have standing to participate at the hearing.[139]

The AEUB also considered a notice of constitutional question from Calgary-based Michael Sawyer who was a recreational user of the public lands within the EPZ and private lands adjacent to the proposed well. He claimed that the sour gas risk was a threat to his right to life, liberty, and security of the person under s. 7 of the *Canadian Charter of Rights and Freedoms*.[140] In applying the two-part test to Sawyer, the AEUB accepted the argument that a right may arise regarding the protection of an individual's health and safety. However, Sawyer did not meet the second part of the test as he had not demonstrated the connection between the proposed well and pipeline and any potential direct and adverse impact to his and his family's health or safety.[141] Moreover, because they were recreational users, they would only be subject to potential direct and adverse impacts if they *chose* to frequent the area; the potential impacts were no greater than those to any member of the general public visiting the area. The AEUB also cited several cases that determined that "'directly affected' referred to a personal and individual interest as opposed to a general interest that pertained to the community as a whole."[142] Thus, the AEUB determined that Sawyer did not have standing. Therefore, the AEUB held that the constitutional question would not be addressed.[143]

The AEUB also dismissed the Castle Crown Wilderness Coalition's (CCWC) request for standing. The CCWC claimed an interest in the ecologically important public land involved in the proposed project. However, the AEUB held that CCWC did not advance a legal right or interest in land or any potential direct or adverse impact and dismissed the application.[144]

The AEUB also made determinations on the scope of the hearing. It limited the hearing issues to the applications and the impacts of the proposed well and pipelines and planned development in proximity to this development. The AEUB dismissed submissions that the scope should be broader and include "provincial land-use policy and the impacts of current developments and future development in the area involving oil and gas, forestry, agriculture, and recreation."[145] The AEUB also rejected the consideration of the integrity of the interconnected sour gas pipeline system and limited discussion to the integrity of the short (1 km) pipeline for which approval was sought.[146]

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138 *Ibid.* at 3.

139 *Ibid.*

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

141 *Supra* note 136 at 5.

142 *Ibid.*

143 See *Sawyer v. Alberta (Energy and Utilities Board),* 2007 ABCA 297, 422 A.R. 107. The AEUB's decision on standing was upheld on the basis that leave to appeal would not be granted on a question of mixed fact and law.

144 *Supra* note 136 at 5.

145 *Ibid.* at 6.

146 *Ibid.*

The AEUB determined that the following issues were within scope: "need for the wells and pipelines; location of the well and pipelines; human health and safety; emergency response planning; future area development and cumulative impacts; visual and other environmental impacts …; [and] property values."[147]

A six-day public hearing was held in Pincher Creek, Alberta, in late September to early October 2007. However, on 19 November 2007, after the evidentiary phase of the public hearing was completed, but before a decision was issued on the merits of the well licence application, a rupture occurred on Shell's interconnected sour gas pipeline, which resulted in the evacuation of several families within the EPZ. After consulting with local residents, the AEUB decided to hold the well licence decision in abeyance, pending an investigation of the pipeline rupture. As of 1 May 2008, no decision on the well licence had been issued.

4. DECISION 2007-058: *NORTH WEST UPGRADING INC.: APPLICATION TO CONSTRUCT AND OPERATE AN OIL SANDS UPGRADER IN STURGEON COUNTY*[148]

Applicants for major facility approvals must carry out an extensive public consultation program, which exceeds the minimum standards set out in ERCB Directive 056. In these situations, the AEUB must navigate through the authority of other agencies with jurisdiction, including municipalities, Alberta Environment, and Environment Canada.

In this decision, the AEUB gave conditional approval to North West Upgrading Inc.'s (North West) oil sands upgrader near Edmonton, Alberta. The conditions placed on the approval were that: (1) the project achieve a sulphur recovery of 99.5 percent every calendar quarter; (2) the project achieve its approved sulphur recovery beginning six months after start-up; and (3) the proponent submit a revised noise impact assessment for review and approval by 3 March 2008.[149]

Need for the upgrader was not opposed and the AEUB held that "need" was supported by Alberta's strategy for value added resource development.[150] The focus of the hearing was therefore on the following issues.

a. Public Consultation

The AEUB ruled that ERCB Directive 056 public consultation requirements are the bare minimum for upgrader projects. The AEUB found North West's public consultation program, which featured two open houses and personal contact with the residents within 5 km, was a legitimate and well-intentioned effort to engage affected parties. However, the AEUB put future applicants on notice that the public should be given more opportunities to ask questions, for example, through additional open houses.[151]

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147 *Ibid.* at 7.

148 (7 August 2007), AEUB Decision 2007-058, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-058.pdf>.

149 *Ibid.*, Appendix 3.

150 *Ibid.* at 4.

151 *Ibid.* at 8.

b. Socio-economic Effects

Even though the AEUB found that additional government investment in infrastructure would be needed, it also found that the overall benefits of the project would be significant for the region, province, and country.[152] The AEUB declined the City of Edmonton's proposal for a condition requiring North West to participate in regional planning with municipalities.[153] The AEUB also declined to rule on the voluntary property purchase program (VPPP), although VPPP managers were encouraged to be flexible in administering this program.[154]

c. Site Selection

The proposed location within the river valley of Edmonton's metropolitan area was found to be appropriate and fully compatible with the intended land use of the proposed project site. The AEUB relied on zoning approvals and support from municipalities.[155]

d. Setbacks

The AEUB found that setbacks were within the jurisdiction of the County and expected that the project would meet all municipal requirements, including setbacks.[156]

e. Emergency Response Planning

The AEUB found that North West had filed the appropriate emergency response information. The AEUB required the applicant to develop a site-specific emergency response plan to address residents' concerns with regard to the notification of people working outside the home during an emergency.[157]

f. Air Quality

North West's modelling approach was found to be appropriate and conducted in accordance with Alberta Environment's *Air Quality Model Guideline*.[158] The AEUB noted that Alberta Environment is the responsible authority to determine whether North West is using the appropriate technology to control air emissions and that North West should be proactive in using appropriate technology and taking into account reasonably foreseeable changes to emission guidelines.[159]

The AEUB also recognized the importance of ensuring that there is confidence in air quality monitoring. Environment Canada's recommendations on leak detection and repair

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152 *Ibid.* at 9.
153 *Ibid.* at 11-12.
154 *Ibid.* at 14.
155 *Ibid.* at 15-16.
156 *Ibid.* at 16.
157 *Ibid.* at 19.
158 (March 2003), online: Alberta Environment (AE) <http://environment.gov.ab.ca/info/library/6709.pdf>.
159 *Supra* note 148 at 23.

were commended to Alberta Environment as the responsible authority. The AEUB accepted North West's commitments to purchase ozone-monitoring equipment and to improve the regional monitoring network.[160]

The AEUB also found that the flare systems were an integral and necessary part of the process and safety systems of the upgrader. The AEUB accepted North West's commitment to design its flare system to meet the AEUB's requirements and to minimize flaring under all circumstances.[161]

g. Health

The AEUB concluded that the predicted health risks of the project were insignificant and the cancer risk of the project should be assessed on an incremental basis.[162]

h. Water

The AEUB accepted North West's proposed efforts to decrease water withdrawal from the North Saskatchewan River as well as its discharge and disposal volumes. The AEUB supported North West's proposal to use grey water effluent from the City of Edmonton, even though the possible improvement in water quality had not been quantified. The AEUB also accepted North West's efforts to deal with surface water drainage and to monitor ground water resources in the area.[163]

i. Sulphur Technology

During the public hearing, North West had volunteered to increase its sulphur recovery to 99.2 percent from 99.1 percent with the addition of a specific catalyst to the process.[164] The AUEB noted the importance of sulphur recovery being regulated on a regional basis. Therefore, while there would be technical, cost, and operational impacts in requiring North West to move to a higher recovery bracket, the AEUB found that it was in the broad public interest to preserve the airshed capacity in the region and to require North West to achieve a minimum calendar quarter-year sulphur recovery of 99.5 percent within six months of the project's start-up.[165]

The AEUB also found that gasification technology was appropriate for the production of hydrogen and that it produced a pure carbon dioxide (CO_2) stream that would allow for easy capture and future use. The technology also substantially cut the need for natural gas.[166]

160 *Ibid.* at 25.
161 *Ibid.* at 26.
162 *Ibid.* at 28.
163 *Ibid.* at 29-30.
164 *Ibid.* at 33.
165 *Ibid.* at 34-35.
166 *Ibid.* at 37.

j. Noise

The AEUB determined that a mobile home near the project could be considered a seasonally occupied dwelling, and as a result, the AEUB conditioned the approval on a revised noise impact assessment to be submitted for review and approval by 3 March 2008.[167]

5. DECISION 2007-083: *DECISION TO ISSUE A DECLARATION NAMING DAVID N. MATHESON AND RONALD P. BOURGEOIS PURSUANT TO SECTION 106 OF THE OIL AND GAS CONSERVATION ACT*[168]

Restructuring the financial affairs of oil and gas companies in default of well abandonment obligations can expose officers and directors to a s. 106 declaration.

M.L. Cass Petroleum Corporation (M.L. Cass) was a junior oil and gas company that fell upon tough times in the 1990s. The company lacked the financial resources to abandon its wells. In 2000, the AEUB issued abandonment orders, which ultimately resulted in unpaid debts of more than $1 million to the AEUB and the Orphan Well Association (OWA). The AEUB's Corporate Compliance Group (CCG) decided to go after two of the directors and officers of M.L. Cass under s. 106 of the *OGCA*.[169] This section allows the AEUB to issue a "declaration" naming persons in control of corporate licence holders who have outstanding debts to the AEUB or the OWA. The effect of the declaration is to disqualify any company directly or indirectly controlled by a named individual from holding approvals and filing applications on a routine basis with the AEUB.

After the abandonment orders were issued against M.L. Cass, two former directors of M.L. Cass (one of whom had been out of Canada and had severed ties with M.L. Cass during the time the abandonment orders were first issued) accepted reappointment to the Board of Directors of M.L. Cass in order to advance a financial restructuring of the company. However, as events developed, these individuals were unable to reach a settlement with M.L. Cass' major creditor, the CCG on behalf of the AEUB/OWA, in a manner that would allow the company to be restructured. It was also the CCG that ultimately recommended pursuing a declaration pursuant to s. 106 of the *OGCA*, which the AEUB did issue against these two directors. The AEUB then convened a "show cause" hearing to determine the procedural rights that should be accorded to the individuals and whether the key elements of s. 106 of the *OGCA* dealing with control in fact and the public interest in issuing a declaration had been established.

The AEUB's decision found that the separation of the Declaration Panel from the AEUB panel that had issued the intention to issue a declaration and the walling off of CCG from *ex parte* contact with the Declaration Panel allowed a fair process to be accorded the individuals with respect to the principles of natural justice.[170] Further, the AEUB held that the *Charter* did not infringe the right of the individuals to join an association in pursuit of a common goal

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167 *Ibid.*

168 (6 November 2007), AEUB Decision 2007-083, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-083.pdf> [AEUB Decision 2007-083].

169 *Supra* note 130.

170 *Supra* note 168 at 9.

under s. 2 of the *Charter*.[171] The AEUB also ruled that s. 106 is neither an offence provision nor a penal one with respect to the individuals. The Declaration Panel reasoned that ss. 107 to 110 of the *OGCA* establish separate provisions for offences and penalties and "Section 106 of the *OGCA* is [more] akin to a disqualification proceeding, where disqualifications are imposed as part of a scheme regulating an activity in order to protect the public [such as securities regulation], which are not the sort of 'offence' proceedings to which Section 11 of the *Charter*"[172] is applicable.

The AEUB then turned to elements of s. 106, which includes "control" over the defaulting company and the "public interest" in issuing a declaration. On the element of "control," the Declaration Panel restated the following test from AEUB Decision 2000-51:

> *Control is ultimately the power to direct the business of a company and make decisions that will be complied with and acted upon by the company*. Each case must be reviewed on its own facts and circumstances in order to determine the entity effectively exercising this authority.[173]

However, the Declaration Panel ruled that the onus was on the individual to establish that they were *not* indirectly or directly involved in the control of M.L. Cass.[174] Even though one of the individuals was not a resident of Canada during relevant times, evidence of informal discussions while he was out of the country and without position at M.L. Cass was sufficient for the Declaration Panel to find that the "control" component of the test was met.[175]

On the element of "public interest," the individuals argued that they had made efforts to restructure the affairs of M.L. Cass in a way that would see the AEUB and OWA compensated for the abandonment costs following a successful financial restructuring. However, the AEUB held that continuing confidence of the public in the AEUB's regulatory scheme for oil and gas was best assured by preventing a licensee or person in control of a licensee from continuing to breach abandonment orders.[176] In the result, the AEUB issued a declaration pursuant s. 106 of the *OGCA* with an indefinite term, adding that convincing evidence must be presented to warrant a declaration for only a finite period.

6. DECISION 2007-090: *BEARSPAW PETROLEUM LIMITED: COMPLAINT RESPECTING EUB ENFORCEMENT ACTIONS AND ALLEGATION OF BIAS AGAINST THE EUB RED DEER FIELD CENTRE*[177]

Bearspaw Petroleum Limited (Bearspaw) alleged that the AEUB's Red Deer Field Office and the Red Deer Field Office's team leader were biased against it.

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171 *Ibid.* at 10.

172 *Ibid.* at 11.

173 *Ibid.* at 19, quoting *South Alberta Energy Corp., Greg Justice, 693040 Alberta Ltd., and Marc Dame Review of Abandonment Costs Order No. ACO 98-1* (17 July 2000), AEUB Decision 2000-51, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2000/2000-51.pdf> at 11 [emphasis added].

174 AEUB Decision 2007-083, *ibid.* at 19.

175 *Ibid.* at 20-21.

176 *Ibid.* at 24.

177 (6 November 2007), AEUB Decision 2007-090, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-090.pdf>.

Former Alberta Ethics Commissioner R.C. Clark was appointed as an acting Board member to investigate and report on these allegations. He found that the evidence did not support a finding of bias or the reasonable apprehension of bias. Clark held that there were reasonable grounds to support the actions taken by the AEUB in each of the incidents alleged to be biased and that in all but the Big Valley odour incident, a prudent decision was made in the circumstances.

Bearspaw's claims stemmed from five key enforcement incidents under ERCB's Directive 019[178] as well as several minor incidents associated with Bearspaw's facilities and operations. These incidents included:

- *The Big Valley Odour Incident:* an alleged leak of hydrogen sulphide (H_2S). Subsequent investigation resulted in a high-risk non-compliance enforcement action being issued against Bearspaw, which was ultimately shown to be unjustified.[179]

- *High Level Trucking Incident*: the inspection of a Bearspaw contracted tanker truck as a result of a complaint of a H_2S odour being reported. This resulted in a high-risk non-compliance enforcement action being levied against Bearspaw, which was later withdrawn.[180]

- *The Flame Arrester Incident*: an inspection of a Bearspaw facility that resulted in the issuance of a high-risk non-compliance enforcement action due to missing parts associated with a flame arrester unit.[181]

- *The 6-26 Odour Incident*: a small volume H_2S leak that Bearspaw did not dispute, which resulted in enforcement against Bearspaw. Bearspaw alleged that enforcement for such a small volume release detectable on lease only through the use of state of the art air monitoring units by the AEUB was unfair.[182]

- *The Pipeline Incident*: After a farmer struck a Bearspaw pipeline that had been installed in 1950, Bearspaw was asked to conduct a depth of cover survey for all lines of similar age. Bearspaw stated that it felt bullied in the process.[183]

While generally upholding the actions of the AEUB, Clark also made the following recommendations to enhance the fairness and transparency of the AEUB's inspection and enforcement process:

- Develop a written policy on disclosure of inspection/investigation results and enforcement information including timelines for such disclosure.

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178 ERCB, Directive 019, "ERCB Compliance Assurance — Enforcement" (20 February 2007), online: ERCB <http://www.ercb.ca/docs/documents/directives/Directive019.pdf> [ERCB Directive 019].

179 *Supra* note 177 at 5-7.

180 *Ibid.* at 7-8.

181 *Ibid.* at 8-9.

182 *Ibid.* at 10-11.

183 *Ibid.* at 11.

- Review the AEUB's jurisdiction over odours emanating from oil field trucks and provide a written clarification to industry of its policy.

- Host a one-day program to provide information to licensees on inspection and enforcement processes at each of its field centres.

- Implement changes to its Field Inspection System to identify appropriate status when enforcement actions are changed, withdrawn, or rescinded and to provide notification to the licensees of entries into the reporting system.[184]

Clark found that the Big Valley Odour incident presented inconclusive facts to justify a non-compliance action. However, in each of the other incidents noted above, Clark stressed the AEUB's duty to protect the public interest and that Bearspaw would have recourse to the appeal provisions in ERCB Directive 019.[185] The Board's inspection and enforcement processes were generally upheld as procedurally fair.

7. DECISION 2007-108: *DUVERNAY OIL CORP. AND MURPHY OIL COMPANY LTD.: APPLICATIONS FOR THE PRODUCTION AND SHUT-IN OF GAS FROM THE SEAL BLUESKY A POOL, PEACE RIVER OIL SANDS AREA*[186]

This decision is one of the latest in the "gas over bitumen" debate and involved applications by Murphy Oil Company Ltd. (Murphy) and Duvernay Oil Corp. (Duvernay) in relation to production from the Bluesky Formation (Bluesky). The AEUB denied Murphy's application to shut-in gas production from the Bluesky and granted Duvernay's application to produce Bluesky gas.

Murphy asked to shut-in gas production because it was concerned that increased gas production in the A Pool of Bluesky would remove the primary drive mechanism for bitumen recovery.[187]

The AEUB distinguished its approval of an extended 2 km region of influence (ROI) in AEUB Decision 2007-056[188] on the basis that the A Pool pressure data did not suggest the presence of an interconnected sand system over an extended area. The AEUB also found that the bitumen resources within the ROI of the A Pool would be very difficult if not impossible to produce, especially taking into account reasonably foreseeable technology and economic conditions. Therefore, the AEUB accepted Duvernay's view that there was a low probability that the bitumen within the ROI was potentially recoverable and concluded that gas production from the A Pool should be allowed.[189]

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184 *Ibid.* at 3.

185 *Ibid.* at 21.

186 (18 December 2007), AEUB Decision 2007-108, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-108.pdf>.

187 *Ibid.* at 2.

188 *Fisher and Moore Fields, Cold Lake Oil Sands Area: Applications for theProduction and Shut-in of Gas from the Clearwater Formation* (24 July 2007), AEUB Decision 2007-056, online: ERCB <http://www.ercb.ca/docs/documents/decisions/2007/2007-056.pdf>.

189 *Supra* note 186 at 18-19.

The AEUB did indicate, however, that given the limited data and uncertainty regarding the ROI of the A Pool and the potential recoverability of the bitumen, there might be a need to reassess the appropriateness of the gas production if new data became available, including more and better pressure data. Duvernay was ordered to file annual pressure reports and Murphy was encouraged to collect further pressure data.[190]

Finally, the AEUB held that there was a need for an assessment of whether gas production occurring in the main bitumen trends throughout the Peace River Oil Sands Area should be curtailed and that a specific assessment process would be determined at a later date.

8. DECISION 2007-111: *DUVERNAY OIL CORP.: APPLICATIONS FOR WELL, BATTERY, AND PIPELINE LICENCES, EDSON FIELD*[191]

Safety is the major issue in sour gas developments. The AEUB frequently imposes conditions on its approvals, which the applicant must satisfy to avoid being found in breach of its approval and subject to enforcement under ERCB Directive 019. Applicants often find it advisable to make commitments, which the AEUB takes into account in making its decisions. The AEUB expects that the applicant will follow through with its commitments, failing which the AEUB on its own motion or on application of an affected party may seek review of the original approval.

On 20 December 2007, the AEUB approved Duvernay's applications for a critical sour well, a battery, and pipeline licences. The AEUB found these applications to be in the public interest and that when all commitments and conditions were met, the well could be safely drilled and the battery and pipeline safely operated while still providing the necessary level of protection for the public and the environment.

There were several interventions to these applications. While most intervening parties lived within the EPZ and were granted full intervener status, two individuals who lived outside the EPZ were considered to be directly and adversely impacted, and were provided an opportunity to present their concerns. The following issues were dealt with at the hearing.

a. Need For and Location of the Well, Battery, and Pipeline

While not commenting on the specific location of the well, battery, and pipeline, interveners took the position that no critical sour gas wells, especially of the intensity proposed in the application, should be drilled in such close proximity to residences, farms, and ranches, especially with no benefit to these groups or the local community. The AEUB found that it was satisfied that the existing wellbore at the site would be appropriate for accessing the resource. The AEUB was also satisfied that the exploitation of these resources

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190 *Ibid.* at 19.

191 (20 December 2007), AEUB Decision 2007-111, online: ERCB <http://www.ercb.ca/docs/Documents/decisions/2007/2007-111.pdf>.

was in the public interest and that the project could be operated in a manner that ensured the protection of the public and the environment.[192]

b. Project Operations

The AEUB found that the nature of the intended sour reservoir was an important factor to be considered. Based on the detailed information on the geology of the area, the evidence presented regarding the well presently in place and the intended well drilling and operating procedures, the AEUB held that it would be unlikely that abnormal pressure would be experienced and that the risk of an uncontrolled release of gas during drilling would be significantly reduced. The AEUB also agreed that the likelihood of a release during drilling was low given the stringent requirements in place for critical sour wells. Given the sufficient resources and expertise of Duvernay, the AEUB was satisfied that Duvernay could safely carry out the project.[193]

c. Emergency Planning Zone Sizes

Duvernay submitted that it had considered that all of the AEUB's emergency response requirements had been met and it had calculated the EPZ using the AEUB's nomograph method. While the interveners acknowledged that Duvernay's calculations were correct, they argued that the new *ERCH$_2$S Model*[194] would be more accurate and should be applied. The AEUB held that the nomograph method was sufficient in this case to calculate the initial EPZ and that using what the AEUB found to be the appropriate ignition time for drilling operations of 15 minutes, the EPZ was actually 2 km larger when the nomograph method was used. Moreover, Duvernay was required to confirm the EPZ using data provided after the well's completion.[195]

d. Drilling Completion and Production Emergency Response Procedures

The AEUB emphasized that Duvernay's emergency response procedures (ERP) must be complete and updated prior to the commencement of drilling or production operations.[196] While the AEUB accepted that a 15 minute ignition time during the drilling phase was reasonable and achievable as the well would be continuously manned during this time, Duvernay will be required to demonstrate, prior to entering the sour zone, its ability to ignite within that time frame.[197] Moreover, given concerns regarding the ability of Duvernay's operators to reach the site within 60 minutes when it was unmanned during the production operation phase, the approval was conditioned on Duvernay conducting a verification of its stated response times. [198]

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192 *Ibid.* at 4.

193 *Ibid.* at 6-7.

194 ERCB, *ERCBH$_2$S: A Model for Calculating Emergency Response and Planning Zones for Sour Gas Facilities* (Calgary: Energy Resources Conservation Board, 2008), online: ERCB <http://www.ercb.ca/docs/public/sourgas/EUBModelsDraft/Volume1_ERCBTechnicalReference_200807.pdf>.

195 *Supra* note 191 at 12-13.

196 *Ibid.* at 18.

197 *Ibid.*

198 *Ibid.* at 19.

e. Training, Exercise, and Response Personnel

The combination of Duvernay's commitments to conduct full-scale training in addition to the training exercises already completed exceeded the requirements set out in ERCB Directive 071.[199] The AEUB did instruct Duvernay to complete the required training and to provide the interveners with a report detailing the results and any issues arising. Furthermore, because Duvernay could not advise the AEUB of whether it or Talisman Energy Inc. would be operating the well, the AEUB expected that the company personnel actually performing the day-to-day operations would also be tested in the exercises.[200]

f. Flaring, Incineration, and Dispersion Modelling

The AEUB accepted Duvernay's commitments in relation to H_2S, sulphur dioxide, and nitrogen oxide emissions by conducting air dispersion modelling under five operation and emergency situations. As a condition to receiving its licence, Duvernay was required to perform a survey of the proposed incineration stack to ensure that the actual exhaust parameters conformed to the parameters used in its modelling, and if any results differ, "to take the necessary measures to ensure that the Alberta Ambient Air Quality Objectives [were] met for the proposed incinerator."[201]

g. Compliance Issues

While Duvernay had two high-risk non-compliance events associated with drilling sour wells in Alberta, the AEUB noted that Duvernay also took significant steps to prevent reoccurrence and to improve its operations. These responses demonstrated a commitment to ensuring the protection of the public and the environment, and the AEUB was of the view that Duvernay's application should not be denied as a result of its compliance record.[202]

h. Public Consultation and Other Matters

Building confidence and relationships is a key factor in the consultation process, and the AEUB encouraged Duvernay to continue its efforts to find ways to communicate and build trust with the interveners and the community.[203]

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199 ERCB, Directive 071, "Emergency Preparedness and Response Requirements for the Petroleum Industry" (18 November 2008), online: ERCB <http://www.ercb.ca/docs/Documents/directives/Directive071.pdf> [ERCB Directive 071].

200 *Supra* note 191 at 24-25.

201 *Ibid.* at 29-30.

202 *Ibid.* at 31.

203 *Ibid.* at 33.

9. DECISION 2008-018: *HIGHPINE OIL & GAS LIMITED: APPLICATIONS FOR WELL LICENCES, PEMBINA FIELD*[204]

In some sour gas cases, applicants and interveners submit fatality risk assessments, although this is not required by the Directives. Constitutional points are also increasingly being raised. Where a constitutional question is raised, the Attorney General of Alberta often participates in the hearing.

In this decision, the AEUB approved Highpine Oil & Gas Limited's (Highpine) applications for licences to drill two level-2 critical sour wells near Drayton Valley, Alberta. The applications were approved on the basis of certain commitments made by Highpine:

- Highpine will not flare more than eight hours in total for each well.
- Highpine will maintain roads in the EPZs to ensure that they remain passable during critical sour operations.
- Highpine will suspend operations if any roads inside the EPZs are unable to be made passable.
- Highpine will lead one full-scale emergency response exercise every year.
- Highpine will update its ERPs, including updating all resident information, and submit those updates to the EUB for review.
- Highpine will ignite an uncontrolled release within 15 minutes of sour gas reaching surface.[205]

The AEUB addressed the following issues raised during the hearing.

a. Need for the Wells

The AEUB accepted Highpine's development plan and found, in balancing the rights of the mineral owners and surface rights holders and in considering the economic benefit to be gained from the wells, that there was a need for the wells.[206]

b. Location of the Wells

The AEUB accepted Highpine's explanation of the geological setting necessitating these locations. In light of the fact that the interveners did not suggest any alternatives and that Highpine had tried to minimize its footprint by abutting an existing well site, the AEUB approved Highpine's location.[207]

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204 (6 March 2008), AEUB Decision 2008-018, online: ERCB <http://www.ercb.ca/docs/Documents/decisions/2008/2008-018.pdf>.

205 *Ibid.* at 33.

206 *Ibid.* at 4.

207 *Ibid.* at 6.

c. Public Consultation

Given its two open houses and ongoing communication with affected parties, the Board was satisfied that Highpine had met its public consultation requirements as intended by ERCB Directive 056.[208]

d. Safety and Risk (Well Design, Hazard, Risk, and Emergency Response Planning)

In addition to various dispersion and well test flaring models, Highpine submitted fatality assessments. These included a comparison of its risk assessment to the fatality criteria of the Major Industrial Accident Council of Canada (MIACC), assessing societal risk from an uncontrolled release of H_2S. The interveners objected to Highpine's interpretation of its risk assessment tools, stating that the risk was underestimated because certain hazards (such as radiant heat and over pressure) were not addressed. The AEUB noted that "hazard and risk assessments and modelling of emergency releases are not currently required but are useful in some cases to have a full understanding of the potential impacts from emergency situations and associated risks."[209]

The AEUB also stated that, in spite of the risk assessments done by Highpine, neither Highpine nor the interveners provided adequate evidence to support their claims for the appropriate threshold of societal risk.[210] The AEUB did accept Highpine's comparison of the level of individual risk to the MIACC fatality criteria. On the basis that Highpine had minimized the risks to the public, had considered all relevant actions, and had implemented the AEUB's additional safety requirements for drilling critical sour gas wells, the AEUB determined that the hazards and risks would be adequately managed.[211]

e. Compliance History

In spite of past high-risk enforcement incidents, the AEUB felt that Highpine had taken actions to improve its processes and did not consider "Highpine's compliance record … a factor that would cause the Board to deny the applications."[212]

f. Traffic, Noise, and Environment

The AEUB accepted that Highpine had taken appropriate measures to mitigate the short-term increase in noise (an extended muffler system placed underground), and to protect the ground water by cementing the casings. Highpine also acknowledged the short-term increase in traffic the residents would experience.[213]

208 *Ibid.* at 8.
209 *Ibid.* at 13.
210 *Ibid.*
211 *Ibid.* at 14.
212 *Ibid.* at 20.
213 *Ibid.* at 21.

g. *Canadian Charter of Rights and Freedoms*

The interveners argued that their rights to fundamental justice were infringed. In response, the Attorney General of Alberta stated that a s. 7 *Charter* analysis has to first show there has been a deprivation of life, liberty, or security of the person. The second part of the analysis sets out to determine whether any deprivation has been in accordance with the fundamental principles of justice. In this case, the interveners failed to meet the first stage of the test. The Attorney General added that the AEUB had no jurisdiction to determine the constitutionality of the Alberta regulations as they related to prior AEUB approvals.[214]

The AEUB found that the rights of the interveners had not been infringed by not having compelled Highpine to respond to their information requests. The AEUB also found the informal information requests to be excessive, and in any event, had not been used by any expert called by the interveners.[215]

Likewise, the AEUB did not accept that s. 12.150 of the *Oil and Gas Conservation Regulations*,[216] which treats well information as confidential, operated to deprive the interveners of life, liberty, or security of the person. The AEUB will not approve an operation unless it is satisfied it can be performed in a safe manner.[217] With regard to the claim that voluntary relocation during drilling and the provision of personal information was unconstitutional, the AEUB held again that there was no deprivation of life, liberty, or security of the person because relocations were voluntary and personal information is protected by privacy legislation. Moreover, the fact that numerous safe wells had been drilled over the past decades suggested that there was no infringement of life, liberty, or security of person.[218]

h. Planning and Proliferation

The AEUB chose to comment on the concerns expressed during the hearing regarding appropriate planning and the proliferation of sour gas facilities. The AEUB pointed to its planning and proliferation initiative, with recommendations to reduce proliferation of sour facilities near people and to provide more information regarding future development plans to people who live near sour gas developments. Further, a joint public, industry, and regulatory oversight committee developed industry recommended practices that were to take effect 1 May 2008. Future applications will be held to the new standards, including the updated requirement in ERCB Directive 056[219] to provide a sour gas project map of the assessment area.[220]

[214] *Ibid.* at 25-26.
[215] *Ibid.* at 27.
[216] Alta. Reg. 151/1971 [*OGCR*].
[217] *Supra* note 204 at 28.
[218] *Ibid.* at 29.
[219] *Supra* note 126.
[220] *Supra* note 204 at 30.

10. DECISION 2007-75: *RE: APPLICATION NO. 1478550 — ALTALINK MANAGEMENT LTD., APPLICATION NO. 1479163 — EPCOR TRANSMISSION INC., DECISION 2005-031* AND *DECISION 2006-114*[221]

On its own motion, the AEUB held that it had lost jurisdiction over the controversial Edmonton to Calgary 500 kilovolts (KV) power line hearing due to a reasonable apprehension of bias.

The statutory approval process for power lines involves a two-stage process pursuant to ss. 34 and 35 of the *Electric Utilities Act*.[222] During the first stage, the AEUB considered the location of the Edmonton to Calgary 500 KV power line and favoured an area labelled the "The Western Corridor" as the preferred route. However, several parties objected to the AEUB's decision to place the power line through this location and claimed that they were not given sufficient notice of the AEUB's hearing process and that they were not given a sufficient opportunity to participate in the process.[223]

Dissatisfied parties applied for leave to appeal the AEUB's decisions to the Alberta Court of Appeal. The AEUB nevertheless continued to the second phase of hearings. These hearings became increasingly difficult to manage and suffered continuous disruptions, including instances of physical violence. As a result, the AEUB hired a private contractor to provide security at the hearings. With the approval of a senior AEUB official, a private investigator was also hired and subsequently participated in telephone conference calls during which participants discussed their concerns about the project and the approval process, resulting in allegations of espionage.[224] As a result, parties involved "filed a motion in the Court of Queen's Bench alleging that the EUB's actions in [the] matter raise[d] a reasonable apprehension of bias" and sought leave to appeal from the Alberta Court of Appeal on the basis of an apprehension of bias.[225] In a ruling that pre-empted any final decision from either the Court of Appeal or the Court of Queen's Bench in this matter, the AEUB held that any decision, related review, or application made by the AEUB in relation to the Edmonton to Calgary 500 KV power line proposal must be voided and that the Lieutenant Governor in Council should appoint a new panel with experience and expertise to hear any subsequent application on this matter.[226] The AEUB also held that any directions or instructions from the Court of Appeal and the Court of Queen's Bench would be followed "totally and completely," and the Court of Appeal was expressly invited to provide a legal interpretation of ss. 34 and 35 of the *Electric Utilities Act* for the benefit of future proceedings over this proposal and others.[227]

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221 (30 September 2007), AEUB Decision 2007-75, online: ERCB <http://www.ercb.ca/docs/Documents/decisions/2007/2007-075.pdf> [AEUB Decision 2007-075].

222 *Ibid.* at 4; *Electric Utilities Act*, S.A. 2003, c. E-5.1.

223 AEUB Decision 2007-075, *ibid.*

224 *Ibid.* at 4.

225 *Ibid.*

226 *Ibid.* at 9.

227 *Ibid.* See *Lavesta Area Group v. Alberta (Energy and Utilities Board)*, 2007 ABCA 365, [2007] A.J. No. 1246 (QL) at para. 8: the Alberta Court of Appeal declined to provide such an interpretation on the grounds that the appeals were allowed by consent of all parties, that the AEUB's rulings and orders were therefore quashed, and that the Court was not obliged to decide and comment on all issues.

D. ALBERTA COURT OF APPEAL

1. *KELLY V. ALBERTA (ENERGY AND UTILITIES BOARD)*[228]

Justice Berger of the Alberta Court of Appeal granted leave to appeal from *West Energy Ltd.: Applications for Well Licences, Pembina Field*,[229] where the AEUB conditionally approved West Energy Ltd.'s (West) application to drill two sour oil wells. The first ground upon which leave was granted challenged the AEUB's determination that West's public consultation program addressed the minimum requirements of ERCB Directive 056.[230] The second ground of appeal was a s. 7 *Charter* argument relating to the failure of the AEUB to impose a condition requiring residents living in areas of "unacceptable risk" to relocate during the drilling and completion of the wells, as well as the AEUB's failure to address the question of compensation. The Court rejected the third ground of appeal, which claimed that the AEUB erred in failing to apply ERCB Directive 071[231] by improperly delegating the responsibility of evaluating West's compliance to its officials and employees.[232] The Court found that this claim was without merit as the AEUB had set out the parameters within which the officials ensured compliance.[233] Moreover, the Court noted that s. 18 of the *Alberta Energy and Utilities Board Act*[234] and s. 14 of the *ERCA*[235] allow for the delegation of any of the AEUB's powers and duties.[236]

2. *CARBON DEVELOPMENT PARTNERSHIP V. ALBERTA (ENERGY AND UTILITIES BOARD)*[237]

EnCana and Carbon Development Partnership sought leave to appeal from AEUB Decision 2007-024,[238] where the AEUB decided that coal bed methane (CBM) was gaseous at initial in situ conditions, and the freehold natural gas rights holders, not the coal owners, were entitled to produce CBM. AEUB Decision 2007-024 held that natural gas rights holders Bearspaw, Devon Canada Corporation, and Fairborne Energy Ltd. were "entitled" to the well licences, compulsory pooling, and special well spacing (holding) orders that had been issued to them under s. 16 of the *OGCA*.[239]

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228 2008 ABCA 52, 34 C.E.L.R. (3d) 4.
229 (8 August 2007), AEUB Decision 2007-061, online: ERCB <http://www.ercb.ca/docs/Documents/decisions/2007/2007-061.pdf>.
230 *Supra* note 126.
231 *Supra* note 199.
232 *Supra* note 228 at para. 12.
233 *Ibid.* at para. 13.
234 R.S.A. 2000, c. A-17, as rep. by *Alberta Utilities Commission Act*, S.A. 2007, c. A-37.2, s. 83 [*AUCA*].
235 *Supra* note 128, s. 14.
236 *Supra* note 228 at para. 13.
237 2007 ABCA 343, 425 A.R. 222.
238 *Bearspaw Petroleum Ltd., Devon Canada Corporation, and Fairborne Energy Ltd.: Part 2 of Proceeding No. 1457147 — Review of Certain Well Licences and Compulsory Pooling and Special Well Spacing (Holding) Orders in the Clive, Ewing Lake, Stettler, and Wimborne Fields* (28 March 2007), AEUB Decision 2007-024, online: ERCB <http://www.ercb.ca/docs/Documents/decisions/2007/ 2007-024.pdf> [AEUB Decision 2007-024].
239 *Ibid.* at 33.

Justice Hunt granted leave to appeal on three grounds. She set out the test for the considerations to be made weighed by the court in deciding whether the questions of law or jurisdiction raise a serious, arguable point for appeal: (1) whether "the point on appeal is of significance to the practice"; (2) "significance to the action itself"; (3) or whether the appeal is prima facie meritorious; and (4) whether the appeal "will unduly hinder the progress of the action."[240] Three questions met this test:

1. Did the Board err by taking account of irrelevant considerations in determining that "CBM is a form of gas stored in … coal that is gaseous and distinct from the coal at initial in situ conditions"?

2. Did the Board err by concluding that, notwithstanding the competing proprietary claims of coal interest holders, it had jurisdiction to authorize CBM well licences and spacing and pooling orders for natural gas interest holders?

3. If the answer to question 2 is no, did the Board err in concluding that the natural gas interest holders should receive well licences and pooling and spacing orders for CBM?[241]

The Court rejected leave to appeal on the standard of proof for determining entitlement under s. 16 of the *OGCA* (balance of probabilities) and some procedural fairness issues, largely on the basis that it agreed with the Board's decisions on those points. The Court also indicated that at the leave to appeal stage, it is inappropriate to engage in a full analysis to determine the appropriate standard of review.[242]

3. *GRAFF V. ALBERTA (ENERGY AND UTILITIES BOARD)*[243]

Justice Hunt granted leave to appeal a decision of the AEUB that had denied the applicants' request for review and variance of the AEUB's 8 June 2006 approval of a well licence to EnCana. The licence granted was for a single gas well with no expected production of H_2S, and the request for review and variance was based on adverse effects on health and safety. The AEUB denied the review request on the basis that the landowner (Graff) had failed to show that they were directly and adversely affected by the approval because their land was 18.7 km away and because the well produced no H_2S.[244] The AEUB also stated that there must be a reasonable connection between a party with special needs and the proposed application in order to trigger the consultation process required by the ERCB's Directive 056. Parallel review and variance applications from Darrell Graff were adjourned *sine die* pending determination of whether an AEUB letter was ever mailed to him or his counsel.

A key issue from oral argument was the AEUB's acknowledgement that its decision was based on misinformation, and that the actual distance between the EnCana well and the Graff's land is 2.5 km as was mentioned in Ms. Graff's affidavit. The applicants sought leave to appeal on eight grounds, and were granted leave on three:

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240 *Supra* note 237 at para. 10.
241 *Ibid.* at para. 19 [citations omitted].
242 *Ibid.* at para. 13.
243 2007 ABCA 246, 30 C.E.L.R. (3d) 161.
244 *Ibid.* at para. 6.

> [D]id the Board err in law or jurisdiction:
>
> 1. by concluding that Barbara Graff and Larry Graff were not directly and adversely affected by the EnCana Well;
>
> 2. in its interpretation and application of Directive 056 to Barbara Graff and Larry Graff; or
>
> 3. in failing to take account of the cumulative effect on Barbara Graff and Larry Graff of the EnCana Well along with other wells?[245]

In granting leave to appeal on the first question, Justice Hunt emphasized the AEUB's acknowledgement of its mistake and noted that although the AEUB's finding about direct and adverse effect is typically a matter of fact over which the Court has no jurisdiction, a clear misapprehension of the facts may give rise to an error of law.[246] Justice Hunt stated that both the AEUB's decisions as to who was directly and adversely affected and as to the application of ERCB Directive 056, may have been different if it had been aware of the correct distance. Justice Hunt also indicated that it was arguable that the Board may have made an error of law in overlooking the issue of cumulative effects of hydrocarbon development on the Graffs' health.

E. ALBERTA SURFACE RIGHTS BOARD

The SRB has the authority to grant a right of entry on private and Crown lands to a project that has been approved by the AEUB or its successors. The SRB may also set the rate of compensation.

1. DECISION 2007/0082: *APACHE CANADA LTD. V. O'CONNOR*[247]

On 25 May 2007, the SRB released its decision on an objection made pursuant to s. 15(5) of the *Surface Rights Act*[248] to the SRB's issuance of right of entry orders to Apache Canada Ltd. (Apache). The right of entry orders that were necessary to allow Apache access to develop a subsurface pipeline project that had previously been approved by the AEUB.

At the commencement of the hearing, Apache challenged the SRB's jurisdiction to hear an objection to the issuance of right of entry orders that had been subject to the issuance of a permit or licence from the AEUB. After considering the challenge, the SRB held that s. 15 of the *Surface Rights Act* is permissive and not restrictive in what it allows the SRB to consider in making a decision about surface lands and allows the SRB to hold a hearing as well as attach conditions to its decisions.[249] The SRB stated that an order for right of entry is a form of "taking"

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245 *Ibid.* at para. 13.
246 *Ibid.* at para. 14.
247 (25 May 2007), SRB Decision 2007/0082, online: SRB <http://www.surfacerights.gov.ab.ca/downloads/documentloader.ashx?id=9760> [*Apache*].
248 R.S.A. 2000, c. S-24, s. 15(5).
249 *Supra* note 247 at 2.

> subsurface licensee access from which to develop or transport his product, the taking of rights from the surface owner is one of force. The *Surface Rights Act* provides the Board with the authority to mitigate the effects of the taking.[250]

The SRB held that it had jurisdiction to hold a hearing and make a decision in this matter.[251] After considering the original objection, the SRB heard the evidence of both parties and found that the landowner and the landowner's legal counsel had sufficient notice and ability to participate in the AEUB's hearing process, but chose not to. The SRB granted the right of entry applied for but attached conditions requiring a pre-disturbance environmental assessment to be conducted by Apache.[252]

This decision and the SRB's consideration of the landowner's concerns regarding the AEUB's hearing process appear to be a divergence from the direction traditionally followed by the SRB since the issuance of the Alberta Court of Appeal's decision in *Windrift Ranches Ltd. v. Alberta (Surface Rights Board).*[253] In *Windrift*, the Court of Appeal considered a decision made by the SRB *not* to review the status and licensing of the old ERCB-approved oil well during a right of entry application. The Court of Appeal held that the SRB made the correct decision in refusing to reconsider the oil well licence as the SRB's proceedings were ancillary to and in aid of the activities previously authorized by the ERCB and any other course would permit the appellant to "frustrate the jurisdiction of the E.R.C.B. by putting in issue licensing of oil wells during right of entry proceedings."[254]

The *Apache* decision involved a pipeline licence and not an oil well licence. Moreover, the SRB did recognize that many of the issues and grievances raised by the landowner (such as the location, environmental concerns, timing and type of construction, and impact on the landowner) were outside the SRB's jurisdiction. It was argued that the SRB's very consideration of these objections to the issuance of rights of entry and the subsequent environmental conditions placed on Apache offended the Court of Appeal's ruling in *Windrift*. However, in this case the SRB took jurisdiction under s. 15 of the *Surface Rights Act* to revisit determinations already made by the energy regulator.

2. DECISION 2008/0003: *ARC RESOURCES LTD. V. MACKENZIE*[255]

These right of entry orders related to two parcels of land that were subject to a surface lease agreement signed 30 September 1955 that had subsequently expired in accordance with the terms of the lease as of 29 September 2005. The current landowner, Mr. MacKenzie, opposed the right of entry orders because the lease had expired and ARC Resources Ltd. (ARC) had allegedly failed to meet its obligations to MacKenzie in the past. While claiming that it had met the tasks and requirements set out in previous agreements with the landowner, ARC relied on the fact that it had not yet obtained a reclamation certificate, and therefore,

250 *Ibid.*
251 *Ibid.* at 3.
252 *Ibid.* at 4.
253 (1986), 57 Alta. L.R. (2d) 36 (C.A.) [*Windrift*].
254 *Ibid.* at 40.
255 (9 January 2008), SRB Decision 2008/0003, online: SRB <http://www.surfacerights.gov.ab.ca/downloads/documentloader.ashx?id=9954> [*ARC Resources*].

the surface lease agreement was still valid by operation of s. 144(1) of the Alberta *Environmental Protection and Enhancement Act*.[256] MacKenzie argued that this section of the *EPEA* stipulates that a surface lease cannot be terminated unless a reclamation certificate has been filed.

The SRB held that ARC's argument regarding s. 144(1) of the *EPEA* was not sufficiently supported by the case law as the cases cited by the applicant did not contain any discussion of a surface lease agreement that was at or beyond the 50 year period maximum for such agreements. Therefore, the SRB held that these cases did not present a "ground that a persuasive similarity to the present matter might rest" and that the surface lease was beyond the 50 year limitation for an agreement between the parties.[257] The SRB granted the orders, but with compensation to the landowners in the amount of $6,398.94 and other conditions.

3. DECISION 2008/0015: *PEMBINA PIPELINE CORPORATION V. HALLGREN*[258]

On 24 January 2008, less than three weeks after the *ARC Resources* decision was released, the SRB reviewed and set the rate of compensation owed by Pembina Pipeline Corporation (Pembina) to Mr. Hallgren under a surface lease agreement. Pembina made a preliminary challenge to the SRB's jurisdiction to hear the matter and review compensation as no rent had been paid under the lease since the first year of the agreement, and therefore, the lease had expired as of 1956. Pembina also argued that s. 144 of the *EPEA*, which stipulates that a surface lease cannot be terminated unless a reclamation certificate has been filed, does not apply because, according to s. 144(2)(b), this section of the *EPEA* only applies to leases in effect on or after 1 June 1963.

Despite *ARC Resources*, the SRB held that s. 144 can be interpreted to mean that a surface lease cannot be terminated without a reclamation certificate and that any limitation under s. 144(2)(b) applies only to right of entry orders, not surface lease agreements. Because no evidence was presented that a reclamation certificate had been issued, the SRB held that the surface lease agreement was still in effect and the SRB had jurisdiction to hear a review of annual compensation in this matter.[259]

While it did not have the jurisdiction to retroactively review annual rentals over a 50 year period, the SRB did review the annual compensation from the date the request for review was made, that being 17 November 2005. The SRB set the annual compensation in this matter at $2,535, effective 11 October 2005.[260]

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256 R.S.A. 2000, c. E-12, s. 144(1) [*EPEA*].
257 *Supra* note 255 at 8.
258 (24 January 2008), SRB Decision 2008/0015, online: SRB <http://www.surfacerights.gov.ab.ca/downloads/documentloader.ashx?id=9958>.
259 *Ibid.* at 6.
260 *Ibid.* at 9.

4. *CANADIAN NATURAL RESOURCES LTD. V. BENNETT & BENNETT HOLDINGS LTD.*[261]

CNRL was the lessee of 11 surface leases of lands owned by Bennett & Bennett Holdings Ltd. and Circle B Holdings Ltd. (Bennett). CNRL provided annual compensation for the leases to Bennett, and the rate of compensation was reviewable every five years. In 2005, CNRL had unsuccessfully attempted to negotiate compensation reductions on a number of the leased lands. The matter proceeded to a hearing at the SRB. Without providing reasons for its decision, the SRB increased the annual compensation for each of the surface leases payable to Bennett by CNRL. CNRL therefore applied to the Alberta Court of Queen's Bench for judicial review of the decision.

The Court found that despite not providing sufficient reasons for its decision, the SRB was still owed deference given that the issues fell squarely within the SRB's expertise. The Court found that while the "adverse effect" compensation awarded by the SRB may have been high, the compensation level was reasonable and would not be disturbed.[262]

However, the Court did find that the evidence could not reasonably support the categorization used by the SRB to calculate loss of use rates on a per acre basis. The Court found a complete absence of reasoning for the SRB's categorization. Therefore, the Court substituted its judgment, finding irrigated sites should be awarded $500 (instead of $600) per acre for loss of use compensation and that dry land sites would remain at $350 per acre.[263]

F. OFFSHORE PETROLEUM BOARDS

1. *HIBERNIA MANAGEMENT AND DEVELOPMENT CO. LTD. V. CANADA-NEWFOUNDLAND OFFSHORE PETROLEUM BOARD*[264]

In this case, the Newfoundland and Labrador Supreme Court (Trial Division) (NLTD) dismissed an application by several offshore petroleum project operators for judicial review of a decision of the Canada-Newfoundland Offshore Petroleum Board (OPB) relating to the establishment of a set of guidelines for research and development expenditures (R&D Guidelines) to be applied to all existing and future offshore petroleum projects subject to the *Canada-Newfoundland Atlantic Accord Implementation Act*[265] and the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*[266] (*Accord Acts*). The NLTD found that the OPB had the authority to implement the R&D Guidelines.

The R&D Guidelines established expenditure obligations for offshore petroleum projects and set out the percentage of total annual revenue that an operator was required to spend on research and development in the province. The OPB estimated that the annual costs of this

261 2008 ABQB 19, 436 A.R. 256.
262 *Ibid.* at para. 156.
263 *Ibid.* at paras. 162-63.
264 2007 NLTD 14, 263 Nfld. & P.E.I.R. 40.
265 S.C. 1987, c. 3.
266 R.S.N.L. 1990, c. C-2.

expenditure would be approximately $3.7 million for each offshore petroleum project. However, the actual amount of required expenditures would be dependent on a five-year moving average benchmark and the price of oil.[267] Offshore petroleum project operators, Hibernia Management and Development Co. Ltd. (Hibernia) and Petro-Canada applied for judicial review of the OPB's decision, submitting that the OPB was exercising power and authority it did not possess under the *Accords Acts* and that the OPB's decision amended the benefits plan already established and agreed to with the provincial and federal governments as part of the project approval process. Hibernia further submitted that OPB was *functus officio* and that the R&D Guidelines were a form of tax that the OPB did not have authority to levy.[268]

The OPB submitted in response that the *Accords Act* required and gave authority to it to make polycentric policy decisions and that the Court, in judicially reviewing the OPB's decision, owed significant deference to the OPB.[269] The OPB further submitted that the R&D Guidelines form an administrative tool to implement its statutory mandate and are to be used to ensure statutory compliance by offshore petroleum project operators under the *Accord Acts*.

The Court found that the appropriate standard of review was the standard of reasonableness.[270] A purposive interpretation of the legislation provided authority to establish reasonable levels of expenditure in relation to research, development, education, and training as part of the OPB's ongoing monitoring and enforcement role under the *Accord Acts*. Moreover, the establishment of the R&D Guidelines did not interfere with any vested rights of Hibernia. Hibernia's initial ability to proceed with their respective offshore petroleum projects was dependent on approval and authorization by the OPB. Therefore, in previously accepting these approvals subject to the OPB's ongoing role in determining the appropriateness of expenditures being made in relation to and for the duration of the offshore petroleum projects as set out in the *Accord Acts*, Hibernia could not deny the OPB's authority to develop the R&D Guidelines.[271] The Court further held that OPB's continuous authority to assess expenditures in relation to research and development of offshore petroleum projects pursuant to the *Accord Acts* rendered the doctrine of *functus officio* inapplicable.

The Court also held that it was neither patently unreasonable nor unreasonable for the OPB to establish a required level of expenditure that would be dependent on industry norms such as the price of oil and be subject to a five-year moving average benchmark.[272]

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267 *Supra* note 264 at para. 4.
268 *Ibid.* at para. 7.
269 *Ibid.* at para. 11.
270 *Ibid.* at para. 27.
271 *Ibid.* at para. 47.
272 *Ibid.* at paras. 48-51.

G. FEDERAL ENVIRONMENTAL DECISIONS

1. FEDERAL MINISTER OF THE ENVIRONMENT APPROVAL OF KELTIC LIQUEFIED NATURAL GAS FACILITIES AND MARGINAL WHARF PROJECT[273]

On 7 March 2008, the federal Minister of the Environment approved the Environmental Assessment and Comprehensive Study Report for the Keltic LNG Facilities and Marginal Wharf Project proposed to be constructed at Isaacs Harbour, Nova Scotia. The project will eventually include a wharf, marine terminal, transfer pipelines, storage tanks, and re-gasification facilities. The project will be located adjacent to the Maritimes and Northeast Pipeline intake station at the SOEI Gas Plant in Goldboro, Nova Scotia, and is intended to facilitate access for natural gas from Nova Scotia to markets in Eastern Canada and the Northeastern U.S.

The Minister's approval was delayed by several months due to concerns about a threatened population of birds (Roseate Tern) residing on a small island near the project site. The Minister eventually granted the approval on the condition that the proponents commission studies on the foraging habits of the birds and that no LNG tankers come within 200m of the island. Having received provincial environmental approval in March 2007, the project will now require approvals from the federal Ministries of Fisheries and Oceans Canada and Transport Canada, as well as approval from the Nova Scotia Utility and Review Board.

III. LEGISLATIVE DEVELOPMENTS

A. FEDERAL

1. *OIL AND GAS OPERATIONS ACT* AMENDMENTS

The *Canada Oil and Gas Operations Act*[274] was amended by Part 9 of Bill C-28. The *COGOA* applies to various types of oil and gas operations that are carried out in frontier lands (for example, the Northwest Territories, Nunavut, Sable Island, submarine areas not within a province but in the internal waters of Canada, the territorial sea of Canada, the continental shelf of Canada, and so on).

In addition to making the NEB's powers over oil and gas operations regulated under the *COGOA* more robust, the *COGOA* was amended to provide the NEB with authority to regulate the traffic, tolls, and tariffs of pipelines that fall within its scope. The additions to the *COGOA* in this regard are patterned closely after provisions in the *NEB Act* governing the traffic, tolls, and tariffs of pipelines that fall within the scope of that *Act*. Examples of new provisions added to the *COGOA* include:

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273 Canadian Environmental Assessment Agency (CEAA), Environmental Assessment Decision Statement, "Keltic Liquified Natural Gas Facilities and Marginal Wharf Project" (7 March 2008), online: CEAA <http://www.ceaa-acee.gc.ca/050/document-eng.cfm?DocumentID=25805>.

274 R.S.C. 1985, c. O-7, as am. by *Budget and Economic Statement Implementation Act, 2007*, S.C. 2007, c. 35 [*COGOA*].

- The holder of an authorization under the *COGOA* to construct or operate a pipeline ("holder") is precluded from charging any tolls unless they are specified in a tariff filed with the NEB or approved by an order of the Board.[275]

- Tolls must be "just and reasonable and shall always under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate."[276]

- The NEB may approve interim tolls, and may make subsequent orders adjusting those tolls on a retrospective basis, including awarding interest on the difference between interim and final tolls.[277]

- A holder is precluded from making "any unjust discrimination in tolls, service or facilities against any person or locality."[278] Once discrimination is shown, the holder bears the onus of demonstrating that the discrimination is not unjust.[279]

- The NEB has the authority to determine the extent to which a holder may limit its liability in respect of the transmission of oil, gas, and so on.[280]

- The NEB may require a holder operating a gas pipeline to receive, transport, and deliver oil or gas, or any other substance incidental to drilling or production offered for transmission by means of its pipeline.[281]

- The NEB may require a holder of an oil or gas pipeline to provide adequate and suitable facilities for the receipt, transmission, delivery, and storage of substances, and interconnections with other facilities.[282]

- A holder may not, without leave of the NEB, sell, transfer, purchase, or lease a pipeline, enter into an agreement to amalgamate with any person, or abandon the operation of a pipeline.[283]

B. ALBERTA

1. SPLIT OF THE ALBERTA ENERGY AND UTILITIES BOARD

On 1 January 2008, the AEUB was split into two separate and independent regulatory agencies, the ERCB and the AUC. The split represents a return to the model that was in place prior to the formation of the AEUB in the mid-1990s. The legislation creating the two new

275 *Ibid.*, ss. 13.03(1)(a)-(b).
276 *Ibid.*, s. 13.05.
277 *Ibid.*, s. 13.07.
278 *Ibid.*, s. 13.1.
279 *Ibid.*, ss. 13.1-13.12.
280 *Ibid.*, s. 13.13.
281 *Ibid.*, s. 13.14.
282 *Ibid.*
283 *Ibid.*, s. 4.01.

boards, the *AUCA*,[284] provides consequential amendments to various energy statutes indicating which of the new tribunals are responsible. Likewise, the *Energy Regulations Amendment Regulation*[285] sets out how the various energy regulations are allocated between the two bodies. For the transition, proceedings that have been initiated by the AEUB will be completed by the AEUB in accordance with s. 80 of the *AUCA*. For example, the inquiry into potential inequities surrounding the conventions and practices with respect to the removal of Natural Gas Liquids from natural gas at large extraction facilities remains a joint energy/utilities inquiry that is being handled by staff from both the ERCB and the AUC.[286] A decision by the AEUB is expected in the fourth quarter of 2008.

Going forward, the ERCB is responsible for the regulatory framework of Alberta's petroleum resources and generally focuses on overseeing the orderly, safe, and environmentally acceptable development of oil, oil sands, natural gas, and coal resources in the province. This includes the approval and regulation of oil and gas wells, batteries and other related facilities, oil sands development and production, pipeline infrastructure (other than gas utility pipelines), coal resource projects, and equitable remedies.

The *ERCA*[287] was also amended by the *AUCA* to add a number of powers and protections for the ERCB. These include the statutory power to appoint a Chief Executive and ability of the Chair to remove a member from sitting on division if, in the opinion of the Chair, the member is not properly carrying out his or her duties.[288]

The AUC's responsibility generally focuses on the regulatory approval of power generation facilities, power transmission lines, and gas distribution pipelines in the province, as well as the regulation of electric, gas, and water utility rates and tariffs. As of 1 January 2008, the AUC also regulates the construction and operation of gas utility pipelines in accordance with s. 4.1 of the *Gas Utilities Act*,[289] and has the jurisdiction to exercise all powers, functions, and duties of the ERCB under the *Pipeline Act*,[290] for any gas utility pipeline of a designated gas utility or its affiliate. The AUC is also charged with administering industrial systems under the *Hydro and Electric Energy Act*[291] including industrial systems associated with oil and gas facilities.

Another aspect of the AUC's regulatory authority is to oversee determinations made by two other statutory agencies: the Independent System Operator, who is responsible for administering the provincial transmission system and power pool, and the Market Surveillance Administrator, who is responsible for investigating and enforcing market conduct.

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284 *Supra* note 234.
285 Alta. Reg. 254/2007.
286 *Inquiry into Natural Gas Liquids (NGL) Extraction Matters* (4 February 2009), AEUB Decision 2009-009, online: ERCB <http://www.ercb.ca/docs/documentsdecisions/2009/2009-009.pdf>.
287 *Supra* note 128.
288 *Supra* note 234, ss. 5, 8(7).
289 R.S.A. 2000, c. G-5, s. 4.1.
290 R.S.A. 2000, c. P-15.
291 R.S.A. 2000, c. H-16.

Currently, the AUC is considering a proceeding relating to whether the generic cost of capital adjustment formula determined by the AEUB in 2004 continues to yield a fair return on equity and whether capital structures should also be addressed on a generic basis.[292] The AUC is also set to consider an application from NOVA Gas Transmission Ltd. (NGTL), a wholly owned subsidiary of TransCanada, regarding an annual revenue requirement settlement it reached with shippers and other parties in relation to the Alberta system. NGTL's application will also include a determination of final tolls for 2008.[293]

2. ROYALTY CHANGES

On 25 October 2007, the Alberta government released its new policy on oil and gas royalties,[294] representing the first major revision to Alberta's provincial royalty regime in over 30 years. While generally consistent with the Report of the Alberta Royalty Review Panel entitled *Our Fair Share*[295] released on 18 September 2007, there are some important differences. The new policy became effective 1 January 2009, and but for a few exceptions, industry will see a significant increase in royalty rates, with the Alberta government predicting a 20 percent increase in royalty revenues. The Alberta government has explicitly left open the ability to change the new policy to avoid "unintended consequences."[296] While the new policy does provide some royalty relief for older, lower producing wells in an attempt to increase their longevity, the new policy shifts the royalty burden to the new higher risk and higher impact deep gas wells and the oil sands.

In regard to conventional natural gas, the resource will be subject to a single sliding scale royalty that is sensitive to prices and production volumes. The rate will range from 5 percent to 50 percent with the higher price being payable on high volume wells when gas prices reach $16.59 per GJ.[297]

In regard to conventional oil, the resource will be subject to a sliding scale royalty that will also be sensitive to prices and production volumes and the rate will range from 0 percent to 50 percent with the maximum rate being payable on high volume wells when oil prices reach $120 per barrel.[298] The Alberta government will also eliminate the distinction between old and new production and discontinue specialty programs with no grandfathering of existing projects.

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292 *All Commission Regulated Utilities, Generic Cost of Capital – Preliminary Questions Proceeding* (18 June 2008), AUC Decision 2008-51, online: AUC <http://www.auc.ab.ca/applications/decisions/Decisions/2008/2008-051.pdf>.

293 For interim rate determinations, see *NOVA Gas Transmission Ltd.: 2008 Interim Rates, Tolls, and Charges* (20 December 2007), AEUB Decision 2007-109, online ERCB <http://www.ercb.ca/docs/Documents/decisions/2007/2007-109.pdf>.

294 Government of Alberta, *The New Royalty Framework*, online: Alberta Energy <http://energy.gov.ab.ca/Org.Publications/royalty_Oct25.pdf>.

295 Alberta Royalty Review Panel, *Our Fair Share* (18 September 2007), online: Alberta Royalty Review <http://www.albertaroyaltyreview.ca/panel/final_report.pdf>.

296 *Supra* note 294 at 14.

297 *Ibid.* at 3.

298 *Ibid.* at 7.

In regard to oil sands, the pre-payout gross royalty rate on revenue will no longer be a flat 1 percent. Instead, oil sands will also be subject to a sliding scale that is price sensitive with gross royalty rates pre-payout ranging from 1 percent to 9 percent with net revenue royalties after payout ranging from 25 percent to 40 percent, in each case fluctuating as prices shift between \$55 and \$120 per barrel.[299] While there will be no grandfathering of existing oil sands projects, the Alberta government did acknowledge that Syncrude Canada Ltd. and Suncor Energy Inc. oil sands mines were special situations that will require further negotiation.

3. GREENHOUSE GAS EMISSIONS LEGISLATION

On 8 March 2007, the Alberta government introduced its new climate change legislation and became the first jurisdiction in North America to introduce GHG emissions reduction legislation. The *Climate Change and Emissions Management Act,*[300] and its corresponding regulation, the *Specified Gas Emitters Regulation,*[301] came into force on 1 July 2007 and represent an intensity-based cap-and-trade system with the goal of a 50 percent reduction of GHG emissions from 1990 emission levels relative to gross domestic product by 2020 and a 50 percent reduction from business as usual projections for 2050. Therefore, large emitters that emit over 100,000 tonnes of CO_2 per year will be required to reduce their CO_2 levels by 12 percent a year beginning in 2007.

Established facilities, defined as any facility that had "completed its first year of commercial operation before January 1, 2000, or has completed 8 years of commercial operation,"[302] must not exceed 88 percent of its "baseline emissions intensity,"[303] that being the average of the ratio of total annual emissions to production between the years 2003 and 2005. The Government also has the ability to establish a new baseline emissions intensity for any facility if the need should arise.[304]

New facilities are defined as having completed their first year of commercial operation on 31 December 2000, or in a subsequent year, and having completed less than eight years of commercial operation, or as having been designated as "new" by the director.[305] New facilities' targets will be based on the facility's year of commercial operation and on a baseline emissions intensity calculated through the ratio of total annual emissions to production in the third year of commercial operation. After the eighth year of commercial operation, a facility will meet the definition of "established facility" and will be required to meet the targets set out above.[306] This effectively gives a facility that begins commercial operation in the year 2000 or later a nine-year grace period to fully meet Alberta's new regulatory requirements.

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299 *Ibid.* at 3.
300 S.A. 2003, c. C-16.7.
301 Alta. Reg. 139/2007 [*SGER*].
302 *Ibid.*, s. 1(1)(i).
303 *Ibid.*, s. 3(2).
304 *Ibid.*
305 *Ibid.*, ss. 1(1)(p), 1(2).
306 *Ibid.*, ss. 1(1)(i), 4 (1).

Given the short time frames involved, facilities can also meet at least part of their targets through the following three regulatory compliance options:

(1) *Emission Performance Credits*: These credits can be earned when a facility's actual emissions intensity is less than the applicable net emissions intensity for the period. These credits can be banked and used at the same facility in the future or can be transferred to another facility with the condition that they must be used in the same year as they are transferred.[307]

(2) *Climate Change and Emissions Management Fund*: These credits can be purchased for $15 each to offset one tonne of CO_2 equivalent emissions. These credits can only be used to offset emissions in the year that they are purchased.[308]

(3) *Offset System*: Facilities can also purchase government-approved offsets generated in Alberta to meet their reduction requirements. These offsets must occur in Alberta and in order to be approved must reduce GHG emissions in a real, demonstrable, quantifiable, and measurable way.[309]

The Alberta GHG legislation appears to be materially different in a number of ways from the federal government's regulatory framework for industrial GHG emissions released in March 2008.[310] There are key differences between the federal Technology Fund and Alberta's Climate Change and Emissions Management Fund in that the federal system is the only one to incorporate both increasing contributions rates and decreasing contribution limits over time. The Alberta GHG legislation does not contemplate any links with the *Kyoto Protocol* or any other emissions trading scheme and Alberta's reduction requirements for existing facilities are only 12 percent compared to 18 percent under the federal framework. Alberta's GHG legislation allows credits generated from 2002 to be used as opposed to 2008 under the federal framework. Unlike the federal framework, there are no provisions for continuous annual intensity improvements under Alberta's GHG legislation. Finally, the applicability threshold for certain sectors is significantly lower in the federal framework.

4. NORTH SASKATCHEWAN RIVER BASIN WATER MANAGEMENT FRAMEWORK

The Alberta government introduced *The Water Management Framework for the Industrial Heartland and Capital Region*[311] for the North Saskatchewan River Basin, also known as the Industrial Heartland and Capital Region. The Framework was introduced under the Alberta government's recently released environmental plan to deal with cumulative effects of industrial development in Alberta on a region-by-region basis. The Industrial Heartland and

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307 *Ibid.*, s. 9.

308 *Supra* note 302, s. 10; *ibid.*, s. 8.

309 *SGER*, *ibid.*, s. 7.

310 Canada, *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions* (Ottawa: Environment Canada, 2008), online: <http://www.ec.gc.ca/doc/virage-corner/2008-03/pdf/ COM-541_Framework.pdf>.

311 Alberta Environment, *The Water Management Framework for the Industrial Heartland and Capital Region* (Edmonton: Alberta Environment, 2007), online: AE <http://www.environment.gov.ab.ca/info/library/7864.pdf>.

Capital Region was chosen as the first region to be addressed under the Government's plan. The plan is also being applied in two other regions of Alberta, as well as in Northeastern Alberta in relation to water supply concerns for the Athabasca River, and in the context of the development of a regional sustainable development strategy for the oil sands.

The Framework focuses on the water quantity and quality issues that have arisen from the high volume of ongoing and planned industrial development in the Industrial Heartland and Capital Region, as well as from municipal and agricultural users. Concerns related to eutrophication, the discharge of contaminants into the aquatic ecosystem, and the projected increases in water usage with increasing development were among the key issues considered in formulating the framework.

The Framework will be introduced gradually into Alberta's regulatory regime in three broad phases. The first phase is expected to run from the present until 2009. During this phase, an oversight committee will begin to establish the governance and funding needed to implement the framework. All projects currently in the regulatory queue will go ahead, however, it is possible that approval may be denied to any new physical intakes on the North Saskatchewan River (NSR). During this phase, the Government will also strive: (1) to ensure that the quality of the river water does not degrade any further; (2) to operate under targets set by Alberta Environment related the Threshold Conditions for NSR water quality and quantity; and (3) to use existing infrastructure locations for current developments to minimize the footprint on the NSR.[312]

In the second phase, which is expected to run from 2009 to 2012, "new and future planned upgraders will have moved through the regulatory phase. This phase will provide for industry development, enabling industry to make the transition to the new regional system(s) as the existing withdrawals are upgraded to current standards … or … phased out as they reach the end of their service life."[313] During this phase, the Government will continue to promote and further develop the use of reclaimed water for all non-potable water needs. It will also work to upgrade water-related infrastructure to create an Industrial Heartland supply network, which industry will be gradually required to use through the operating licence renewal process.[314]

The third and final phase is expected to extend from 2012 until 2041, with "the integration of existing facilities into the framework, making an integrated supply network for the Industrial Heartland."[315] The regional water management system will be economically competitive with other areas, with improved water quality in the NSR and minimal loading discharge for return flows to the NSR. The primary source of water for all non-potable demands will be reclaimed water, and there will be minimal use of withdrawal infrastructure and raw water by industrial process users. This final phase will also see increased "secondary processing and sustainable management of solids from water treatment and effluent reclamation."[316] By this point, all major policy and investment decisions will be evaluated

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[312] *Ibid.* at 19-20.
[313] *Ibid.* at 21.
[314] *Ibid.* at 21-22.
[315] *Ibid.* at 22.
[316] *Ibid.* at 23.

for their environmental benefit, based on full life cycle costs and measurable environmental outcomes.[317]

IV. DEVELOPMENTS IN POLICY, DIRECTIVES, AND GUIDELINES

A. NATIONAL ENERGY BOARD

1. NATIONAL ENERGY BOARD'S LAND MATTERS CONSULTATION INITIATIVE

In January 2008, the NEB formally implemented the Land Matters Consultation Initiative (LMCI). The purpose of the LMCI is to assist the NEB in identifying ways to improve the processes and procedures in place so that land matters are effectively and appropriately included in the NEB's public interest considerations. The LMCI is intended to

> provide a forum for all interested parties … to engage in dialogue and generate options for the Board's review of issues relating to land matters, … [focusing] primarily on the range of tools available (such as regulations, guidance notes, filing manual, inspections, audits, etc.) under the existing legislative framework and improvements to that suite of tools.[318]

In a document entitled "Land Matters Consultation Initiative Proposed Approach,"[319] the NEB proposed that it would consider the LMCI in the four streams described below.

a. Company Interactions with Landowners

This stream will focus on "selected land matters that have been raised by landowners as issues of concern and which broadly include interactions between landowners and a pipeline company"[320] from contemplation to the end of an infrastructure project. The NEB wants to develop "a common understanding among parties about existing mechanisms and processes … [and] to develop ways to address [a number of topics] … to ensure that processes are meeting parties' needs efficiently and effectively."[321] The specific topics to be addressed in this stream include:

- Landowner Notification and Company Consultation Programs
  Meeting notification requirements and identification of best practices for consultation

- Process of Acquiring Access to Right of Way
  Procedures for providing notice, sharing information and reaching timely agreements

[317] *Ibid.* at 22-23.
[318] Letter from NEB to Aboriginal Organizations (17 January 2008), ADV-PE-LandMC 01, online: NEB <https://www.neb-one.gc.ca/ll-eng/livelink.exe/fetch/2000/90463/501413/501488/501127/501372/A1D1C9/Land_Matters_Consultation_Initiative.pdf?nodeid=501174&vernum=0> at 1.
[319] NEB, "Land Matters Consultation Initiative Proposed Approach" (17 January 2008) in *ibid.*
[320] *Ibid.* at 2.
[321] *Ibid.*

- Vehicle Crossings of the Right of Way
  Identification of consistent and appropriate processes for seeking permission to cross.[322]

The potential outcomes identified by the Board for this stream is the identification of possible approaches to verify compliance, including landowner surveys, audits, and inspections of company practices and records.[323]

b. Improving the Accessibility of NEB Processes

This stream will focus on "the NEB's application review and hearing process for proposed facilities, and … other processes such as the [Board's] landowner complaint and Appropriate Dispute Resolution processes."[324] It is intended to address landowner comments that "it can be difficult to participate effectively in the NEB's processes, such as public hearings for proposed facilities," due to such factors as the formality of the oral hearing process, a lack of funding for interveners, and the lack of capacity of the public to intervene without legal representation.[325] The NEB also wants to deal with the perception of some landowners that the transparency of the NEB's decision-making processes could be improved. The Board's primary goals in the stream are to gain a better understanding of landowners' concerns in these areas and to develop options for improving access to NEB processes.[326] Hearings relating to toll and tariff matters will not be included in this stream.

c. Pipeline Abandonment – Financial Issues

This stream will focus on key principles that should guide the NEB in its deliberations with respect to the financial matters relating to pipeline abandonment. Two key principles are identified by the NEB as being fundamental to its future decisions with respect to these financial matters: (1) "Abandonment costs are a legitimate cost of providing service and are recoverable upon Board approval from users of the system"; and (2) "Landowners will not be liable for costs of pipeline abandonment."[327] The key issue before the NEB in this stream is to determine "the optimal way to ensure that funds are available when abandonment costs are incurred."[328] The NEB hopes to develop a set of principles to guide its future decisions on these financial matters, identify a mechanism for setting aside funds for abandonment costs, identify technical abandonment assumptions for use in estimating abandonment costs, and develop an action plan to move forward on other financial issues including those unique to each pipeline company.[329]

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322 *Ibid.*
323 *Ibid.* at 3.
324 *Ibid.*
325 *Ibid.*
326 *Ibid.*
327 *Ibid.* at 5.
328 *Ibid.*
329 *Ibid.*

d. Pipeline Abandonment – Physical Issues

This stream will focus on the physical aspects of pipeline abandonment. The NEB intends to “confirm the existing state of knowledge and … explore the possibility for collaboration on a plan for future research related to the physical issues of abandonment.”[330] The key issues for the NEB in this stream include: “How should the desired end-state of land post-abandonment be defined?” and “What is the optimal way of ensuring the desired end-state is achieved?”[331]

The NEB notes that a potential starting point for initiating discussion regarding these questions may be to consider:

- the NEB’s goals of ensuring “facilities and activities are safe and secure, and perceived to be so,” and ensuring “facilities are built and operated in a manner that protects the environment and respects the rights of those affected”; and

- the reclamation requirements set out in s. 21 of the *Onshore Pipeline Regulations, 1999*.[332]

Starting in February 2008, the NEB released discussion papers and background notes on each of the four streams, which were followed by opportunities for participation by interested parties. Depending on the specific stream in question, final reports dealing with the results of the LMCI will be issued by the NEB in May of 2009.[333]

B. ENERGY RESOURCES CONSERVATION BOARD

1. DIRECTIVE 056: *ENERGY DEVELOPMENT APPLICATIONS AND SCHEDULES* — REQUIREMENTS FOR SOUR GAS DEVELOPMENT[334]

ERCB Directive 056 was amended, effective May 2008, to increase application requirements for sour gas developments near people. Among the new requirements are: conducting an assessment on the feasibility of using existing facilities within a 15 km radius and expanding the project specific information package to include a Sour Gas Project map of the assessment area.[335] In circumstances where “there are no outstanding unresolved objections or concerns, … applicant[s] may file a routine application with a letter indicating that no objections exist and that the applicant [has] followed the recommended practices.”[336]

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330 *Ibid.* at 6.
331 *Ibid.* at 7.
332 S.O.R./1999-294; *ibid.* at 6.
333 See online: NEB <http://www.neb.gc.ca/clf-nsi/rthnb/nvlvngthpblc/lndmttrs/lndmttrs-eng.html>.
334 *Supra* note 126.
335 ERCB, Bulletin 2008-04, “Application Requirements for Sour Gas Development — Directive 056” (28 January 2008), online: ERCB <http://www.ercb.ca/docs/documents/bulletins/bulletin-2008-04.pdf> at 2.
336 *Ibid.*

2. DIRECTIVE 020: *WELL ABANDONMENT GUIDE* AMENDMENTS[337]

Sections 4.6.2 and 5.4.2 of ERCB Directive 020 were amended, effective 7 December 2007,[338] as follows:

- All wells being abandoned at surface must be vented in a manner that prevents the potential buildup of pressure in any casing string;
- The option to use eight linear metres of cement and a wiper plug to cap wells at surface was eliminated;
- The method used to vent casing must be documented, retained by the licensee, and made available to the EUB upon request.

3. DIRECTIVE 071: *EMERGENCY PREPAREDNESS AND RESPONSE REQUIREMENTS FOR THE PETROLEUM INDUSTRY*[339]

The ERCB has continued its process to update ERCB Directive 071, which will include use of the ERCB's dispersion model, the *ERCBH$_2$S Model*, to calculate the EPZ for sour wells, pipelines, and facilities. As the AEUB indicated in recent decisions, the EPZ can actually be smaller when the *ERCBH$_2$S Model* method is used to calculate the EPZ relative to the old nomograph method.[340] On 2 January 2008, the ERCB posted a revised *Draft Directive 071* on its website for further stakeholder review.[341] The proposed changes include clarification of the jurisdiction of the ERCB and that of local authorities, a clearer identification of the "must" requirements that will attract enforcement in accordance with ERCB Directive 019, and continuous updating and reviews of ERPs.[342]

4. BULLETIN 2007-28: CONSULTATION ON PROPOSED OILFIELD WASTE LIABILITY (OWL) PROGRAM AND CHANGES TO THE LICENSEE LIABILITY RATING (LLR) PROGRAM BASED ORPHAN FUND LEVY[343]

A consultation process for a proposed Oilfield Waste Liability (OWL) Program and Licence Transfer Process was initiated on 8 August 2008. The proposed OWL Program would replace the current full security deposit requirements for oil field waste management

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337 AEUB, Bulletin 2007-42, "Regulatory Changes to EUB *Directive 020: Well Abandonment Guide*" (7 December 2007), online: ERCB <http://www.ercb.ca/docs/documents/bulletins/bulletin-2007-42.pdf>; ERCB, Directive 020, "Well Abandonment Guide" (7 December 2007), online: ERCB <http://www.ercb.ca/docs/Documents/directives/Directive020.pdf> [ERCB Directive 020].

338 ERCB, Directive 020, *ibid.* at 1.

339 *Supra* note 199.

340 *Supra* note 191 at 12.

341 ERCB, Bulletin 2008-01, "Update on *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry* and Request for Stakeholder Feedback" (2 January 2008), online: ERCB <http://www.ercb.ca/docs/documents//bulletins/Bulletin-2008-01.pdf> [ERCB Bulletin 2008-01]. ERCB Directive 071 has since been fully updated and brought into force. See *supra* note 199.

342 ERCB Bulletin 2008-01, *ibid.* at 1.

343 AEUB, Bulletin 2007-28, "Consultation on Proposed Oilfield Waste Liability (OWL) Program and Changes to the Licensee Liability Rating (LLR) Program Based Orphan Fund Levy" (8 August 2007), online: ERCB <http://www.ercb.ca/docs/documents/bulletins/Bulletin-2007-28.pdf>.

facilities under part 16.6 of the *OGCR* with a risk-based industry backstopped liability management program.

> [L]andfills held under Oilfield Waste Management (WM) Approval would continue to be administered under Part 16.6 of the *Oil and Gas Conservation Regulations* and remain subject to full security deposit requirements.
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> …
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> The proposed program is very similar to the EUB's existing LLR Program. The EUB would compare a WM Approval holder's deemed assets in the OWL … to its deemed liabilities.… [T]he cost to suspend, abandon, remediate, and reclaim an "orphaned" oilfield waste management facility [would be] assumed by the Orphan Fund, while the total deemed liability of OWL sites would be included in the Orphan Fund Levy.
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> …
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> [F]or a nonproducer licensee (NPL) or a producer licensee having a liability management rating less than 1.0 (eligible producer licensee), the OWL Program compares the deemed assets of each facility in the OWL Program to its deemed liabilities and requires a facility-specific security deposit for the difference.… An NPL or eligible producer licensee acquiring a new or existing waste management facility would be required to provide a security deposit for the full deemed liability of the facility until … it has 12 calendar months of throughput.[344]

The program also proposes to licence existing waste management facilities and to grandfather the WM Approval holders from the requirements of ERCB Directive 067.[345] "Parties not already holding a WM Approval … must fully comply with *Directive 067*."[346]

5. BULLETIN 2007-16: PUBLIC AVAILABILITY OF EUB ENFORCEMENT INFORMATION[347]

> The EUB Monthly Enforcement Action Summary summarizes High Risk Enforcement Action 1, High Risk Enforcement Action 2 (Persistent Noncompliance), High Risk Enforcement Action 3 (Failure to Comply or Demonstrated Disregard), Low Risk Enforcement Action — Global REFER, and Legislative/Regulatory Enforcement Action noncompliance enforcement information, including company names.
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> …
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> Publication of the monthly summary will occur within 120 days of the enforcement actions. This period of time allows [for] completion of review and appeal processes.… Any enforcement action with an appeal

344 *Ibid.*

345 ERCB, Directive 067, "Applying for Approval to Hold EUB Licences" (11 July 2005), online: ERCB <http://www.ercb.ca/docs/Documents/directives/Directive067.pdf>.

346 *Supra* note 343 at 2.

347 AEUB, Bulletin 2007-16, "Public Availability of EUB Enforcement Information" (19 June 2007), online: ERCB <http://www.ercb.ca/docs/documents/bulletins/Bulletin-2007-16.pdf>.

> pending within the EUB will not be included in the summary. Any enforcement action subsequently continued after an unsuccessful appeal will be included in a later monthly summary.[348]

6. DIRECTIVE 065: *RESOURCES APPLICATIONS FOR CONVENTIONAL OIL AND GAS RESERVOIRS*[349] — REVISIONS FOR COMMINGLING AND COMPLIANCE ASSURANCE

The EUB revised ERCB Directive 065 to implement the next phase of the comingling plan and to update compliance requirements to be consistent with ERCB Directive 019.[350] Commingling production from two or more pools in the same well bore is permitted where the requirements of s. 3.051 of the *OGCR* are met.[351] Bulletin 2006-38,[352] provides guidance on these requirements, including that the licensee must resolve concerns with other mineral owners that may be affected by unsegregated production.[353] The amendments to ERCB Directive 065 allow applicants to focus on criteria that did not permit commingling to occur under the development entity or self-declared commingling requirements set out in s. 3.051 of the *OGCR.* The amendments to ERCB Directive 065 also allow an applicant to more fully address area-based commingling applications.

V. SUPREME COURT OF CANADA DECISIONS

A. *DUNSMUIR V. NEW BRUNSWICK*[354]

This important decision establishes two standards for review of administrative decisions: correctness and reasonableness. Mr. Dunsmuir was employed by the New Brunswick Department of Justice as a public servant. He was formally reprimanded on several occasions and an employment review meeting was scheduled. In preparing for the meeting, the supervisor and the Assistant Deputy Minister concluded that Dunsmuir was not right for the job, cancelled the meeting, and terminated Dunsmuir without notice but with four months' pay in lieu. Dunsmuir filed a grievance under the *Public Service Labour Relations Act*,[355] which was denied. Dunsmuir then referred the matter to adjudication. The adjudicator found in Dunsmuir's favour, reinstating his employment and finding that he was owed an eight month notice period. The Court of Queen's Bench and Court of Appeal both applied different standards and analyzed the situation differently.

In response to years of confusion by the lower courts in applying judicial review principles, the Supreme Court of Canada decided that a simplification was needed. The Court took the three standards of review (patent unreasonableness, reasonableness *simpliciter*, and

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348 *Ibid.* at 1.

349 ERCB, Directive 065, "Resources Applications for Conventional Oil and Gas Reservoirs" (3 July 2007), <http://www.ercb.ca/docs/Documents/directives/Directive065.pdf> [ERCB Directive 065].

350 *Supra* note 178.

351 *Supra* note 349, s. 3.1.6.2.

352 AEUB, Bulletin 2006-38, "Implementation of Development Entities for Management of Commingled Production from Two or More Pools in the Wellbore" (31 October 2006), online: ERCB <http://www.ercb.ca/docs/documents/bulletins/Bulletin-2006-38.pdf>.

353 *Ibid.* at 7.

354 2008 SCC 9, [2008] 1 S.C.R. 190 [*Dunsmuir*].

355 R.S.N.B. 1973, c. P-25.

correctness) and collapsed them into two standards: reasonableness and correctness. The correctness standard was unchanged and existing jurisprudence applying the correctness standard is still valuable as a precedent. The new reasonableness standard encompasses patent unreasonableness and reasonableness *simpliciter*; where either of those standards would have been applied before, we now simply ask if the decision being reviewed was reasonable, keeping in mind the context and the degree of deference that may be owed. Reasonableness, the Court indicated, is a question of "justification, transparency and intelligibility within the decision-making process. But it is also concerned with whether the decision falls within a range of possible, acceptable outcomes which are defensible in respect of the facts and law."[356]

Instead of the old "pragmatic and functional approach," the new test to be applied is called the "standard of review analysis."[357] The courts should first look to the existing case law first, instead of blindly applying the enumerated factors from the old "pragmatic and functional" test. If the existing case law has already gone through an analysis in similar circumstances, that standard of review can simply be used. Only if the question has not already been considered is it necessary to apply the factors of the standard of review analysis. The Court lists four factors to consider in the standard of review analysis: "(1) the presence or absence of a privative clause; (2) the purpose of the tribunal as determined by interpretation of enabling legislation; (3) the nature of the question at issue, and; (4) the expertise of the tribunal."[358] Within the "nature of the question" analysis, if the question is a question of law, the Court seems to have identified some sub-factors: (1) whether the question is of "central importance to the legal system as a whole and outside the adjudicator's specialized area of expertise" (in which case it should be reviewed based on a correctness standard);[359] and (2) if the question of law is interpreting the enabling statute of the administrative body, which it has experience in interpreting, more deference may be owed.[360] The Court also listed factors that pointed towards a reasonableness standard: (1) a privative clause;[361] (2) a question of fact, discretion or policy;[362] (3) a question where legal issues are intertwined with factual issues;[363] and (4) particular expertise of the tribunal.[364] Constitutional questions regarding division of powers or determinations of true questions of jurisdiction or *vires*, point towards a correctness standard.[365]

356 *Supra* note 354 at para. 47.
357 *Ibid.* at para. 63.
358 *Ibid.* at para. 64. These four factors are slightly different than those from *Pushpanathan v. Canada (Minister of Citizenship and Immigration)*, [1998] 1 S.C.R. 982. In that case, it was the purpose of the enabling legislation and the specific *provision*, rather than the purpose of the *tribunal* that the Court listed as a factor for consideration.
359 *Dunsmuir*, *ibid.* at para. 60, citing *Toronto (City of) v. Canadian Union of Public Employees (C.U.P.E.), Local 79*, 2003 SCC 63, [2003] 3 S.C.R. 77 at para. 62.
360 *Dunsmuir, ibid.* at para. 54.
361 *Ibid.* at para. 52.
362 *Ibid.* at para. 53.
363 *Ibid.*
364 *Ibid.* at para. 54.
365 *Ibid.* at para. 59.

On reviewing the facts in this case, the Supreme Court of Canada applied a standard of review of reasonableness. The Court applied this standard due to a full privative clause, the specialized nature of the regime and the expertise of labour arbitrators, and the question of law not being one of central importance to the legal system or outside the expertise of the adjudicator.