RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO ENERGY LAWYERS

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The purpose of this article is to highlight and discuss legislative and regulatory developments relevant to energy lawyers, including electricity matters, and related jurisprudence that have arisen during the 12-month period from May 2010 to April 2011. This article focuses primarily on decisions before the relevant courts and tribunals in the areas of facilities, tolls and tariffs, the duty to consult, jurisdictional issues, review and variance decisions, surface rights, and standing decisions. In addition, this paper highlights developments in legislation, policy, and guidelines.

Cet article a pour but de souligner et de discuter des développements législatifs et réglementaires qui intéressent les avocats du milieu de l'énergie, notamment les questions d'électricité ainsi que la jurisprudence connexe établie au cours des 12 mois de mai 2010 à avril 2011. Ce document traite essentiellement des décisions des tribunaux pertinents dans les domaines des installations, des droits et tarifs, du droit de consulter, des questions juridictionnelles, des révisions et décisions de variance, des droits de surface, et des décisions ayant qualité de contester. En outre, ce document souligne les développements sur le plan de la législation, la politique, et les directives.

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I. FACILITIES

A. ALBERTA COURT OF APPEAL

1. *BIG LOOP CATTLE LTD V ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*[1]

This decision considers: (1) the importance of putting forward evidence regarding alternate routes for a project; (2) adequate consultation; and (3) characterization of a First Nations Reserve as an urban centre, which would require a 1.5 km setback. We discuss the significance of the First Nations Reserve designation matter.

a. Application

The applicants[2] sought leave to appeal an Energy Resources Conservation Board (ERCB) decision[3] approving Petro-Canada Corporation's (Petro-Canada, now Suncor Energy Inc's) application for a licence to drill 11 gas wells, construct a multi-well gas battery (the central facility), and build a gathering system of pipelines and a trunk line (the Suncor Project).[4]

b. Background

The Suncor Project involved the production and transportation of level three sour gas. Affected areas included the Stoney Nakoda/Eden Valley Reserve (the Reserve).

The applicants sought leave to appeal on several grounds, including that the ERCB erred by failing to characterize the Reserve as an urban centre, which would then have required a

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1 2010 ABCA 328, 490 AR 24 [*Big Loop Cattle*].
2 The applicants were primarily interveners with ranching operations, the Municipal District of Ranchland No 66, and the Stoney Nakoda Nation.
3 *Petro-Canada: Applications for Eleven Well Licences, One Multiwell Gas Battery Licence, and Two Pipeline Licences — Sullivan Field*, ERCB Decision 2010-022 (8 June 2010) [Decision 2010-022]. For a review of this decision see the discussion commencing at Part I.D.1, below. All ERCB decisions can be found online: ERCB <http://www.ercb.ca>.
4 *Big Loop Cattle, supra* note 1 at para 1.

1.5 km setback from the trunkline, pursuant to *Directive 056: Energy Development Applications and Schedules*.[5]

The Reserve has approximately 100 homes and 650 residents. Years prior to the hearing, ERCB staff determined that the Reserve "was not an urban centre because its density was less than eight residences per quarter section."[6] The applicants unsuccessfully challenged this designation at the hearing, the result of which is that a portion of the trunkline "carrying sour gas will be within 320 metres of the boundary of the … Reserve and approximately 500 metres from the closest permanent dwelling."[7] The ERCB did impose a "shelter in place" condition, requiring Suncor to visit each dwelling on the Reserve and ensure that there is a satisfactory room "to provide shelter in the event of the escape of sour gas."[8]

The Alberta Court of Appeal considered the definitions in Appendix 3 of *Directive 056* of "urban centre" and "unrestricted country development" relative to the size of the Reserve. The Court also considered the proximity of the Suncor Project, and in particular the sour gas trunkline, to the Reserve.

c. Key Findings

The Court found that the contention that the ERCB made an error of law in its interpretation and application of the definitions contained in *Directive 056* raises a question of law that is prima facie meritorious. This ground satisfied the test for leave because of "the significance of this designation for the project, and for future applications."[9]

d. Decision

Leave to appeal was granted on the question of whether the ERCB erred by failing to characterize the Reserve as an urban centre, and was denied on all other grounds.[10] As of 26 May 2011, no appeal decision has yet been rendered for this matter.

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5 ERCB, *Directive 056: Energy Development Applications and Schedules* (Calgary: ERCB, 2008) [*Directive 056*].

6 *Big Loop Cattle*, *supra* note 1 at para 15.

7 *Ibid*.

8 *Ibid*.

9 *Ibid* at para 17.

10 *Ibid* at paras 49-50.

B. FEDERAL ENVIRONMENT (CANADIAN ENVIRONMENTAL ASSESSMENT AGENCY)

1. FEDERAL GOVERNMENT APPROVAL OF THOMPSON CREEK METALS' MOUNT MILLIGAN GOLD/COPPER MINE PROJECT[11]

Of interest in this decision is the fact that a proposed mining operation was allowed to dispose of mine wastes into a natural water body as long as the implementation of a Fish Habitat Compensation Plan ensured no net loss of fish habitat.[12]

a. Application

Thompson Creek Metals Company[13] sought approval at both the federal and provincial levels for its Mount Milligan Project, a gold copper mine in northwestern British Columbia (the Mount Milligan Project). When complete, the Mount Milligan Project will include an open pit mine, processing plant, and associated infrastructure.

b. Background

The mine is projected to produce approximately 60,000 tonnes per day of ore and "an estimated 52 million tonnes of potentially acid generating waste rock and tailings" over a projected 15-year mine life.[14]

c. Key Findings

The *Comprehensive Study Report Pursuant to the* Canadian Environmental Assessment Act[15] specifically examined potential effects on fish and fish habitat associated with the tailings impoundment area. It was found that the effects could be mitigated through the implementation of a Fish Habitat Compensation Plan and a recycling program for the effluent to reduce the use of freshwater and to minimize the creation of mining effluent.

The deposit of mine wastes into a natural water body was permitted in this case, with strict conditions, because the Environmental Assessment (EA) process determined that it was the

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11 Environment Canada, News Release, "Government of Canada Announces Decisions on Mount Milligan and Prosperity Gold-Copper Mines" (2 November 2010), online: Environment Canada <http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=59F03FA9-63AD-4EED-A14F-04BBF32906CF> ["Milligan and Prosperity"]. Originally it was approved by the Federal Minister of the Environment on 1 December 2009: Canadian Environmental Assessment Agency (CEAA), "Environmental Assessment Decision Statement: Mount Milligan Gold-Copper Mine" (1 December 2009), online: CEEA <http://www.ceaa.gc.ca/050/document-eng.cfm?document=39731>.

12 Environment Canada, "Backgrounder: Mount Milligan," online: Environment Canada <http://www.ec.gc.ca/default.asp?lang=En&n=714D9AAE-1&news=E8C75DB6-CE1E-455E-8C87-A4509A6F414A> ["Milligan Backgound"].

13 Thompson Creek Metals Company acquired Terrane Metals Corp in October 2010. Thompson Creek Metals Co News Release, "Thompson Creek Metals Company Inc. and Terrane Metals Corp. Announce Commencement of Closing of the Previously Announced Plan of Arrangement" (20 October 2010), online: Thompson Creek Metals Company <http://www.thompsoncreekmetals.com/s/News_Releases.asp?ReportID=424036>.

14 "Milligan Background," *supra* note 12.

15 Fisheries and Oceans Canada and Natural Resources Canada, *Comprehensive Study Report Pursuant to the* Canadian Environmental Assessment Act (18 September 2009), online: CEAA <http://www.ceaa.gc.ca/050/document-eng.cfm?document=38855>.

"most environmentally, technically and socio-economically sound method" for disposing of the Mount Milligan Project's mine waste.[16] Effluent from the Mount Milligan Project's tailings impoundment areas must still comply with the requirements of the *Metal Mining Effluent Regulations*,[17] including the limits on releases of lead and arsenic.[18]

d. Decision

On 2 November 2010, the federal government granted the Mount Milligan Project the necessary federal authorizations to proceed.

2. FEDERAL GOVERNMENT DENIAL OF TASEKO MINES LTD'S PROSPERITY GOLD-COPPER MINE PROJECT[19]

Of significance in this decision is the finding that in combination with past, present, and reasonably foreseeable future projects, the approval of this project would result in a significant adverse cumulative effect on fish and fish habitat. This finding resulted in denial of the application, an outcome of note to any facility regulatory lawyer.

a. Application

Taseko Mines Ltd (Taseko) applied at the federal and provincial levels for approval of a large open pit gold-copper mine, to be constructed 125 km southwest of Williams Lake, British Columbia (the Prosperity Mine Project).

b. Background

In addition to the open pit mine, the Prosperity Mine Project would have included an onsite mill and other infrastructure. The mine site would have covered a 35 km^2 area in the Fish Creek watershed, which drains into the Taseko River, and includes Fish Lake and Little Fish Lake. The proposed tailings impoundment area would have necessitated the destruction of both of these lakes, as well as portions of Fish Creek, which are all natural fish-bearing water bodies.[20]

16 "Milligan Background," *supra* note 12.
17 SOR/2002-222.
18 "Milligan Background," *supra* note 12.
19 "Milligan and Prosperity," *supra* note 11; CEAA, *Government of Canada Response to the Report of the Federal Review Panel for the Taseko Mines Limited's Prosperity Gold-Copper Mine Project in British Columbia* (2 November 2010), online: CEAA <http://www.ceaa.gc.ca/052/document-html-eng.cfm?did=46183> [*Taseko Project*].
20 *Ibid*. In spite of these issues, the project received the provincial EA Certificate from the Province of British Columbia in January 2010. British Columbia Environmental Assessment Office, *Environmental Assessment Certificate #M09-02* (14 January 2010), online: British Columbia <http://a100.gov.bc.ca/appsdata/epic/html/deploy/epic_document_6_31890.html>. The revised proposal, resubmitted to the federal government in February 2011, attempts to address these concerns, preserving Fish Lake and its aquatics. Taseko Mines Ltd, News Release, "Taseko Mines Submits Revised Project Description for the Prosperity Project to Federal Government" (21 February 2011), online: Taseko Mines Ltd <http://www.tasekomines.com/tko/NewsReleases.asp?ReportID=443722>.

c. Key Findings

The federal government found that federal authorizations could not be granted for the proposal due to concerns about the significant adverse environmental effects.

The Federal Prosperity Review Panel released its report on 2 July 2010 and concluded that

> the Project would result in significant adverse environmental effects on fish and fish habitat, on navigation, on the current use of lands and resources for traditional purposes by First Nations and on cultural heritage, and on certain potential or established Aboriginal rights or title. The Panel also concludes that the Project, in combination with past, present and reasonably foreseeable future projects would result in a significant adverse cumulative effect on grizzly bears in the South Chilcotin region and on fish and fish habitat.[21]

d. Decision

On 2 November 2010 the federal government denied Taseko's application for the Prosperity Mine Project as proposed.[22]

C. NATIONAL ENERGY BOARD

1. *NOVA GAS TRANSMISSION LTD: APPLICATION DATED 19 FEBRUARY 2010 FOR THE HORN RIVER PROJECT*[23]

This decision sets out the factors that the National Energy Board (NEB) will consider in approving the acquisition and operation of existing NEB-regulated facilities and the approval of the construction and operation of additional new connected facilities.

a. Application

NOVA Gas Transmission Ltd (NGTL) applied to the NEB to construct and operate the Horn River Project. As part of its application, NGTL requested: (1) leave, pursuant to section 74 of the *National Energy Board Act*[24] to acquire the Ekwan Pipeline Assets from Encana Corporation (Encana); (2) a Certificate of Public Convenience and Necessity (CPCN), to be issued pursuant to section 52 of the *NEB Act* authorizing the construction and operation of

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21 Federal Review Panel, *Report of the Federal Review Panel: Prosperity Gold-Copper Mine Project Taseko Mines Ltd. — British Columbia* (Ottawa: CEAA, 2010) at ii, online: CEAA <http://www.ceaa/gc.ca/052/document-eng.cfm?did=46911>. "The federal Prosperity Review Panel … was appointed on January 19, 2009 by the Minister of the Environment, the Honourable Jim Prentice, to conduct a review of Taseko's Project" (*ibid* at i). The public hearings took place over approximately two months and were attended by approximately 2,700 parties (*ibid* at 6).

22 It was left open to Taseko, however, to redesign the Prosperity Mine Project and reapply for federal approval. *Taseko Project, supra* note 19. On 21 February 2011, Taseko resubmitted its redesigned proposal to the federal government for approval. See *supra* note 20. For a further update on the status of the Prosperity Mine Project, see Taseko Mines Ltd, "Properity," online: Taseko Mines Ltd <http://www.tasekomines.com/tko/prosperity.asp>.

23 *Reasons for Decision: NOVA Gas Transmission Ltd.*, NEB Decision GH-2-2010 (27 January 2011) [*Horn River Project*]. All National Energy Board (NEB) decisions can be found online: NEB <http://www.neb-one.gc.ca>.

24 RSC 1985, c N-7 [*NEB Act*].

the Horn River Facilities;[25] and (3) authorization, pursuant to section 59 of the *NEB Act*, to include the purchase price of the Ekwan Pipeline Assets plus adjustments in the Alberta System[26] rate base.

NGTL amended its application to request an order, pursuant to section 58 of the *NEB Act*, exempting NGTL from the requirements of section 33 of the *NEB Act* for the Komie East Extension[27] and the construction camp of the Horn River Project.

b. Background

The Horn River Project is a proposed pipeline extension of NGTL's Alberta System on its Northwest Mainline to two natural gas processing facilities, the Cabin Gas Plant, and the Fort Nelson North Gas Plant. The Horn River Project transports sweet natural gas and provides customers direct access to the NGTL Inventory Transfer market.

c. Key Findings

The NEB made the following findings: (1) NGTL demonstrated that there was an adequate gas supply; (2) there are sufficient markets; (3) the application was for the correct capacity; (4) NGTL's parent company, TransCanada PipeLines Ltd (TransCanada), has the ability to finance the Horn River Project construction and to place it in service; (5) "the Horn River Project would result in an overall benefit to the Alberta System toll payers";[28] (6) the general design is appropriate for its intended use; (7) NGTL's consultation program was appropriate; (8) the Horn River Project "would not negatively impact the use of lands and resources for traditional purposes";[29] (9) NGTL's route selection process was reasonable; (10) subject to the *Environmental Screening Report* (*ESR*)[30] recommendations becoming conditions of approval, the Horn River Project is not likely to cause significant adverse environmental effects; (11) despite Environment Canada's (EC's) suggestion that NGTL's cumulative effects assessment should include consideration of likely development scenarios,[31] NGTL's assessment was sufficient; (12) NGTL considered and addressed all socio-economic aspects

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25 *Horn River Project*, *supra* note 23 at x. The Horn River Project consists of two primary components; the acquisition and operation of the NEB-regulated Ekwan Pipeline from Encana, and the construction and operation of approximately 74 km of pipeline and metering facilities (*ibid* at 1).

26 The Alberta System is an integrated natural gas pipeline system, comprised of approximately 24,000 km of pipeline and associated compression and other facilities, owned by TransCanada PipeLines Ltd (TransCanada) (owner of NGTL). This system transports gas produced in the Western Canadian Sedimentary Base. Global Gas Transport, "TransCanada: Gaining Strength by nurturing a focused portfolio [free access]" (1 July 2010), online: Global Gas Transport <http://globalgastransport.info/archive.php?id=683>.

27 Approximately "2.2 km of 610 mm … [outside diameter] sweet natural gas pipeline, extending northeast from a point on the Cabin Section to the … Komie East meter station" was proposed as part of the Horn River Facilities. *Horn River Project*, *supra* note 23 at 74.

28 *Ibid* at 17.

29 *Ibid* at 32.

30 *Ibid*, Appendix IV. The *ESR* is a report prepared by the NEB as part of its responsibilities under the *Canadian Environmental Assessment Act*, SC 1992, c 37 [*CEA Act*]. The *ESR* identified potential adverse environmental and socio-economic effects of the Horn River Project and proposed a number of protection procedures and mitigation measures to be implemented by NGTL. In its analysis and recommendations, the NEB considered information provided by NGTL, federal authorities, Aboriginal groups, other interested parties, and the public.

31 This would include "potential well densities, supporting infrastructure (both exploratory and production), and their associated anticipated effects assessed over a five- to 20-year time horizon." *Horn River Project*, *ibid* at 37.

of the Horn River Project and proposed suitable mitigation; (13) the Horn River Project will have positive economic benefits and no negative effect on infrastructure and service delivery in the Horn River Project area;[32] and (14) the economic justification provided by NGTL for the acquisition of the Ekwan Pipeline Assets was reasonable.

The NEB required the following from NGTL: (1) submission of a construction safety manual, construction schedule, and construction progress reports; (2) completion of a hydrostatic pressure test; and (3) additional requirements for mitigation and monitoring of boreal woodland caribou habitat.

In addition, the NEB stated: (1) "[A]dverse impacts on the Alberta [natural gas liquid (NGL)] industry that might result from recent and future facility applications is beyond the scope of the GH-2-2010 proceeding";[33] (2) changes to contractual terms for Firm Transportation — Receipt (FT-R) service on the Horn River Project, as advocated by the Western Export Group (WEG), were outside the scope of the proceeding;[34] (3) NGTL should provide its key supply/demand data as part of its application filings (and not only after several rounds of information requests) to "enhance the efficiency of the application review process";[35] (4) with the exception of NGTL's request to include the purchase price of the Ekwan Pipeline Assets in the Alberta System rate base, "matters relating to NGTL's toll methodology are outside the scope of this proceeding";[36] (5) in any future applications, the NEB "expects NGTL to identify and describe, to the extent possible, the treatment of potential future incremental facilities that may be required to complement an applied-for project";[37] (6) NGTL's efforts to consult and enter into long-term agreements with Aboriginal groups that support economic development of the Horn River Project indicates its commitment to establish long-term collaborative relationships; and (7) NGTL will be required to file an updated Caribou Protection Plan, a Caribou Habitat Restoration Plan, and "a plan which describes measures to offset unavoidable and residual impacts to boreal woodland caribou habitat within the Footprint" of the Horn River Project.[38]

The NEB noted NGTL's submissions that "the Section 58 Activities take place entirely on provincial Crown land, and that the [British Columbia] Integrated Land Management Bureau has no objection to the Section 58 Activities."[39] The NEB held that, upon approval, NGTL will be exempted, pursuant to section 58, from the requirement to file a Plan, Profile and Book of Reference (PPBoR) for the section 58 activities.[40] Effective upon issuance of a CPCN, the NEB will issue an order exempting NGTL from sections 31(c), 31(d), and 33 of the *NEB Act*, and impose further conditions related to section 58 activities.[41]

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32 *Ibid* at 40.
33 *Ibid* at 11.
34 *Ibid* at 13.
35 *Ibid*.
36 *Ibid* at 17.
37 *Ibid*.
38 *Ibid* at 36. The scope of the term "offset" "does not include activities that require land acquisition, replacement or substitution of habitat, habitat compensation, terrestrial no-net-loss measures or the regional application of mitigation strategies" (*ibid* at 38).
39 *Ibid* at 41. "Section 58 Activities" were defined as "[t]he proposed clearing and construction of the Komie East Extension and the Project construction camp site in the winter of 2010/2011" (*ibid* at viii).
40 *Ibid* at 42. A PPBoR is normally required under section 33 of the *NEB Act*.
41 *Ibid*. See list of these conditions.

d. Decision

The application was approved, and the Horn River Project was found to be in the public interest.

2. THE MACKENZIE GAS PROJECT[42]

This is a summary of the long-awaited Mackenzie Gas Project decision, a decision rendered more than six years after the filing of the application.

a. Application

In October 2004, the NEB received an application for the construction and operation of the Mackenzie Gas Project (the Mackenzie Gas Project), requesting the following: (1) approval for the development of three natural gas fields,[43] pursuant to section 5.1 of the *Canada Oil and Gas Operations Act*;[44] (2) authorization to carry on work and activity in respect of the Mackenzie Gathering System, including upstream gathering pipelines, the Inuvik Area Facility (Inuvik Facility), and a NGL, all under section 5(1)(b) of the *COGOA*; (3) a CPCN authorizing the construction and operation of the Mackenzie Valley Pipeline[45] and associated facilities, to be issued pursuant to section 52 of the *NEB Act*; and (4) approval, pursuant to Part IV of the *NEB Act*, of the toll and tariff principles that were to apply to service on the Mackenzie Valley Pipeline.

b. Background

The Mackenzie Gas Project, as proposed, "would be the largest industrial development in Canada's North."[46] The Mackenzie Gas Project "would be built over four years and cost about $16 billion."[47] The proponents identified 32 communities in the Northwest Territories and in northwestern Alberta that could be affected by the Mackenzie Gas Project.[48]

Natural gas produced at Niglintgak, Taglu, and Parsons Lake would be shipped through the upstream gathering pipelines to the Inuvik Facility. At the Inuvik Facility, the raw natural gas would be separated into marketable natural gas and NGLs. Marketable natural gas would be transported via the Mackenzie Valley Pipeline to northwestern Alberta and on to southern markets.[49] NGLs would be transported through the NGL pipeline to Norman Wells, "where it would connect to the existing Enbridge Pipelines (NW) Inc. Norman Wells Pipeline."[50]

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42 *Reasons for Decision*: *Mackenzie Gas Project*, NEB Decision GH-1-2004, vols 1 & 2 (16 December 2010) [*Mackenzie Decision*].
43 The Niglintgak, Taglu, and Parsons Lake gas fields.
44 RSC 1985, c O-7 [*COGOA*].
45 The Mackenzie Valley Pipeline is a 1,196 km long, 750 mm diameter pipeline carrying natural gas from the Inuvik Facility to northwestern Alberta (the Mackenzie Valley Pipeline). *Mackenzie Decision*, vol 2, *supra* note 42 at 9-10.
46 *Mackenzie Decision*, vol 1, *supra* note 42 at 16.
47 *Ibid* at 5.
48 *Mackenzie Decision*, vol 2, *supra* note 42 at 16.
49 *Mackenzie Decision*, vol 1, *supra* note 42 at 45.
50 *Mackenzie Decision*, vol 2, *supra* note 42 at 6.

c. Key Findings

The NEB reached its decision based on the following key findings: (1) the Mackenzie Valley Pipeline "is, and will be, required by present and future public convenience and necessity" provided the terms and conditions outlined in the NEB's decision are met;[51] (2) "the Mackenzie Gathering System promotes safety, environmental protection and conservation of oil and gas resources";[52] (3) the general approach, conceptual design, and plan presented for the development of the natural gas fields are satisfactory; (4) augmenting the "supply of natural gas, a relatively clean-burning and efficient fuel source," would benefit the Canadian public;[53] (5) the proponents have shown that there are sufficient natural gas resources in and around the Mackenzie Delta to supply the Mackenzie Gas Project, and that there is a large enough market to use the gas; (6) the Mackenzie Gas Project's economic benefits would be large, providing a significant increase in Canada's gross domestic product and generated labour income during its years of operation;[54] (7) the proponents are fully capable to design, construct, and operate the facilities despite the engineering challenges in the north such as thaw settlement, earthquakes, and slope instability; (8) the general routes of the proposed pipelines are appropriate; (9) the evidence demonstrates that the proponents will be able to finance the Mackenzie Gas Project; (10) the proposed use of a lifespan engineering approach for the Mackenzie Gas Project that includes construction mitigation and operational monitoring is acceptable; (11) the NEB accepted the proponents' proposal that "tolls be established based on the best estimate of the Mackenzie Valley Pipeline's costs for the coming year";[55] (12) the proponents' initial two-zoned tolling method is approved; (13) the proponents' minimum 15-year term toll contract, for financing requirements, is accepted; (14) the Mackenzie Gas Project's Consultation Program was effectively designed and implemented; and (15) northerners would benefit from the opportunity to use natural gas in their communities.

In assessing the environmental and socio-economic effects of the Mackenzie Gas Project, the NEB extensively relied on the Joint Review Panel Report.[56] The NEB made the following specific findings relating to environmental and socio-economic matters: (1) the commitments made by the proponents under the *Mackenzie Gas Project Socio-Economic Agreement*[57] signed with the Government of the Northwest Territories, in addition to the conditions imposed by the NEB, would adequately address concerns raised by residents of the Northwest Territories, such as employment needs and harvester compensation; (2) at this point, it is not possible to associate the Mackenzie Valley Pipeline to any particular

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51 *Ibid* at 216.

52 *Ibid*.

53 *Ibid* at 31.

54 *Mackenzie Decision*, vol 1, *supra* note 42 at 76-77.

55 *Mackenzie Decision*, vol 2, *supra* note 42 at 172.

56 In 2004 the Minister of the Environment, in agreement with the Chairs of both the Mackenzie Valley Environmental Impact Review Board and the Inuvialuit Game Council appointed the Joint Review Panel for the Mackenzie Gas Project. Joint Review Panel for the Mackenzie Gas Project, *Foundation for a Sustainable Northern Future: Report of the Joint Review Panel for the Mackenzie Gas Project* (Ottawa: Government of Canada, 2010).

57 To address concerns of mutual interest, the proponents and the Government of the Northwest Territories signed a *Socio-Economic Agreement*, intended to optimize beneficial opportunities and mitigate negative impacts arising from the project to its residents. *Mackenzie Gas Project Socio-Economic Agreement* (January 2007), online: Government of the Northwest Territories, (Industry, Tourism and Investment) <http://www.iti.gov.nt.ca/Publications/2007/miningoilgas/070119_GNWT-MGP_SEA_Final_Signed.pdf>.

downstream facility that would use the gas transported by the Mackenzie Gas Project and therefore, the environmental effects arising from the operation of downstream facilities are not relevant to the application;[58] (3) the proponents' climate change estimates used in the design are acceptable; and (4) government departments, such as EC and Indian and Northern Affairs Canada (INAC), should be consulted, so the proponents can "benefit from their expertise for the field design."[59]

The NEB made a number of requests to the proponents, including to: (1) provide laterals to the communities upon request, as long as certain economic conditions are met; (2) make gathering and transmission pipelines "open access"; (3) consider the use of upper limit temperature scenarios in design assessments, given the uncertainty related to climate change predictions; (4) submit Wildlife Protection and Management Plans prior to filing the Mackenzie Gas Project's detailed route; (5) demonstrate that the necessary long-term transportation service contracts have been executed before construction starts; (6) implement an Environmental Protection and Monitoring and Surveillance Program;[60] (7) consider, in the future, additional tolling zones; (8) investigate shorter contract terms once the Mackenzie Gas Project becomes operational; and (9) take into account the INAC's concern respecting the effects of changes in ground thermal regime due to possible addition of compressor stations.

In addition, the NEB stated that: (1) approval of the applications for the Mackenzie Gas Project depended on the proponents meeting the more than 200 conditions imposed;[61] (2) approval for the development of the natural gas fields would "be issued once the proponents have complied with the necessary provisions of the [*COGOA*]";[62] (3) future developments related to the Mackenzie Gas Project, such as the construction of additional compressor stations, would have to be submitted for approval through separate applications;[63] and (4) ongoing compliance assurance reviews, inspections, and audits will be conducted by the NEB from the Mackenzie Gas Project's construction and operation to the time the facilities are no longer needed.[64]

d. Decision

On 16 December 2010 the application was approved. The NEB found that the Mackenzie Gas Project is in the public interest and that northerners and other Canadians will be better off with the Mackenzie Gas Project's approval.

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58 *Ibid* at 31.
59 *Ibid* at 37.
60 This request is only applicable to Shell Canada Ltd (Shell) and Imperial Oil. *Ibid* at 62, 76.
61 *Mackenzie Decision*, vol 1, *supra* note 42 at 73.
62 *Mackenzie Decision*, vol 2, *supra* note 42 at 216.
63 *Mackenzie Decision*, vol 1, *supra* note 42 at 9.
64 *Ibid* at 78.

3. *WESTCOAST ENERGY INC, CARRYING ON BUSINESS AS SPECTRA ENERGY TRANSMISSION (WESTCOAST): DAWSON PROJECT APPLICATION OF 31 MAY 2010*[65]

This decision relates to the factors that the NEB will consider related to construction and operation of a processing plant and associated facilities and exemptions related to approvals required for operation of existing segments of pipeline.

a. Application

Westcoast Energy Inc[66] (Westcoast) applied to the NEB for approval of the Westcoast Dawson Project (the Dawson Project).

As part of its application, Westcoast requested: (1) authorization, pursuant to section 58 of the *NEB Act*, to construct and operate the Dawson Processing Plant and associated facilities (Dawson Plant), as well as an exemption from the requirements imposed by sections 31 and 47(1) of the *NEB Act*; (2) leave, pursuant to section 74(1)(b) of the *NEB Act*, to purchase a segment of the Bissette Pipeline[67] from Spectra Energy Midstream (Spectra); and (3) an exemption under section 58 of the *NEB Act* from the requirements of section 30 of the *NEB Act*, the effect of which would be to approve the operation by Westcoast of the acquired segment of the Bissette Pipeline.

b. Background

The proposed Dawson Project consists of: (1) the construction and operation of the Dawson Plant; (2) the purchase of a segment (4.1 km long) of the Bissette Pipeline (to be renamed the Willowbrook Pipeline);[68] and (3) the operation of the Willowbrook Pipeline. The Dawson Plant[69] would include the construction and operation of a single train, natural gas processing plant, 1 km of a new 406.4 mm outside diameter natural gas sales pipeline (the Bessborough Pipeline),[70] and other associated infrastructure.

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65 NEB Hearing Order GH-3-2010 regarding Westcoast Energy Inc carrying on business as Spectra Energy Transmission (Westcoast) — Dawson Project, Letter from Anne-Marie Erickson to Garth Johnson and Peter Spicker (31 January 2011) [Letter Decision].

66 Carrying on business as Spectra Energy Transmission.

67 The Bissette Pipeline is a new upstream gathering pipeline for which Spectra received approval to construct and operate from the British Columbia Oil & Gas Commission (BCOGC) (the Bissette Pipeline). Letter Decision, *supra* note 65 at 2. Following the oral portion of the hearing, Westcoast advised that Spectra expects the Bissette Pipeline to be in service in late March or early April 2011 (*ibid* at 10).

68 *Ibid* at 2.

69 "The Dawson Plant would be located approximately 16 km west of the City of Dawson Creek, British Columbia." *Ibid* at 1.

70 *Ibid* at 1. Raw gas would be delivered to the Dawson Plant through the Bissette Pipeline (segment owned by Spectra) and processed into sales gas. The sales gas would then be transported through the Bessborough Pipeline to the NGTL Groundbirch Pipeline (*ibid*). The Willowbrook Pipeline (downstream of the Dawson Plant) "would be used by Westcoast to deliver blended raw gas from the Dawson Plant to the Westcoast McMahon processing plant through the South Peace Pipeline, as the Dawson Plant does not include acid gas disposal or sulphur recovery facilities" (*ibid* at 2).

c. Key Findings

The NEB made the following key findings: (1) purchase of the Willowbrook Pipeline is necessary in order for Westcoast "to have access to a means of disposing of the acid gas recovered at the Dawson Plant";[71] (2) the Dawson Plant is needed and economically feasible; (3) Westcoast demonstrated that "adequate supply, markets, and contractual commitments exist to support the Project";[72] (4) Westcoast's public consultation and Aboriginal engagement programs provided adequate participation opportunity for those who could potentially be affected by the Dawson Project; (5) the Dawson Project is not likely to cause significant adverse environmental and socio-economic effects provided mitigation measures are implemented according to the NEB's determinations in the Environmental Screening Report (ESR); (6) the Dawson Project would be constructed using proven modern design, manufacturing, and coating practices, therefore minimizing the occurrence of integrity-related defects during operation;[73] (7) exemption from section 47 of the *NEB Act*, "in respect of leave to open for certain utility piping systems," would not compromise the safety of the public or workers;[74] and (8) the motion of the South Dawson Landowners Committee/Canadian Association of Energy and Pipeline Landowner Association[75] should be addressed through a separate process.

The NEB's refusal to grant leave for the operation of the Willowbrook Pipeline was premised on the NEB's conclusion that an "accurate description of the Willowbrook Pipeline could only be made available once construction is completed."[76] In addition, the NEB maintained that it lacked crucial information related to the Willowbrook Pipeline, such as: (1) "the residual effects from the construction of the Willowbrook Pipeline and any post-construction monitoring requirements identified through the BCOGC approval process"; (2) "confirmation that Spectra applied for and received approval for leave to open the Bissette Pipeline from the BCOGC"; and (3) "any commitments and conditions imposed by the BCOGC on the leave to open approval."[77]

In addition, the NEB stated the following: (1) the conditions in the ESR will be included in any approvals the NEB may issue; (2) Westcoast must submit construction and operation manuals, to facilitate the ongoing review by the NEB of the safety plans and performance;[78] and (3) Westcoast is encouraged "to periodically evaluate opportunities for reducing greenhouse gas [(GHG)] emissions, including the use of hydroelectric power."[79]

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71 *Ibid* at 11.
72 *Ibid* at 4.
73 *Ibid* at 9.
74 *Ibid* at 10. The Dawson Processing Plant and Associated Facilities will also be exempted from sections 30(1)(a) and 31 of the *NEB Act* (*ibid* at 13).
75 A motion requesting the NEB "to make a declaratory order stating that the proposed Bissette Pipeline is properly within federal jurisdiction" and, hence, subject to regulation by the NEB. *Decision on Notice of Motion from the South Dawson Landowner Committee/Canadian Association of Energy and Pipeline Landowner Associations Regarding the jurisdiction of the Bissette Pipeline*, NEB File OF-Fac-PipeGen-W102-01 (7 January 2011) at 1.
76 Letter Decision, *supra* note 65 at 12.
77 *Ibid*. The NEB, however, encouraged Westcoast to reapply for the operation of Willowbrook Pipeline "after the Bissette Pipeline is fully constructed and is in service" (*ibid* at 13).
78 *Ibid* at 9.
79 *Ibid*.

d. Decision

The application was approved. Application for leave to operate the Willowbrook Pipeline, however, was declined, since the NEB did not have sufficient information to grant this leave.

D. ENERGY RESOURCES CONSERVATION BOARD

1. *PETRO-CANADA: APPLICATIONS FOR ELEVEN WELL LICENCES, ONE MULTIWELL GAS BATTERY LICENCE, AND TWO PIPELINE LICENCES — SULLIVAN FIELD*[80]

Of interest in this decision are the ERCB's findings related to a project proponent's obligations in considering alternate pipeline routes, and the extent to which a project proponent should consult with landowners in this regard.

a. Application

Petro-Canada submitted 11 gas well applications, one multiwell gas battery application, and a pipeline application whereby one pipeline would transport sour gas and the other would transport fuel gas (the PC Project).

b. Background

The purpose of the wells was to obtain gas production from the Rundle Group. The wells would contain sour gas. The ERCB received objections from a number of individuals.[81] Given the PC Project's proximity to Kananaskis and the Eastern Slopes region, the objectors' concerns related to the environment, the impact of development on this unique region, and Petro-Canada's public consultation program.

Numerous procedural and interlocutory motions and requests were filed between 16 April 2008 and the start of the hearing on 12 November 2008. The hearing lasted almost three months, concluding on 30 January 2009.

c. Key Findings

The ERCB found that there was a need for the PC Project and that the public consultation requirements had been met. The consultation met the ERCB's *Directive 056* requirements and included the more onerous public consultation requirements outlined in the ERCB Informational Letter IL 93-09.[82]

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80 Decision 2010-022, *supra* note 3. Note: Leave to appeal this decision was granted by the Alberta Court of Appeal. For a review of the leave to appeal decision, see the discussion of *Big Loop Cattle, supra* note 1, in Part I.A.1, above.

81 These objections came from area landowners, residents, grazing lease and allotment holders, outfitters and guides, ranchers, the Municipal District of Ranchlands No 66, and wilderness camp and campground operators. *Ibid* at 3.

82 ERCB, Informational Letter IL 93-09, "Oil and Gas Developments Eastern Slopes (Southern Portion)" (13 December 1993) [IL 93-09].

A more extensive consultation before the hearing regarding the reasons for Petro-Canada's rejection of the alternative route options would have made the process more efficient, given the interveners' arguments that Petro-Canada had not engaged the public on the question of alternative routes for the trunk line and that the PC Project would be located on traditional lands of the Stoney Nakoda Nation.

With respect to route and site selection, the ERCB found that: (1) taking into account the geology, topography, and other features in the area, the proposed sites were limited. There were no alternative locations put forth by the interveners and the ERCB was satisfied that Petro-Canada had minimized the PC Project footprint to the best degree possible;[83] (2) since the central facility site chosen by Petro-Canada was the preferred option by Alberta Sustainable Resource Development (ASRD), it must be in the acceptable range for disruption to wildlife;[84] and (3) based on all the evidence, the Eden Valley route was the most advantageous, having regard to all important factors.[85] Where circumstances warrant, applicants are expected to consider multiple route options during the initial phases to determine the best route, which had occurred in this case.

With respect to environmental considerations, the ERCB: (1) was satisfied that Petro-Canada had assessed the watercourse crossings in appropriate detail, by taking into account water supply, water quality, and protection of aquatic habitat; (2) found that there were no specific requirements for vegetation sampling with respect to energy projects;[86] (3) determined that managing access was key to minimizing the grizzly bear mortality risk and required that Petro-Canada work with ASRD to determine wolf activity in the area and monitor any changes in wolf/livestock interactions; (4) found that Petro-Canada's proposed mitigation measures against unauthorized access were reasonable;[87] (5) held that the PC Project, if properly designed and operated, would meet required air quality standards[88] and emissions[89] associated with the PC Project and were not a barrier to approval; (6) required Petro-Canada to submit a revised noise impact assessment (NIA) and a post-commissioning comprehensive sound monitoring survey; and (7) did not agree with the interveners'

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83 Decision 2010-022, *supra* note 3 at 12. Petro-Canada indicated that it had taken great care in reviewing potential site and routing options for the PC Project. The interveners were concerned about the PC Project's impact on Telegraph Trail (a historic trail) and other environmentally sensitive areas.

84 *Ibid* at 15. After extensive consideration of the relevant criteria, the central site option ultimately approved was chosen over four others.

85 These factors include this route: (1) being the shortest; (2) making use of existing linear disturbances; (3) being entirely on Crown land and not requiring third party crossings; (4) making use of a large portion of Petro-Canada's existing fuel gas pipeline right-of-way (ROW); (5) avoiding large contiguous grassland patches; (6) being located on terrain suitable for the proposed pipeline construction methods; (7) having a lower visual impact than alternative routes; (8) potentially affecting fewer land users and residents; and (9) having a shorter length through designated wildlife ranges and integrated resource plan zones and having no impacts that could not "be adequately mitigated to reduce potential effects." *Ibid* at 28. The ERCB also considered that Petro-Canada chose to transport its gas to the Devon Coleman plant after having considered four plant options in great depth, and that after deciding on a plant, Petro-Canada considered six trunk line corridor options.

86 *Ibid* at 65.

87 *Ibid* at 78.

88 *Ibid* at 80. The air quality standards which Petro-Canada must meet are set out in Alberta Environment, *Alberta Ambient Air Quality Objectives* (Edmonton: Alberta Environment, 2011) and *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*, ERCB Directive 060 (16 November 2006) [*Directive 060*].

89 The expected emissions were SO_2, nitrogen oxides, carbon monoxide and, "particulate matter, as well as SO_2 emissions from maintenance and emergency flaring." Decision 2010-022, *supra* note 3 at 80.

argument that it was to consider the potential for this PC Project to induce further development in the area; each Project is to be considered on its own basis.

With respect to socio-economic considerations: (1) the ERCB found no current land-use planning direction in place that would exclude the PC Project area from petroleum development. If, prior to its final decision, a regional land-use plan was implemented, the ERCB would ensure those changes were respected; (2) monitoring and consultation were key to minimizing or eliminating grazing issues, and access management is important with respect to grazing leases; and (3) the ERCB was not willing to put conditions on Petro-Canada regarding further developments, as suggested by the interveners, because such conditions would effectively put a moratorium on development and this was something that could only be done by the Legislature.[90]

With respect to the two questions of constitutional law raised by the Stoney Nakoda Nation,[91] the ERCB concluded that: (1) it was constitutionally competent to make a decision on the application. The legislation is of general application and applies equally to sour gas facilities regardless of proximity to Indian reserves. The legislation does not "impair the status or capacity of Indians," nor does it "single out Indians or Indian reserves for special treatment";[92] and (2) it cannot accept the proposition that, because reserve lands lay within the Emergency Planning Zone (EPZ), federal law was to be applied. In no way was the ERCB encroaching on federal jurisdiction by making determinations concerning the EPZ.

d. Decision

The ERCB granted Petro-Canada's application subject to 15 conditions and based on Petro-Canada's 387 commitments.[93]

2. *SHELL CANADA LIMITED: APPLICATIONS FOR WELL, FACILITY, AND PIPELINES LICENCES — WATERTON FIELD*[94]

In this decision, the ERCB sets out the factors to consider in an application for a well licence and construction and operation of related facilities. This decision also sends a message to industry related to responding to failures and emphasizes the importance of relationships with relevant stakeholders.

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90 *Ibid* at 92, 96.

91 The two constitutional law questions were: (1) whether elements of the *Energy Resources Conservation Act*, RSA 2000, c E-10 [*ERCA*], the *Oil and Gas Conservation Act*, RSA 2000, c O-6 [*OGCA*], and the *Pipeline Act*, RSA 2000, c P-15, which granted the ERCB the jurisdiction to make a decision concerning the PC Project (which was on traditional lands of the Stoney Nakoda Nation), were applicable in light of the Aboriginal and treaty rights held by the Stoney Nakoda Nation and section 35 of the *Constitution Act, 1982*, being Schedule B to the *Canada Act 1982* (UK), 1982, c 11; and (2) whether the location of the Eden Valley Reserve within the Emergency Planning Zone (EPZ) of the proposed PC Project mandates the application of federal law. Decision 2010-022, *supra* note 3 at 98.

92 *Ibid* at 110.

93 *Ibid* at 113-47.

94 *Shell Canada Limited: Application for Well, Facility, and Pipeline Licences — Waterton Field*, ERCB Decision 2011 ABERCB 007 (9 March 2011).

a. Application

Shell applied to the ERCB for a licence to drill a well referred to as the Waterton 68 Well near Waterton, Alberta (the 68 Well). Along with that, it "submitted four related applications to construct and operate two pipelines and one facility and to amend an existing facility licence" (the Waterton Applications).[95]

b. Background

A number of objections related to public safety, the environment, personal impacts, the location of the proposed well, and Shell's operational history were raised. Shell had engaged in the ERCB Appropriate Dispute Resolution program with some of the parties but not all issues were resolved.[96]

The ERCB reviewed Shell's operations and construction history in the area. It discussed the previous failure of the Carbondale System and the steps Shell took as a result. It also reviewed stakeholder concerns regarding emissions and odours between 2002 and 2010.[97]

With respect to some preliminary jurisdictional issues, the ERCB indicated that its jurisdiction in this matter was straightforward and was found in the *ERCA*, the *OGCA*, the *Pipeline Act*, and their regulations. The ERCB has exclusive jurisdiction to approve or deny a project. The ERCB considers whether a project "is in the public interest having regard to social, economic, and environmental effects of the project."[98]

c. Key Findings

With respect to the well application, the ERCB accepted the need for the 68 Well and the fact that "Shell had the right to explore for the resource."[99]

The ERCB accepted Shell's commitments that during drilling and completion, the site would be manned continuously, allowing for timely detection of, and response to, any incident. Shell would actively monitor the area and collect information about individuals entering the area. Shell also committed to performing an Emergency Response Plan (ERP) exercise prior to spudding the well. This exercise could increase the community's confidence in Shell, given some of the intervener's concerns over Shell's ability to respond in an emergency.[100]

With respect to location, the ERCB found that the drilling of the 68 Well as a vertical well "would increase the footprint of the project and would likely cause increased environmental impacts" but that it was the appropriate location "for reducing the project's overall footprint and enabling successful drilling and evaluation of the pool."[101] Shell did evaluate other

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95 *Ibid* at para 2.
96 *Ibid* at para 3.
97 *Ibid* at para 19.
98 *Ibid* at para 24.
99 *Ibid* at para 32.
100 *Ibid* at paras 37-40.
101 *Ibid* at para 44.

potential surface locations but the chosen site was the most economic and technically feasible.

With respect to environmental considerations the ERCB: (1) indicated that given that the 68 Well was exploratory, the scope of Shell's EA was commensurate with the project;[102] (2) noted that the proposed site for the Well was located on an existing access road and had a small area of disturbance. It provided the least possible impact to the area and would require no new access;[103] (3) noted that an incremental loss of rare plants was expected as a result of the development, and expected Shell to monitor the effectiveness of its rare plant transplant program, and to make that information publicly available. The ERCB also recognized the role that ASRD would play with respect to issues surrounding rare plants and Shell's related mitigation measures;[104] (4) noted that incremental loss of grizzly bear habitat was expected as a result of the project. However, Shell's mitigation efforts were "focused on reducing new access and … it was contributing to maintaining grizzly bear habitat on a regional basis by reclaiming older sites" in the Waterton area;[105] (5) disagreed with the interveners' expert's assertion that there may be a higher risk of ignited sour gas resulting in a sulphur dioxide release greater than an unignited sour gas release. The ERCB found that the risk to the public from exposure to the sulphur dioxide produced from ignited sour gas was "far less" than the risk due to potential exposure to unignited sour gas;[106] (6) appreciated the perspective of traditional users describing this area as a special area and a place for recreational use. However, Shell had obtained the necessary approvals through ASRD and the leaders of the interested groups did not object to the Waterton Applications or otherwise appear at the hearing; (7) accepted Shell's submissions that the 10-1 site "would have a small incremental surface disturbance relative to most of the other potential locations";[107] (8) pointed out that IL 93-09 "acknowledges that a definitive development plan is usually not possible at the outset and requires that an outline of the conceptual development be provided."[108] The ERCB was of the view that Shell had complied with the requirement that a development plan be prepared with a level of detail appropriate to the stage of development; and (9) accepted Shell's commitment "to carefully implement and monitor its traffic code of conduct" and "provide appropriate mitigation with regard to dust and noise."[109]

With respect to the pipeline applications, the ERCB: (1) accepted that production and fuel gas pipelines were needed to allow production from the 68 Well and to assist in the

102 *Ibid* at para 46.
103 *Ibid* at para 51. Company-wide, Shell implemented an access management policy which involves no net increase in public motorized access as a result of its projects. The Global Forest Watch report (submitted by the interveners), dealing with linear disturbances, access densities, and grizzly bear core security did not provide any information on intensity or timing of trail use or related specific ecological effects. Shell was also working on reducing its existing industrial footprint through the abandonment of wells. The quality and quantity of offsets that this well abandonment provided was something the ERCB was interested in understanding for future applications in the area.
104 *Ibid* at paras 56, 59.
105 *Ibid* at para 63.
106 *Ibid* at para 67. Shell also indicated that the volume of sour gas associated with flaring of sour vapours from the production test unit "would not exceed the limits set out in the small volume exemption in *Directive 060*." Accordingly, a temporary sour gas flaring approval was not required (*ibid* at para 65).
107 *Ibid* at para 72.
108 *Ibid* at para 78.
109 *Ibid* at para 86.

operations of a gas battery at the site.[110] It did not agree that the pipelines were needed to test the 68 Well; and (2) recommended that Shell redesign its public information package to better respond to residents' feedback and intervener concerns regarding the clarity of the ERP. Given the history of pipeline releases in the area, "the lack of effective continuous monitoring," and "the intermittent presence of Shell personnel" during production, additional measures should be developed to effectively respond to a potential incident.[111]

With respect to risk considerations, the ERCB: (1) acknowledged that risk assessments are not required, and (2) found that the failure rates used by Shell were inappropriate. Average failure rates across the whole province were not applicable to this system, and the failure rates applicable to this system "may indicate an increased risk to the public."[112]

With respect to pipeline operations:

(i) Shell was required to "improve its off-lease emission controls" and "review and revise its off-lease emissions plan for the area."[113] There was a general lack of confidence in Shell by residents in the area due to past incidents. The ERCB recommended that Shell report all odour complaints received to the ERCB, and that sour gas monitors be located at locations agreed upon by Shell and the ERCB, to provide a more objective odour monitoring system;[114]

(ii) The ERCB noted a lack of technical evidence regarding Shell's ability to detect corrosion events. However, the ERCB recognized the work Shell had done by testing new inspection tools and expected that "this or some other technology could provide evidence that would better demonstrate that the pipeline technology and pipeline integrity procedures are appropriate for this system";[115]

(iii) Shell lacked technical evidence indicating it had "the ability to detect or remove potentially corrosive materials that may accumulate in the annulus," and consequently, Shell needed a more rigorous monitoring method;[116]

(iv) Shell was to provide compatibility testing or field data to demonstrate that high-density polyethylene liners in the pipelines were suitable for this system. This was especially the case in light of a 2008 report that the Rilsan® liners had resulted in the Carbondale System failure. Given the lack of technical evidence, the ERCB expected "Shell to better demonstrate adherence to its management of change procedures";[117] and

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110 *Ibid* at para 98.
111 *Ibid* at paras 103-104.
112 *Ibid* at para 110.
113 *Ibid* at para 119.
114 *Ibid* at paras 119-20.
115 *Ibid* at para 129.
116 *Ibid* at para 131.
117 *Ibid* at para 133.

(v) Shell "had not adequately demonstrated that it had followed its own procedures" in its operation of existing infrastructure in the area.[118] Until Shell could "better demonstrate compliance with its own procedures," the ERCB found that it was not reasonable to tie in additional volumes and add more pipelines.[119] Shell could better demonstrate its willingness to properly operate infrastructure by:

- reducing the pipeline failure frequency,
- improving its ability to detect leaks and having fewer off-lease emissions,
- adhering to its traffic code of conduct,
- following through with its commitments, and
- conducting an independent review of its operations and sharing the results with the community.[120]

d. Decision

On 9 March 2011 the ERCB denied the applications for the gas battery, fuel gas, and production pipelines. The ERCB approved the Waterton Applications to drill the 68 Well (for exploration and not to produce) and for a fuel gas compressor, subject to conditions.

3. *TAYLOR PROCESSING INC: APPLICATIONS FOR THREE PIPELINE LICENCES AND A FACILITY LICENCE AMENDMENT — HARMATTAN-ELKTON FIELD*[121]

This decision is significant, since it is the first decision related to processing of natural gas directed from the NGTL system to remove NGLs. This decision sets out when such an application may be approved and the relevant factors to consider.

a. Application

Taylor Processing Inc (Taylor), a subsidiary of AltaGas Ltd, applied to amend its existing Harmattan-Elkton Gas Plant to co-stream 493.3 million cubic feet of natural gas per day off the NGTL system, and for a permit to construct and operate two natural gas pipelines and one high vapour pressure pipeline (the Taylor Project).[122]

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118 *Ibid* at para 136.
119 *Ibid*.
120 *Ibid* at para 137.
121 *Taylor Processing Inc.: Applications For Three Pipeline Licences and a Facility Licence Amendment — Harmattan–Elkton Field*, ERCB Decision 2010-036 (7 December 2010) [Decision 2010-036].
122 *Ibid* at paras 2-3. Co-streaming is defined as "[t]aking gas from the NGTL System upstream of an existing straddle plant, extracting NGL from the gas and injecting the dry residue gas downstream of the straddle plant" (*ibid* at 27).

b. Background

Taylor's application was the first submission regarding a co-streaming project since the release in 2009 of the *Inquiry into Natural Gas Liquids (NGL) Extraction Matters*.[123] The seven general factors[124] to be addressed in any future co-streaming or side-streaming application, set out in the *NGL Inquiry Report*, were considered in this decision.

c. Key Findings

In considering the applicable general factors, the ERCB held: (1) the findings of the natural gas supply reports are only one factor to be considered and there is no single factor that would present "a barrier to the approval of a project that may be in the overall public interest";[125] (2) the onus is on the applicant to show that an application is in the public interest. The ERCB did not accept the assessment of the industry participants as to how the ERCB should determine public interest in this case and confirmed that a project must not only benefit the applicant but also Albertans in general to meet the public interest test;[126] (3) despite arguments from industry participants that Taylor's application consisted of a new or green-field facility, the ERCB determined that Taylor's application was to amend an existing facility within existing lease boundaries and amendments to the gas plant were relatively minor;[127] (4) while a cost-benefit analysis (CBA) is not one of the seven factors found in the *NGL Inquiry Report*, in some circumstances a CBA may be relevant;[128] and (5) while the landowners had concerns regarding the pipeline route and the corresponding impact on their lands, the ERCB was satisfied that Alberta Environment (AENV) had been contacted for the appropriate approvals and that long-term effects on private lands were minimized.[129]

In considering the *NGL Inquiry Report* factors, the ERCB held that: (1) the factors set out in the *NGL Inquiry Report* do not exclusively determine the overall public interest, but were relevant in this case;[130] (2) even though the existing Cochrane Plant's[131] unused capacity "could be exacerbated by an approval" of the Taylor Project, the current Taylor Project would not "jeopardize the economic viability of the Cochrane Plant."[132] Further, the existence of unused capacity does not in and of itself affect the public interest such that Taylor's application should be denied;[133] (3) the Taylor Project would likely not have a detrimental effect on overall Alberta NGL production and may actually "present a significant upside for future incremental NGL recovery if current gas flows on the Western Leg continued at recent

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123 ERCB Decision 2009-009 (4 February 2009) [*NGL Inquiry Report*].
124 *Ibid* at 105-107.
125 Decision 2010-036, *supra* note 121 at para 25.
126 *Ibid* at paras 23, 25. Industry participants argued that Taylor failed to provide enough information to demonstrate the Taylor Project was in the public interest. In particular, there was a lack of evidence respecting sufficient gas supply for the Taylor Project. They submitted the gas supply forecasts were not tested in cross-examination and were not supported by testimony (*ibid* at para 22).
127 *Ibid* at para 33.
128 *Ibid* at para 43.
129 *Ibid* at para 48. Taylor also agreed to consult with affected landowners on construction schedules and hours of operation (*ibid*).
130 *Ibid* at para 53.
131 The Cochrane Liquid Extraction Plant is operated by Inter Pipeline Fund (the Cochrane Plant). Inter Pipeline Fund, "NGL Extraction," online: Inter Pipeline Fund <http://www.interpipelinefund.com/operations/ngl_extraction.php>.
132 *Ibid* at para 62.
133 *Ibid* at para 63.

rates."[134] In addition, the Taylor Project's "potential for increased NGL recovery from co-processing gas that would otherwise flow to the Cochrane Plant," and from processing bypassed gas during the Cochrane Plant outages, was significant to the overall public interest assessment;[135] (4) energy consumption would increase at the Harmattan Plant if the Taylor Project were approved. Even though energy costs can be considered by the ERCB in its assessment of the public interest in this instance, any inefficiency was insignificant and would "not negatively impact the petrochemical industry in Alberta or the public interest of Albertans";[136] (5) there was no evidence that the Cochrane Plant would not continue to be a viable straddle plant in the future;[137] (6) since the availability of capacity for processing raw gas is an important matter for the development and conservation of resources and is accordingly important to the public interest of Albertans, any approval will be conditioned to ensure that there is an ongoing preference to the processing of raw gas over NGTL gas;[138] (7) given that Taylor's application primarily amends an existing facility and does not result in any safety or environmental issues, duplication or proliferation concerns are not of great importance;[139] (8) the only way meaningful competition can occur is if more than one extraction facility exists on the same flow path.[140] The ERCB considers the matter of competition to be extremely important in terms of the public interest and without the proposed Taylor Project, there would be no meaningful competition on the western leg; and (12) the level of support demonstrated was sufficient enough to demonstrate the Taylor Project's viability.[141]

d. Decision

The ERCB approved the Taylor Project subject to certain conditions related to requirements that raw gas processing receive priority.

4. *TOTAL E&P CANADA LTD: APPLICATION TO CONSTRUCT AND OPERATE AN OIL SANDS UPGRADER IN STRATHCONA COUNTY*[142]

This decision sets out the relevant factors to consider in support of obtaining an oil sands bitumen upgrader approval.

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134 *Ibid* at para 78.
135 *Ibid* at para 80.
136 *Ibid* at para 86.
137 *Ibid* at para 98. In this regard, the ERCB noted that the impact on the Cochrane Plant would largely depend on the extent to which Taylor was able to negotiate extraction contracts with current shippers (*ibid* at para 97). Industry participants had concerns that this decision would set a precedent in respect of co-streaming. The ERCB recognized that the impacts of co- or side-streaming could become more serious in the future if more of these projects were proposed (*ibid* at para 99).
138 *Ibid* at para 108. Taylor is required to file annual reports with the ERCB regarding the value of raw gas processed. The ERCB would also require Taylor to demonstrate a financial incentive to process raw gas over NGTL gas (*ibid*).
139 *Ibid* at para 116.
140 *Ibid* at para 129.
141 *Ibid* at 141.
142 ERCB Decision 2010-030 (16 September 2010).

a. Application

TOTAL E&P Canada Ltd (TOTAL) filed applications, with both the ERCB and AENV pursuant to section 11 of the *Oil Sands Conservation Act*[143] for approval to construct, operate, and reclaim an oil sands bitumen upgrader (the Upgrader) in Strathcona County, near Edmonton (the TOTAL Project).

TOTAL's applications with AENV were to: (1) construct and operate a 47,200 cubic metre per stream day ("m^3/sd") upgrader and associated infrastructure;[144] and (2) authorize the diversion of up to 12,264,000 m^3 of water per year from the North Saskatchewan River, site water management plans for the construction and operation of the Upgrader, and the diversion of existing surface water runoff around the plant site.[145]

b. Background

The Upgrader is a 47,200 m^3/sd bitumen upgrader. The proposed TOTAL Project included water facilities and water pipelines and would be constructed in two phases. Phase One was scheduled to commence operation in 2014 with a capacity of 24,000 m^3/sd and Phase Two was scheduled to commence operation in 2018 with a cumulative capacity of 39,200 m^3/sd. The proposed TOTAL Project "would produce synthetic crude oil, petroleum coke, sulphur, diluents and other light hydrocarbon products.[146]

c. Key Findings

The ERCB determined that: (1) the TOTAL Project supported government policy to "promote value-added upgrading of energy resources";[147] (2) aside from the Alberta Industrial Heartland (AIH), TOTAL had examined two other possible locations, however, it "concluded that the AIH was the best location for the upgrader based on socioeconomic and environmental factors, transportation infrastructure, production and by-product utilization, potential integration opportunities and project economics";[148] (3) "predicted exposure concentrations were well below the toxicity limits for most chemicals" and the contributions of the Upgrader "would be small compared to existing concentrations in the area, which, with a few exceptions, were well below air quality standards and health benchmarks."[149] The Citizens for Responsible Development had proposed no practical alternative risk assessment process; and (4) with respect to health surveillance,[150] no correlation could be found between industrial pollution and the rates of hospital and emergency department admissions in the Fort Saskatchewan area.

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

144 Pursuant to the *Environmental Protection and Enhancement Act*, RSA 2000, c E-12 [*EPEA*].

145 Decision 2010-30, *supra* note 142 at 1. Pursuant to sections 37 and 50 of the *Water Act*, RSA 2000, c W-3.

146 Decision 2010-030, *ibid*.

147 *Ibid* at 7.

148 *Ibid* at 8.

149 *Ibid* at 26.

150 "Health surveillance involves the measurement of various health outcomes, including hospital admissions, mortality and incidence of various diseases and health conditions, including cancer." *Ibid* at 27.

With respect to water related matters: (1) TOTAL was required to "avoid the breeding and nesting periods of the pelicans when constructing its outfall" and to monitor the health of the colony in co-operation with ASRD.[151] It was noted that the concentration of phosphorus "is predicted to be above the [Canadian Council of Ministers of the Environment's] water quality guidelines downstream of the AIH" and that TOTAL was "engaged with AENV in developing a regional monitoring framework";[152] and (2) it is AENV's responsibility to allocate water resources and TOTAL would be subject to any restrictions imposed by AENV in that regard.

It was noted that AENV is also "the responsible authority for groundwater diversions and monitoring," and the ERCB expected TOTAL would "work with AENV to develop an appropriate groundwater monitoring program."[153] With respect to noise-related matters, the ERCB determined that TOTAL's NIA did not meet the requirements of the ERCB's *Directive 038: Noise Control*.[154] The two deficiencies were the omission of: (1) "significant sound sources, which includes the electrical substation and rail car movements associated with the shipment of various products from the Upgrader"; and (2) "information required to meet the minimum reporting requirements."[155] Accordingly, the ERCB conditioned its approval by requiring TOTAL to submit a revised NIA six months prior to construction and a follow-up "sound monitoring survey three months after start-up to verify compliance" with *Directive 038*.[156]

d. Decision

The ERCB found the TOTAL Project to be in the public interest and approved the applications, subject to the conditions that TOTAL would: (1) achieve a 99.5 percent sulphur recovery "on a calendar quarter-year basis within six months of commencing start-up activities";[157] (2) conduct a full-scale emergency response exercise "during a peak traffic period and include notification and actual or simulated evacuation of affected residents" prior to the start-up of operations;[158] (3) submit, for the ERCB's review, a site-specific ERP, containing an assessment of all hazards, including sour gas release, and appropriate responses; (4) submit a revised NIA, and redo its baseline sound monitoring surveys in accordance with *Directive 038*; (5) conduct a post-commissioning sound monitoring survey three months after start-up; and (6) satisfy the ERCB that construction has commenced by 1 October 2016, unless a later date is stipulated.[159]

Because the regulatory and policy frameworks for the AIH are constantly evolving, the ERCB found that it would be appropriate to stipulate a time limit on the approval. Accordingly, the approval expires on 31 December 2016, unless TOTAL satisfies the ERCB

151 *Ibid* at 35.
152 *Ibid* at 37.
153 *Ibid* at 41.
154 (16 February 2007) [*Directive 038*].
155 Decision 2010-030, *supra* note 142 at 44.
156 *Ibid* at 44-45.
157 *Ibid* at 16.
158 *Ibid* at 33.
159 *Ibid* at 47.

before 1 October 2016 "that construction has commenced or unless the Board stipulates a later date."[160]

5. *TOTAL E&P JOSLYN LTD: APPLICATION FOR AN OIL SANDS MINE AND BITUMEN PROCESSING FACILITY — JOSLYN NORTH MINE PROJECT FORT MCMURRAY AREA*[161]

This decision concerns the factors that the ERCB considers for the construction, operation, and reclamation of an oil sands surface mine and an ore preparation and bitumen extraction facility.

a. Application

TOTAL E&P Joslyn Ltd (TOTAL Joslyn) applied to the ERCB pursuant to section 10 and 11 of the *OSCA* and sections 3, 24, and 26 of the *Oil Sands Conservation Regulation*[162] and to AENV pursuant to the *EPEA* and the *Water Act* for the construction, operation, and reclamation of the Joslyn North Mine Project (the Joslyn Project). The Joslyn Project, located 70 km north of Fort McMurray, includes an oil sands surface mine and ore preparation and bitumen extraction facility. It is designed to produce 16,000 m^3/day of liquid hydrocarbon.[163]

b. Background

The Joslyn Project was reviewed by a Joint Review Panel (the Panel),[164] established in co-operation between the Canadian Environmental Assessment Agency (CEAA) and the ERCB. The Joslyn Project included the design, construction, and operation of a large variety of components including mining technology for the mine pit, froth treatment trains, systems to treat and recycle water, as well as a number of other components that would need to be built for the development to be fully functional.

c. Key Findings

With respect to the need for the Joslyn Project, alternatives considered and related matters, the Panel:

(i) Held that there was a need to replace conventional crude oil to meet Canadian and global energy market demands that the Joslyn Project would help to meet. The Joslyn Project represented an economic opportunity for Alberta and Canada;

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160 *Ibid*.
161 Decision 2011-005 (27 January 2011) [Decision 2011-005].
162 Alta Reg 76/1988 [*OSCR*].
163 Decision 2011-005, *supra* note 161 at 1.
164 The review was conducted in a manner that considered the ERCB's responsibilities under the *Energy and Utilities Board Act*, RSA 2000, c A-17 and the *ERCA*, as well as in accordance with the requirements set out in the *CEA Act*.

(ii) Stated that it expected oil sands developers would use extraction technology and, as a result, maximize resource recovery and reduce energy consumption, and that it believed TOTAL Joslyn's extraction process would meet this goal;[165]

(iii) Noted its concern about the increased rejection of asphaltene,[166] as it is a potentially reusable resource and excessive rejection of the substance can have negative environmental effects. TOTAL Joslyn's requested approval condition respecting the level of asphaltene rejection may not result in appropriate recovery of the resource and therefore the Panel did not believe that TOTAL Joslyn had justified using a less stringent standard;[167]

(iv) Expected further geotechnical drilling and analyses to be completed by TOTAL Joslyn for the critical mining structures to confirm the design assumptions within in the Application;[168]

(v) Noted that both TOTAL Joslyn and CNRL had been working together to maximize resource recovery along the common lease boundary to avoid leaving behind an oil sands pillar of unmined barrels of recoverable bitumen;[169] and

(vi) Found that a setback between the Ells River Valley and a clearing for the Joslyn Project was required to mitigate the significant effects of the Joslyn Project on wildlife. The Panel indicated, however, that ASRD was the most appropriate authority to determine the required setbacks and recommended that the ERCB and ASRD cooperate to assess the implications of resource sterilization in determining the most appropriate setback.[170]

With respect to environmental effects, the Panel:

(i) Concluded that the effects to species at risk within the local study area were significant because high-quality habitat would be directly affected and the habitat would be lost for decades. Further, there was uncertainty whether some wildlife would be able to repopulate the area since it is evident that most wildlife habitat

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165 Decision 2011-005, *supra* note 161 at 23. TOTAL Joslyn designed its extraction process to achieve the bitumen recovery target outlined in ERCB, *Interim Directive ID 2001-7: Operating Criteria: Resource Recovery Requirements for Oil Sands Mine and Processing Plant Sites* (9 October 2011).

166 "[H]igher quality deasphalted bitumen is a more marketable product than non-deasphalted bitumen." Decision 2011-005, *ibid* at 24.

167 *Ibid*.

168 "The ERCB is responsible for ensuring the geotechnical stability of overburdened disposal areas, reclamation stockpiles and mine pit wells." *Ibid*. "Canadian Natural Resources Ltd's (CNRL) written concern asked that TOTAL Joslyn identify mitigation measures so that the offstream storage pond, reclamation stock pile, and Joslyn Project camp would not negatively impact their operations" (*ibid* at 25). TOTAL Joslyn "noted it would use an observational approach, which uses monitoring data, to optimize the geotechnical design during construction" (*ibid*). The Panel recognized that the mining industry "widely uses" that approach. However, it expected TOTAL Joslyn "to approach the geotechnical designs conservatively, implement sufficient monitoring systems and have detailed contingency plans" (*ibid*).

169 *Ibid* at 26.

170 *Ibid* at 45.

within the local study area would be destroyed if the Joslyn Project was approved;[171]

(ii) Agreed with TOTAL Joslyn that there would be an adverse effect on vegetation with an open pit mine which could last for "decades until the vegetative communities could re-establish."[172] The Panel noted TOTAL Joslyn's commitment to progressive reclamation and limiting the Joslyn Project's footprint, and accepted TOTAL Joslyn's commitment to reclaim the landscape with the conditions and recommendations to which it had agreed.[173] Taking into account the implementation of the mitigation measures, the Joslyn project is not expected to "significantly and adversely affect wetlands or vegetation";[174]

(iii) Recognized TOTAL Joslyn's plans to manage water, concluding that the effects of the Joslyn Project on hydrology would be negligible;[175]

(iv) Concluded that the Joslyn Project was "unlikely to have significant adverse effects on fish and fish habitat," given that TOTAL Joslyn is required to put forth a plan to the Department of Fisheries and Oceans (DFO);[176]

(v) Concluded that in a regional context the air emissions released from the Joslyn Project were unlikely to pose an unacceptable environmental and public risk but agreed with EC that "24-hour air samples provide limited information on compliance" and recommended to the Government of Alberta (the Government) that it develop appropriate methods to implement continuing benzene monitoring. In addition, the Panel noted that air quality regimes and regulations are constantly evolving, and recommended and expected TOTAL Joslyn to stay abreast of these changes.[177]

(vi) Concluded that overall, with the implementation of TOTAL Joslyn's proposed mitigation measures and commitments, the Joslyn Project would not result in significant adverse effects to Aboriginal use of the lands for traditional purposes.[178]

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171 *Ibid* at 42. Interveners argued that the wildlife assessments by TOTAL Joslyn were in error and that there would be further loss of wildlife species than what TOTAL Joslyn had predicted in its assessment. Some parties were also concerned that TOTAL Joslyn had not developed an appropriate mitigation plan and that they had not used appropriate data.

172 *Ibid* at 51.

173 *Ibid*. The Panel noted the concerns of the interveners with respect to the transformation of the landscape from lowlands to uplands in the post-closure landscape but was of the opinion, however, that the Joslyn Project site could be reclaimed with a valued self sustaining ecosystem including wetlands.

174 *Ibid* at 52.

175 *Ibid* at 53.

176 *Ibid* at 66.

177 *Ibid* at 70-71. TOTAL Joslyn's mitigation plan related to air quality included: (1) "using technology for boilers and cogeneration units that would result in emitted oxides of lower nitrogen concentrations"; (2) "not continuously flaring during operations"; (3) "installing vapour recovery systems"; and (4) "minimizing potential odours" for the local community (*ibid* at 68).

178 *Ibid* at 76.TOTAL Joslyn's mitigation strategy included: (1) continued access west of the lease; (2) consultation with local trappers; and (3) prohibition of mine employees' access to natural areas outside the Joslyn Project for hunting, fishing, and other recreational purposes (*ibid* at 73).

With respect to cumulative effects, the Panel:

(i) Found that there was sufficient information from the hearing and TOTAL Joslyn's cumulative effects assessment to allow the Panel to make a determination about the significance of cumulative effects;[179] and

(ii) Encouraged TOTAL Joslyn to offset greenhouse gas emissions by implementing reduction measures elsewhere. Overall, however, the Panel was of the view that the Joslyn Project was "not likely to result in significant adverse environmental effects to air quality … provided that the mitigation measures … [were] completed and implemented."[180]

With respect to socio-economic effects, the Panel:

(i) Acknowledged the economic benefits associated with the development and found that the net benefits would be significant for the Regional Municipality of Wood Buffalo, Alberta, and Canada;[181]

(ii) Believed that a "fly in fly out" approach for 90 percent of the workforce represented the best alternative to limit an increase in population and the strain on public infrastructure and services, and concluded that as a result of TOTAL Joslyn's commitment to establish an onsite medical center, the effects of the Joslyn Project on health services would be appropriately mitigated;[182]

(iii) Supported "ongoing monitoring, assessment and management of health effects" in the region and expected TOTAL Joslyn "to honour its commitment to participate in regional health initiatives";[183] and

(iv) Found "that returning disturbed lands to a condition that is acceptable to [ASRD], AENV, and stakeholders, within established timeframes, [was] required for the public interest."[184] The Panel recommended that AENV establish "measurable targets" to encourage vegetative biodiversity in the reclaimed landscape and the post-closure landscape."[185]

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179 *Ibid* at 87. The Panel recommended that ASRD, in consultation with EC, work with TOTAL Joslyn before the Joslyn Project authorization to ensure the new mitigation plan reduces the overall cumulative effects on the wildlife" (*ibid* at 92).

180 *Ibid* at 105. The Joslyn Project would contribute 26.7 million tonnes of GHG emissions per year (0.0038 percent of global emissions, 0.17 percent of Canada's GHG emissions and 1 percent of Alberta's GHG emissions). TOTAL Joslyn was of the view that the Joslyn Project compared favourably to other similar projects in terms of [GHG] intensity" (*ibid* at 102-103).

181 *Ibid* at 109.

182 *Ibid*.

183 *Ibid* at 119.

184 *Ibid* at 128.

185 *Ibid* at 129.

The Panel recommended that before issuing any approvals to TOTAL Joslyn, AENV should require TOTAL Joslyn to

- provide functional plans to monitor end-pit lake water quality and assess treatment options …,
- provide functional plans to ensure that the volume of process-affected water and porewater in the end-pit lake does not exceed 15 million [m^3], and
- refine, update, and validate the models used for predicting water quality in the end pit lake.[186]

d. Decision

The Panel concluded that, assuming the Joslyn Project meets the conditions and recommendations,[187] it would

- meet the stringent new requirements for tailings management …,
- have no net significant adverse effect on species at risk,
- have no significant adverse effect on valued wildlife species, and
- have no significant adverse environmental effect on water quality.[188]

E. ALBERTA UTILITIES COMMISSION

1. *CAPITAL POWER MANAGEMENT INC AND CAPITAL POWER GENERATION SERVICES INC: AMENDMENT TO GENESEE 3 POWER PLANT APPROVAL NO U2010-32*[189]

This decision is interesting as it deals with the issue of when and if an approval condition can be amended once a subsequent regulation comes into effect which puts forward a less stringent requirement related to the condition's subject matter.

a. Application

Capital Power Management Inc and Capital Power Generation Services Inc (collectively Capital Power) applied to remove a condition from its 2001 490 megawatt (MW) power plant approval, which required Capital Power to offset approximately 52 percent of GHG emissions, such that emissions from its Genesee 3 coal-fired power plant (Genesee 3) are equivalent to those from a natural gas combined cycle power plant (the Offset Condition).

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186 *Ibid* at 137.
187 A total of 20 conditions were issued by the Panel. In addition, 17 recommendations were put forth by the Panel and 64 commitments were put forth by TOTAL Joslyn. All are attached to the decision, set out in Appendices 3-5. *Ibid* at 155-65.
188 *Ibid* at 2.
189 Alberta Utilities Commission (AUC) Decision 2011-026 (27 January 2011) [Decision 2011-026].

b. Background

The Offset Condition arose from a voluntary commitment made by Capital Power (then EPCOR) in support of approval for its Genesee 3 facility application in 2001.

In support of its application for removal of the Offset Condition, Capital Power relied on the provisions of the *Specified Gas Emitters Regulation*.[190] Under the *SGER* (enacted subsequent to the 2001 Genesee 3 approval), a large emitter is required to ultimately offset its GHG emissions down to 12 percent of its baseline established emissions.[191] Capital Power also argued that the Offset Condition was negatively impacting its competitiveness, being contrary to the "fair, efficient and openly competitive market" requirements under the *Electric Utilities Act*.[192]

c. Key Findings

The Alberta Utilities Commission (AUC) found that it would not be in the public interest to remove the Offset Condition nor to relieve Capital Power of the cost burden of adhering to the Offset Condition, "given that it was a voluntary commitment and given the environmental implications of doing so."[193]

In reaching this conclusion, the AUC made the following key findings:

(i) The Alberta Energy and Utilities Board (EUB), when granting the original approval, considered the environmental issues and concluded that the public interest would be served by including the Offset Condition as a condition of the approval. Given this fact, Capital Power had to satisfy the AUC that the Offset Condition was no longer in the public interest, contrary to the EUB's decision.[194]

(ii) The *SGER* did not oust the AUC's "statutory mandate respecting the public interest in relation to an application before it."[195] Although there are statutory environmental standards that apply to proposed power plants (or modifications to power plants), the AUC must consider "whether the impact on the environment is mitigated by such standards or whether additional conditions are required to address the potential impacts specific to that application."[196] The Offset Condition and the *SGER* "can both be applied if the [AUC] determines that it is in the public interest."[197]

(iii) The AUC agreed with the arguments of industry interveners that the impact of the Offset Condition was "on the profitability of [Genesee 3] rather than its

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190 AR 139/2007 [*SGER*].
191 *Ibid*, s 4.
192 SA 2003, c E-5.1 [*EUA*].
193 Decision 2011-026, *supra* note 189 at para 74.
194 *Ibid* at para 45. *EPCOR Generation Inc and EPCOR Power Development Corporation: 490 - MW Genesee Power Plant Expansion Application No 2001173*, EUB Decision 2001-111 (21 December 2001).
195 Decision 2011-026, *ibid* at para 47.
196 *Ibid* at para 48.
197 *Ibid* at para 50.

competiveness."[198] There were "no impacts on the functioning of the competitive market arising from the imposition of the [Offset Condition,] nor [were] there any material implications for the competitive position of [Genesee 3] in the market."[199] Not only does it fail to satisfy the public interest test merely to relieve one company from an economic disadvantage, if anything, the introduction of the *SGER* placed Genesee 3 in a "relatively better competitive position" because other competing coal power plants are now required to comply with the *SGER* requirements.[200]

(iv) The Offset Condition was a key provision of the original approval, because it mitigated the EUB's and intervener's concerns regarding the predicted increased GHG emissions from the proposed Genesee 3.[201] This commitment was made on a voluntary basis "with full knowledge of the costs involved, and in the face of regulatory uncertainty for the purposes of securing approval" for Genesee 3.[202]

d. Decision

The AUC denied the application of Capital Power to remove its Offset Condition from its 2001 490-MW power plant approval.

2. *ENMAX SHEPARD INC: CONSTRUCT AND OPERATE 800-MW SHEPARD ENERGY CENTRE*[203]

This decision sets out conditions that may be imposed related to an ERP and the extent to which the regulator takes into account property value impacts in the context of a facility approval. Of further significance is the AUC's consideration of the *EUA*'s section 95 requirement related to whether the manner in which ENMAX Shepard Inc's (ESI) interest in the Shepard Energy Centre (SEC) is held prevents any advantage due to the relationship between ESI and the City of Calgary.

a. Application

ESI filed an application (Shepard Application) with the AUC pursuant to section 11 of the *Hydro and Electric Energy Act*,[204] to construct and operate an 800-MW natural gas-fired combined-cycle power plant, known as the SEC.

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198 *Ibid* at para 67.
199 *Ibid* at para 74.
200 *Ibid* at para 64.
201 *Ibid* at para 73.
202 *Ibid* at para 70.
203 AUC Decision 2010-493 (21 October 2010) [Decision 2010-493].
204 RSA 2000, c H-16 [*HEEA*].

b. *EUA* Section 95 Issue

TransAlta Corporation (TransAlta), Maxim Power Corporation (Maxim), and Direct Energy Marketing Ltd (Direct Energy) intervened, expressing "concern regarding the relationship between ESI and the City of Calgary and question[ing] whether this relationship would give ESI an unfair advantage in Alberta's electricity market, thereby negatively affecting the fair, efficient and openly competitive electricity market in Alberta established by the [*EUA*]" (the "level playing field issues").[205]

The AUC denied standing to Direct Energy, Maxim, and TransAlta and found that it did not have the jurisdiction to consider the level playing field issues, as that consideration was reserved to the Minister of Energy by virtue of section 95 of the *EUA*. Section 95 of the *EUA* established "a complete and independent process for assessing whether ESI's interest in the SEC is held … in a manner that prevents any … advantage … as a result of its association with the City of Calgary."[206]

c. Key Findings

Of interest was that the AUC was "not prepared to unconditionally approve the [SEC] in the absence of a finalized hazard and risk assessment" and ERP; it directed ESI to complete these, with input from Shakers Family Fun Centre Inc (Shakers) and other interested stakeholders.[207] The AUC also directed ESI "to conduct at least one emergency response exercise involving Shakers and other interested stakeholders" before finalizing the ERP.[208] ESI must provide the finalized ERP to Shakers and the AUC, at which time the AUC will decide if further process to consider the ERP is necessary.[209]

In addition, the AUC accepted the "possibility that the construction and operation of the SEC may result in some value loss to Shakers," but it was persuaded that Shakers' business could successfully co-exist with the SEC.[210]

d. Decision

The AUC found that the approval of the SEC was in the public interest, however declined to issue an approval until ESI demonstrated compliance with section 95 of the *EUA* by filing with the AUC the Minister of Energy's authorization pursuant to section 95.

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205 Decision 2010-493, *supra* note 203 at para 6.
206 *Ibid* at para 70. Maxim obtained leave to appeal the AUC's standing decision to the Alberta Court of Appeal, however the AUC declined to adjourn the proceeding in the interim. See discussion of the appeal decision, *Maxim Power Corp v Alberta (Utilities Commission)*, 2010 ABCA 213, 482 AR 233 [*Maxim Power v AUC*] under the Standing section, Part VII, below.
207 Decision 2010-493, *ibid* at para 98.
208 *Ibid*.
209 *Ibid*.
210 *Ibid* at para 122.

F. CANADA-NEWFOUNDLAND AND LABRADOR OFFSHORE PETROLEUM BOARD

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) issued the following two decisions conditionally approving amendments to the Hibernia project's Benefits and Development Plans, as well as a pilot scheme at the White Rose Project. The amendments proposed to the Hibernia Benefits Plan are the first since the original Hibernia Benefits Plan was approved by the C-NLOPB in June 1986.

1. *HIBERNIA DEVELOPMENT PLAN AMENDMENT APPLICATION*[211]

a. Application

Hibernia Management and Development Company Ltd (Hibernia Management)[212] applied to the C-NLOPB, on behalf of its partners, for amendments to the Hibernia Benefits Plan, Southern Extension Project (January 2010), the Hibernia Development Plan Amendment Part I (January 2010), and the Hibernia Development Plan Amendment Part II (January 2010) (collectively, the Hibernia Amendments).

b. Background

The amendments sought by Hibernia Management to the Hibernia Benefits Plan were primarily related to the inclusion of the Hibernia Southern Extension project in the Hibernia Benefits Plan, research and development, and affirmative action, consistent with the C-NLOPB's Decision Report 2009.10.[213]

Proposed amendments to the Hibernia Development Plan related to the status of existing developments,[214] as well as Hibernia Management's plans for future developments, including the Hibernia Southern Extension Unit.

c. Key Findings

The C-NLOPB required confirmation by Hibernia Management "that the undertakings related to compliance with both the diversity, as well as the research and development and

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[211] C-NLOPB Decision Report 2010.02 (2 September 2010) [Decision 2010.02]. C-NLOPB decision reports are available online at <http://www.cnlopb.nl.ca/news/decisions.shtml>.

[212] Comprised of: ExxonMobil Canada (33.125 percent), Chevron Canada Resources (26.875 percent), Suncor Energy Inc (20 percent), Canada Hibernia Holding Corporation (8.5 percent), Murphy Oil Corporation (6.5 percent) and Statoil Canada Ltd (5 percent). Hibernia, "About Hibernia," online: Hibernia <http://www.hibernia.ca>.

[213] "The Hibernia Southern Extension … project includes the development of five fault blocks in the southern portion of the Hibernia field. Each block will be developed with an oil production well paired with a water injection well, the latter to provide pressure maintenance and recovery. The production wells will be drilled from existing facilities on the platform.… The estimated capital cost of the project is $1.735 billion." C-NLOPB, *Staff Analysis: Hibernia Benefits Plan Amendment, Hibernia Southern Extension Project* (2 September 2010) at 2.

[214] *Hibernia Development Plan Amendment Application*, C-NLOPB Decision Report 2009.10 (7 August 2009). Existing developments included the Hibernia A and B Pools, the Hibernia AA Block, and the Ben Nevis-Avalon Reservoir.

education and training aspects of the [C-NLOPB's] guidelines, apply to the entire Hibernia project including the southern extension."[215]

The C-NLOPB also conditioned the Hibernia Development Plan Amendment, Parts I and II, requiring Hibernia Management to submit an amended Environmental Effects Monitoring design that incorporates drilling and production activities associated with the new drill center and tie-back to the gravity based structure.

d. Decision

Accordingly, based on the conditions set out above, the C-NLOPB conditionally approved each of the proposed Hibernia Amendments.

2. *WHITE ROSE DEVELOPMENT PLAN AMENDMENT APPLICATION*[216]

a. Application

Husky Oil Operations Ltd (Husky) applied to the C-NLOPB to amend its White Rose Development Plan, West White Rose — Pilot Scheme (October 2009). The amendments to the Development Plan included the addition, over a two-year period, of two wells, an oil producer, and a water injector, to be drilled from an existing drill centre.

b. Background

The pilot scheme was to amend the existing White Rose Development Plan to allow Husky to obtain additional information on the West White Rose pool and better assess the feasibility of the full development of this pool.

c. Key Findings

In accordance with its Staff Analysis[217] of the proposed pilot scheme, the C-NLOPB found that certain conditions were necessary for the approval, including certain reporting requirements to the C-NLOPB regarding the results of the pilot scheme and no alteration to the pilot scheme as outlined in the application without C-NLOPB approval.[218]

d. Decision

Based on these conditions, the C-NLOPB conditionally approved the White Rose Development Plan Amendment, West White Rose — Pilot Scheme (October 2009).

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215 C-NLOPB, *Staff Analysis of the Hibernia Development Plan Amendment Application* (7 August 2009). See also Decision 2010.02, *supra* note 211 at 3.

216 C-NLOPB Decision Report 2010.01 (24 June 2010) [Decision 2010.01].

217 C-NLOPB, *Staff Analysis of the White Rose Development Plan Amendment Application* (24 June 2010).

218 Decision 2010.01, *supra* note 216 at 3.

II. TOLLS AND TARIFFS

A. ALBERTA COURT OF APPEAL

1. *CALGARY (CITY OF) V ALBERTA (UTILITIES COMMISSION)*[219]

This decision considers the used and useful requirement for the inclusion of a facility in rate base.

a. Application

The City of Calgary and the Utilities Consumer Advocate (UCA) sought leave to appeal the decision of the AUC establishing 1 April 2005 as the effective date for the removal of the natural gas storage facility (the Carbon Storage Facility) from the rate base of ATCO Gas and Pipelines Ltd (ATCO G&P).

b. Background

Previously, the AUC had established 10 October 2006 as the appropriate date for the removal of the Carbon Storage Facility from ATCO G&P's rate base. The AUC reconsidered and varied its decision following the Alberta Court of Appeal's ruling in the *Atco Gas and Pipelines Ltd v Alberta (Utilities Commission)*, or *Salt Caverns* decision.[220] As a result, 1 April 2005 was found to be the date when ATCO G&P had clearly indicated that the Carbon Storage Facility no longer had an operational purpose, was no longer used or required to be used in providing utility service, and should be withdrawn from rate base. In 2007 the EUB decided that the Carbon Storage Facility should remain in the rate base for revenue generation purposes even though it was not used or required to be used for operational purposes.[221] In *ATCO Gas and Pipelines Ltd v Alberta (Energy and Utilities Board),*[222] however, the Court held that, pursuant to section 37 of the *Gas Utilities Act*,[223] only assets that are "used or required to be used" in an operational sense may be included in rate base.

c. Key Findings

The proposed appeal did not raise a serious arguable question of law or jurisdiction. The AUC found as a matter of fact that as of 1 April 2005, the Carbon Storage Facility "was not being used to provide utility service."[224] This was not an error of law, but a correct application of the Alberta Court of Appeal's previous decisions indicating that the AUC "had no jurisdiction to include the Carbon storage facility in the rate base once the asset was no longer being used or required to be used in the operation of the regulated utility."[225]

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219 2010 ABCA 158, 487 AR 191 [*Calgary v AUC*].

220 2009 ABCA 246, 464 AR 275 [*Salt Caverns*]. This decision held that a change by the utility of the use of an asset and its withdrawal of the asset from its rate base does not constitute a "disposition" for the purposes of section 26(2)(d) of the *Gas Utilities Act*.

221 *ATCO Gas South: Carbon Facilities Part 1 Module — Jurisdiction (2005/2006 Carbon Storage Plan)*, EUB Decision 2007-005 (5 February 2007).

222 2008 ABCA 200, 433 AR 183, leave to appeal to SCC refused, 32761.

223 RSA 2000, c G-5 [*GUA*].

224 *Calgary v AUC*, *supra* note 219 at para 20.

225 *Ibid.*

In addition, it was not improper for the AUC to apply the date on which ATCO G&P decided that the Carbon Storage Facility was no longer used or required to be used in providing utility service:

> [T]he final determination as to whether a certain asset is to be used or is required to be used in providing utility service to the public falls within the jurisdiction of the Commission. Nonetheless, the utility company need not first obtain the Commission's consent or approval when deciding that an asset is no longer used or required to be used in providing service to the public. Although the Commission may require that the utility prove that the asset is no longer being used in its operations, and that the cessation of use of the asset is not imprudent, absent proof of imprudence, the adjustment date must be the date on which the utility, in fact, stopped using the asset, not the date on which the Commission agreed that the asset was no longer being used.[226]

d. Decision

Leave to appeal was denied.

B. NATIONAL ENERGY BOARD

1. *NOVA GAS TRANSMISSION LTD: RATE DESIGN METHODOLOGY AND INTEGRATION APPLICATION*[227]

This decision summarizes the three primary changes to the Alberta System's rate methodology and terms and conditions of service. In addition, this NEB decision relates to approval of the NGTL/ATCO G&P Asset Swap[228] being premature at the point this decision was rendered.

a. Application

NGTL applied to the NEB seeking two approvals. The first approval related to a settlement NGTL had reached with the Tolls, Tariff, Facilities and Procedures (TTFP) committee respecting the rate design methodology for its Alberta System (the TTFP Settlement), including approval of the transition mechanism for customers affected by rate changes determined by the TTFP Settlement. The second related to a commercial Integration Agreement[229] entered into with ATCO G&P, and approval, in principle, of Asset Swaps between NGTL and ATCO G&P to support this Integration Agreement.[230]

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226 *Ibid* at para 23.
227 *Reasons for Decision*, NEB Decision RHW-1-2010 (August 2010) [Decision RHW-1-2010].
228 See definition of "Asset Swap" in Part II.C.2.b.
229 The "Integration Agreement," executed in April 2009, "contemplates the commercial integration of NGTL's Alberta System with the AP system to form a single gas transmission business using a single tariff approved by the NEB." Decision RHW-1-2010, *supra* note 227 at 2.
230 *Ibid.*

b. Background

The TTFP Settlement caused

> three primary changes to the Alberta System's rate methodology and terms and conditions of service. First, the practice of equating the Firm Transportation Delivery rate (FT-D Rate) to the average Firm Transportation Receipt rate (FT-R Rate) [was] terminated. In its place, the Alberta System revenue requirement [is] divided into equal amounts for receipt and delivery services to determine rates. Second, a single primary delivery service [replaced the earlier] FT-D Service for delivery at Export Delivery Points and the Firm Transportation-Alberta Delivery Service (FT-A) for intra-Alberta deliveries. The proposed FT-D Service [is] available at three mutually exclusive delivery locations: FT-D1 (deliveries to major pipelines removing gas from the basin), FT-D2 (intra-basin or Intra deliveries excluding gas distribution utilities in Alberta (LDCs)), and FT-D3 (deliveries to LDCs and excluding FT-D1 and FT-D2). Third, the rate for Intra deliveries includes a transmission component in a demand form to account for the distance the gas is transported.[231]

c. Key Findings

In addition to granting approval, the NEB addressed the following matters: (1) it is the NEB's practice to treat negotiated settlements as a package and therefore it did not impose a time limit or geographical boundary to the TTFP Settlement;[232] (2) the NEB was "not in a position to include the Ventures pipeline, a pipeline not under its jurisdiction, in the Integration Agreement";[233] (3) regarding NGL ownership issues on the Alberta System raised by BP Canada Energy Co (BP), the NEB noted that BP is not a Straddle Plant delivery contract holder with ATCO G&P and the NEB "has no jurisdiction over commercial arrangements between extraction plants and third parties such as BP";[234] (4) consultation with landowners on the Asset Swap requires consultations regarding the implications of the difference between federal and provincial regulation that would affect landowners; (5) the NEB directed NGTL to include "estimates of the cost of abandonment for assets coming into and those leaving the NEB jurisdiction in the section 74 filings supporting the asset swaps," and considerations related to liabilities for future abandonment costs and NGTL consultation with landowners;[235] and (6) approval of the Integration Agreement was conditioned to its commercial implications being "incorporated in NGTL's rate design methodology and services."[236]

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231 *Ibid* at 3. "The current intra-Alberta delivery rate includes only a metering component and has a commodity rate form" (*ibid*).

232 *Ibid* at 6. However, in the future, the NEB will require sufficient information to assess the continued appropriateness of certain ceiling and floor rates from the average Firm Transportation Receipt (FT-R) rate "filed in a two phased study (*ibid*). Two of the interested parties indicated that "subsequent extensions to the Alberta System may require a review of the rate design methodology since rate design is expected to change over time with the evolution of any pipeline system" (*ibid* at 5).

233 *Ibid* at 7.

234 *Ibid* at 8.

235 *Ibid* at 11-12.

236 *Ibid* at 12.

d. Decision

The NEB approved NGTL's application, which applied-for rate design was supported by an unopposed resolution of the TTFP.[237] Approval of the Asset Swap "in principle" was premature, since it would still be the subject of future detailed section 74 applications to be filed with the NEB.[238]

C. ALBERTA UTILITIES COMMISSION

1. *ATCO GAS: 2008–2009 GENERAL RATE APPLICATION — PHASE II NEGOTIATED SETTLEMENT*[239]

This decision summarizes the AUC's decision related to ATCO Gas' General Rate Application — Phase II. Of interest in this decision is the AUC's review of the factors to consider related to use of deferral accounts.

a. Application

ATCO Gas filed a 2008-2009 General Rate Application — Phase II with the AUC. The Phase II Application relates to its north and south service territories.

b. Background

In the previous ATCO Gas Phase II proceeding,[240] the EUB conducted a comprehensive rate design review to establish rates for 2007. Significant changes to ATCO Gas's rate design were made and several issues were directed to be addressed in the next GRA Phase II.[241]

For this application, ATCO Gas requested approval for: (1) the Cost of Service Study (COSS) methodology used for ATCO Gas North COSS and ATCO Gas South COSS; (2) the proposed Rate Groups; (3) the Terms and Conditions of Service (T&Cs) for Distribution Access Service and Distribution Service Connections; (4) the use of Deferral Accounts to address outstanding matters related to placeholders and to address the removal of the Carbon Storage Facility from utility service; and (5) final rates in 2008 and 2009.[242]

The AUC "advised the Settlement Parties that … it was not prepared to accept the Settlement on the basis of a single 2008-2015 arrangement because approval was not obtained in Decision 2009-150[243] for negotiation of a settlement for the 2010 to 2015 period. The [AUC] proposed splitting the Settlement timeframe into two separate applications."[244]

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237 No party expressed opposition to the application. *Ibid* at 2.
238 *Ibid* a 9.
239 AUC Decision 2010-291 (25 June 2010) [Decision 2010-291].
240 *ATCO Gas: 2003-2004 General Rate Application Phase II Cost of Service Study Methodology and Rate Design and 2005-2007 General Rate Application Phase II,* EUB Decision 2007-026 (26 April 2007).
241 Decision 2010-291, *supra* note 239 at para 7.
242 *Ibid* at para 9.
243 *ATCO Gas: Request to Negotiate and ENMAX Rate Class Issue 2008-2009 General Rate Application — Phase II,* AUC Decision 2009-150 (25 September 2009).
244 Decision 2010-291, *supra* note 239 at para 24 [footnote added].

The settlement parties were unanimous in their opposition to this and the AUC accepted "the 2008-2015 timeframe … as a single indivisible application."[245]

The AUC examined its authority to fix just and reasonable rates and tolls and to approve a settlement. Under the *GUA* and *Rule 018*,[246] "in assessing whether or not to approve the Settlement, the [AUC] must accept or reject the Settlement in its entirety, and in so doing must consider the fairness and public interest factors."[247]

c. Key Findings

The AUC made the following findings:

(i) The AUC was "satisfied that the information filed with the Settlement, the notice provided by ATCO Gas and supplemented by the AUC, and the attendance of [AUC] staff in the negotiations provid[ed] a level of assurance that interested parties were provided with sufficient notice, adequate materials, and the opportunity to meaningfully participate, and that the negotiations were conducted in an open and fair manner."[248]

(ii) The AUC agreed with ATCO Gas's submissions that the settlement was in the public interest, including that it would result in rates that are just and reasonable. ATCO Gas submitted that: (1) the Settlement signatories were knowledgeable and their consensus was "a basis on which the [AUC] could reasonably conclude the Settlement was in the public interest"; (2) the Settlement resulted "in greater regulatory efficiency compared to a litigated process"; (3) "the rates resulting from the Settlement [were] just and reasonable and rate shock [was] not occurring for any rate group"; and (4) "the Settlement is consistent with existing law and [AUC] policies."[249]

(iii) The AUC accepted the timeframe as "a single indivisible application," even though permission had not been obtained from the AUC for the extended time frame.[250]

(iv) The creation of the Mid Use Rate Group was "a reasonable attempt to deal with the issues of homogeneity … the introduction of the Mid Use Rate Group [would] result in rates that are just and reasonable."[251]

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245 *Ibid* at para 25-26.
246 AUC, *Rule 018: Rules on Negotiated Settlements* (Calgary: AUC, 2008) [*Rule 018*].
247 Decision 2010-291, *supra* note 239 at para 43.
248 *Ibid* at para 66. The AUC had three concerns regarding this objective. First, lack of notice to all interested parties that might be impacted by the settlement. Second, the time frame and scope covered by the settlement. Third, representation of the Mid Use and Irrigation Rate Groups. The AUC's first concern was addressed by the issuance of the additional notice with respect to the settlement application. AUC concerns regarding representation were addressed by Public Institutional Consumers of Alberta's active participation in the hearing.
249 *Ibid* at para 74.
250 *Ibid* at paras 89-90.
251 *Ibid* at para 105.

(v) Change in COSS classification and distribution methodologies previously established was accepted.

The proposed changes to the T&C was accepted. The AUC will monitor impacts of these changes, particularly those related to the Low and Mid Use Rate Group.[252]

In addition, the AUC reviewed the use of deferral accounts factors, including:

- materiality of the forecast amount;
- uncertainty regarding the accuracy and ability to forecast the amount;
- whether or not the factors affecting the forecast are beyond the utility's control; and
- whether or not the utility is typically at risk with respect to the forecast amount.[253]

Additionally, deferral accounts should satisfy the "symmetry factor" by: (1) providing a degree of protection to both the utility and the customers, from circumstances beyond their control with symmetry existing between costs and benefits for both; and (2) consistently applying "individual mechanisms involved in the use of each deferral account" between both test and non-test years.[254] The uncertainty and risk for both ATCO Gas and ratepayers evaluated in light of the four factors, in addition to the requisite symmetry factor, lead the AUC to accept the use of the deferral accounts.

With respect to rates, the AUC considered whether there could be rate shock due to changes to rate design or COSS cost allocations, and found that the results of the proposed rate designs, which showed revenue-to-cost ratios for all rate groups close to 100 percent, were "just and reasonable and not indicative of rate shock."[255] The AUC therefore approved the splitting of the Low Use Rate Group, the Mid Use Rate Group designation, as well as the COSS methodological changes that the settlement required and that was reflected in the 2009 COSS.

Finally, the AUC did "not find any of the re-openers to be unusual or inappropriate but caution[ed] that an approval by the [AUC] of the Settlement [did] not include approval of an agreement of the parties to extend the term as contemplated in clause 1.2" of the Settlement (clause 1.2 included a provision for an extension beyond the year 2015).[256]

d. Decision

The settlement was approved as filed, in its entirety.

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252 *Ibid* at para 135.
253 *Ibid* at para 144.
254 *Ibid* at para 145.
255 *Ibid* at para 166.
256 *Ibid* at paras 167-68.

2. *ATCO PIPELINES: 2010-2012 REVENUE REQUIREMENT SETTLEMENT AND ALBERTA SYSTEM INTEGRATION*[257]

This decision relates to the integration of the ATCO Pipelines (AP) and NGTL systems and the related revenue requirement settlement discussions with customers.

a. Application

AP filed an application with the AUC (the Integration Application) seeking a number of approvals from the AUC dealing with a proposal to integrate AP and NGTL systems for regulated gas transmission services in Alberta. Upon filing the Integration Application, AP began engaging with customers in revenue requirement settlement discussions, and subsequently applied for approval of a 2010-2012 Revenue Requirement Settlement (AP Settlement Agreement).

b. Background

"[T]o streamline the provision of natural gas transmission services and address competitive pipeline issues in Alberta," AP and NGTL entered into the Integration Agreement.[258]

> The Integration Agreement requires AP and NGTL, subject to acceptable regulatory approvals, to swap ownership of certain physical assets within distinct operating territories or "footprints" in Alberta (Asset Swap), and to work together in Alberta under a single rates and services structure, while maintaining separate ownership, management and operation of their assets (Integration).… AP proposed that NGTL would include AP's approved revenue requirement, through a monthly charge by AP to NGTL (AP Charge), in NGTL's revenue requirement which will be collected from customers using the Alberta System.[259]

The total Alberta System revenue requirement would consist of "the AP revenue requirement approved by the [AUC] and charged to NGTL plus the NGTL revenue requirement approved by the [NEB]. This would form the basis for the determination of Alberta System rates and tariffs for all customers."[260]

c. Key Findings

With respect to the settlement, taking guidance from *ATCO Electric Ltd v Alberta (Energy and Utilities Board)*,[261] the AUC held that in approving or denying the settlement it must consider fairness and the public interest.

With respect to the fairness of the Negotiated Settlement Process, the AUC considered the fact that notice requirements to participants were met. The AUC observer also "supported

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257 AUC Decision 2010-228 (27 May 2010) [Decision 2010-228].
258 *Ibid* at para 115. See also the discussion of the Integration Agreement in the NEB decision regarding NGTL's Rate Design Methodology and Integration Application in Part II.B.1, above.
259 *Ibid* at para 2.
260 *Ibid*.
261 2004 ABCA 215, 361 AR 1.

AP's assertion that the Settlement process was open and fair and provided a forum for meaningful stakeholder participation."[262] The parties to the settlement had a substantial amount of information at the time the negotiation commenced. Because all participants approved the AP Settlement Agreement, the requirements of *Rule 018* were also met.[263]

On the question of whether the rates would be just and reasonable and in the public interest, the AUC conducted an in-depth analysis of revenue requirement comparisons and concluded the 2010 negotiated revenue requirement would not "result in unjust or unreasonable rates or be patently contrary to the public interest or contrary to the law."[264]

In reviewing the individual components of the AP Settlement Agreement, including: (1) Rate Base – 2008 Closing Balance/2009 Opening Balance; (2) cost of capital; (3) operating and maintenance expenses; (4) audit provisions; (5) capital expenditures; (6) line pack; (7) annual interim and final revenue requirement process; and (8) issues addressed in other proceedings, the AUC concluded that the negotiated settlement process was fair and approved the AP Settlement Agreement as filed.

With respect to Integration, the AUC finds authority in section 22 of the *GUA* to consider the application for Integration. The AUC noted that the benefits of Integration include: (1) elimination of stacked tolls for customers who transport gas in Alberta on both the AP and NGTL pipeline systems; (2) elimination of duplicative terms of service; (3) reduction of "the regulatory burden and costs which result when NGTL and AP compete for customers in Alberta, often leading to protracted and contentious regulatory proceedings"; (4) enhancement of the "orderly, efficient, and cost effective expansion" of the Alberta System via increased coordination in system planning; and (5) more efficient facility applications through the use of the exclusive footprint areas.[265]

With respect to contract transitioning,[266] approval was granted in principle. AP was directed to file an application that addressed transitioning concerns. The Asset Swap was approved in principle. NGTL and AP were required to "finalize footprint boundaries and identify specific facilities to be swapped."[267]

With respect to line pack, the AUC agreed "in principle that the ownership of the line pack should be with AP if the Integration is approved, at least for the assets to be swapped."[268] The AUC directed AP "to file an application respecting the Asset Swap, to include line pack considerations, within a reasonable period of time following this Decision and with a view to allowing sufficient process time for consideration by all parties."[269]

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262 Decision 2010-228, *supra* note 257 at para 53.
263 See *Rule 018*, *supra* note 246.
264 *Ibid* at para 73.
265 *Ibid* at para 131.
266 As part of the implementation of the Integration, all AP contracts would be transitioned to Alberta System contracts with NGTL (Contract Transition).
267 Decision 2010-228, *supra* note 257 at para 14.
268 *Ibid* at para 175.
269 *Ibid* at para 177.

d. Decision

The AUC approved the AP Settlement Agreement, as well as the proposed Integration of the regulated gas transmission service in Alberta of AP and NGTL under a single rate and services structure, while maintaining separate ownership, management, and operation of their respective assets. The AUC also approved the Integration matters relating to Contract Transitioning and the Asset Swap in principle, subject to the requirements for further approval and all other directions and terms set forth in the decision.

3. *ATCO PIPELINES: CONTRACT TRANSITION*[270]

In this decision the AUC considers AP's Contract Transition application, addressing the matters that were not addressed in sufficient detail when AP's Contract Transition and Asset Swap with NGTL were approved in principle.[271] Interestingly, the AUC found that concerns raised were primarily resolved because the parties remained effectively in similar commercial positions after the proposed Contract Transitioning as before.

a. Application

In its application, AP proposed to address issues such as gas quality specifications, transition of AP's straddle plant delivery (SPD) contracts to NGTL contracts, and AP's purchase of line pack from its customers. AP specifically requested approval of

1. the Contract Transition in its entirety, and

2. AP's purchase of line pack.[272]

b. Background

The AUC received submissions from numerous industry members, including AltaGas Ltd (AltaGas) and BP.

In Decision 2010-228, the AUC found that the Integration between AP and NGTL would generally benefit customers requiring the use of both pipeline systems by providing efficiencies and eliminating stacked tolls. With respect to Contract Transition and Asset Swap, however, the AUC directed AP to file a further application, the subject of this decision, to address: (1) the "terms and conditions of service as it relates to gas quality issues"; (2) "a comprehensive draft or final agreement between NGTL and ATCO Gas"; and (3) "how AP's non-standard agreements and SPD contract holders would be transitioned to NGTL contracts."[273]

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[270] AUC Decision 2011-160 (20 April 2011) [Decision 2011-160].
[271] See AUC Decision 2010-288, *supra* note 257, discussed in Part II.C.2, above. See also discussion of NEB's related decision in Part II.B.1, above.
[272] Decision 2011-160, *supra* note 270 at para 6.
[273] *Ibid* at para 14.

In Decision 2010-228, the AUC provided an overview of the Contract Transition component of the Integration and indicated that AP was developing transition mechanisms with its customers to ensure that rights and obligations were carried forward. SPD contracts were to be "converted to the extent possible (with consideration for existing AP commitments) to an appropriate NGTL Contract."[274] "With the exception of SPD customers, no customers have objected to either AP's proposed Integration or to the Contract Transition."[275]

c. Key Findings

The AUC considered the following issues in its evaluation of AP's application: (1) transition of SPD contracts; (2) line pack; and (3) other integration issues, including the gas quality, ATCO Gas contract, and non-standard contracts.

With respect to the transition of SPD contracts, AP requested approval of the transitioning of these contracts to NGTL Other Services Straddle Plant Delivery Agreements (OS SPD Agreements), and submitted that it has worked with NGTL to develop agreements that would keep the SPD customers "whole."[276] Intervener concerns included title to the NGLs, continuation of cost-based rates, timing of the transition, the jurisdiction to terminate SPD contracts, and the terms of the OS SPD Agreement.

The AUC found that: (1) it has the jurisdiction to amend or terminate the SPD contracts if it finds doing so to be in the public interest; (2) the OS SPD Agreements, in combination with an exception to the extraction convention on the NGTL system,[277] "will put the straddle plants functionally in the same position" as they are under current contract "with respect to their ability to extract NGL and to receive the value of the extracted NGL";[278] (3) overall, the proposed terms of the OS SDP Agreement, in conjunction with commitments made by NGTL, provide sufficiently analogous commercial provisions for the straddle plant owners to those under current agreements with AP. The AUC also noted that "no party, other than AltaGas and BP, objected to the transition plan."[279]

With respect to the line pack, the AUC stated in Decision 2010-228 that ownership of the line pack should be with AP for Integration, given that assets would be swapped with NGTL,

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274 *Ibid* at para 17.

275 *Ibid* at para 18.

276 *Ibid* at para 24. What the OS SPD Agreement "does not do, as it is not within NGTL's tariff, is provide shippers with title to extracted gas as had been the case" under previous customer agreements with AP (*ibid*). AP argued, however, that SPD customers such as AltaGas would remain similarly situated "in terms of control over, and ability to capture value of," its extracted NGTL (*ibid*). Interveners requested that any contract transition "preserve the essential commercial terms of the existing arrangement," including ownership of NGL, in order to avoid the risk that removal of ownership rights would prejudice their ability to extract NGLs in the same manner and at the same cost as under existing contracts, as well as the risk of rival elements to the NGL if title were lost (*ibid*).

277 Under the current extraction convention on the NGTL system, "the right to extract NGL from natural gas transported on the NGTL system is held by shippers placing gas nominations" under NGTL delivery service contracts downstream of a straddle plant. *Ibid* at para 31, citing *NGL Inquiry Report*, *supra* note 123 at 12. Parties removing or extracting components upstream of the delivery point "would, by convention, negotiate with the delivery shippers for the right to have gas directed to their straddle plant for the purposes of extraction" (*ibid*).

278 *Ibid* at para 99.

279 *Ibid* at para 101.

which owns its line pack. AP stated that its line pack would be "included in its rate base, with the resulting revenue requirement being passed on to NGTL to be collected from all Alberta System customers."[280] AP proposed that it purchase the line pack on the total AP system to avoid uncertainty and increased administration associated with owning only a portion of the line pack.[281] Accepting that customers are the current owners of the line pack on the AP system, and noting that no interveners raised concerns regarding AP's proposal to purchase all line pack in its system prior to Integration, the AUC further found that AP's proposed line pack calculation and volume/pricing approach was supported by the evidence.

Gas quality was an issue because AP and NGTL have differing requirements for gas quality specification, the most significant being AP's more stringent requirement for a lower sulphur content. Neither AP's nor NGTL's tariffs, however, have a delivery gas specification, and "[c]urrently 30-40 percent of AP's receipts are from the NGTL system," a large portion of which are delivered to local distributing companies.[282] The AUC found that AP, NGTL, and local distributing companies were sufficiently able to address these issues as needed.

With respect to non-standard contracts currently held with AP, the Consumers' Coalition of Alberta submitted that all customers receiving discounted rates due to competition between AP and NGTL should pay standard rates. AP agued an ongoing business case for grandfathering Dow Chemical Canada ULC's competitive mechanism. This issue is within the NEB's jurisdiction.[283]

d. Decision

The AUC found that the benefits associated with Integration are furthered by AP's Contract Transition and that contract transitioning from AP to NGTL is in the public interest. Accordingly, the AUC approved the transitioning of AP contracts to NGTL system contracts, effective on the Integration Effective Date, in accordance with AP's application. "The filing and approval of an Asset Swap application … [will] not be a precondition to implementation of Integration."[284] The AUC also approved AP's proposal for the purchase of the line pack.

Subsequent to the AUC issuing this decision, BP filed an application with: (1) the AUC for review of Decision 2011-160; (2) the NEB for review and variance of Decision RHW-1-2010;[285] and (3) the Alberta Court of Appeal for leave to appeal Decision 2011-160. AltaGas is also seeking leave to appeal Decision 2011-160.[286] Generally, BP asked for suspension of

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280 *Ibid* at para 116.

281 No parties opposed AP's purchase of line pack per se, but Gas Alberta Inc and the UCA raised concerns regarding "AP's method for determining the volume and price to be refunded to customers form AP's purchase of line pack" (*ibid* at para 117).

282 *Ibid* at para 135.

283 *Ibid* at paras 145-47.

284 *Ibid* at para 151.

285 *Supra* note 227.

286 BP's application for review and variance of Decision 2011-060, *supra* note 270, was denied in AUC Decision 2011-389, *BP Canada Energy Company: Decision on Preliminary Question — Review and Variance of Alberta Utilities Commission Decision 2011-160, ATCO Pipelines Contract Transition* (27 September 2011). BP's application for review and variance of Decision RHW-1-2010, *ibid*, was denied in NEB Order TG-05-2011, *NOVA Gas Transmission Ltd (NGTL) Application for Final 2011 Tolls for the Alberta System and Implementation of Alberta System Integration dated 16 May 2011; and Application of BP Canada Energy Ltd (BP) for Review and Variance of Board Decision RHW-1-2010*

the AUC and NEB decisions, as they related to AP SPD arrangements, and to allow parties to explore options that would permit the benefits of Integration to proceed while preserving straddle plant owners' title to NGLs (or to impose conditions protecting SPD customer rights).

4. *ATCO UTILITIES: CORPORATE COST ALLOCATION METHODOLOGY*[287]

This decision relates to the allocation of corporate costs and the factors that were considered in this regard.

a. Application

ATCO Gas, ATCO Pipelines, and ATCO Electric Ltd (ATCO Electric) filed an application before the AUC, seeking approval of the current methodology (Methodology) and model (Model) used by Canadian Utilities Ltd and CU Inc (ATCO Corporate Office) "for allocation of common costs (Corporate Office Costs) for governance, financial and administrative services that cannot be more directly assigned on a cost efficient basis" (Cost Allocation Application).[288]

b. Background

The Methodology for the allocation of Corporate Office Costs consists of the ATCO Corporate Office utilizing a cost allocation model and a three-factor composite financial formula for attributing a portion of its corporate services to ATCO.[289] The three factors are: (1) Direct Cost Assignment; (2) Allocation Based on Causation; and (3) Allocation Based on Formula. In argument, ATCO Electric confirmed the Methodology by stating that "recourse to the 'allocation formula' only occurs once it has been determined that the subject cost(s) cannot be directly assigned and cannot be logically assigned using a specific cost causation driver."[290]

The EUB required ATCO Electric to continually verify and track the Corporate Office Costs, and conduct periodic reviews of allocation methodologies and cost drivers. This requirement for periodic review of allocation methodologies and cost drivers was again addressed in Decision 2008-100.[291] ATCO Electric retained KPMG LLP (KPMG) "to conduct an independent third party review of the Methodology and drivers used in the Model in order to determine if the Model was still valid" and to prepare a report based on the results.[292] The Utilities Consumer Advocate (UCA) filed a motion alleging that the KPMG

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and Order TG-04-2010 dated 6 June 2011 (19 August 2011). BP's leave to appeal applications are proceeding under Action Numbers A11010128AC and A11010129AC, and were adjourned to 6 December 2011 as of 19 October 2011.

287 AUC Decision 2010-447 (20 September 2010) [Decision 2010-447].

288 *Ibid* at para 1.

289 *Ibid* at para 8.

290 *Ibid* at para 9.

291 *Atco Electric: Stand Alone Study*, AUC Decision 2008-100 (21 October 2008).

292 *Ibid* at para 16.

report[293] was insufficient to comply with the earlier direction of the AUC.[294] The AUC denied the UCA's motion but concluded that the "persuasiveness of the evidence" put forward would be determined in a later proceeding after consideration of the entire record.[295]

The validity of the KPMG Report and the allocation Methodology used by ATCO Electric with respect to corporate costs were the central issues in the Cost Allocation Application.

c. Key Findings

The AUC found an overall level of compliance noting that ATCO Electric had: (1) engaged a third party expert to conduct an independent review of the Model; (2) developed a set of criteria to assess the formula employed in the Model; (3) "reviewed the ATCO corporate structure"; (4) "reviewed documentation related to the Corporate Office Costs"; (5) "conducted research to confirm that shared service type structures are common in the utility industry and that the type of costs (fiduciary in nature) are such that they are appropriately allocated based on a financial composite type of formula"; and (6) "concluded the three-factor composite formula used in the Model '[was] representative of the underlying reasons for the existence of these costs.'"[296]

The AUC expressed concerns regarding the completeness of the KPMG Report and agreed with the UCA that it was "a high level comparison of the allocations used by ATCO to a select set of comparators, without any detailed analysis of the impact of the cost drivers impacting ATCO."[297] Additionally, neither ATCO nor KPMG "provided a detailed explanation of why the three-factor financial composite formula used in the Model is superior to the other formulae reviewed."[298] The AUC was not persuaded, however, to require additional reports or alter the current Methodology.

d. Decision

The AUC accepted the Cost Allocation Application and the KPMG Report as support for continued use of the current Methodology and Model, subject to more detailed review and analysis in the next periodic review.

5. *REGIONAL WATER SERVICES LTD: 2007-2010 GENERAL RATE APPLICATION*[299]

This decision is an interesting evaluation of a general rate application for a water utility. It addresses in detail issues related to contributions in aid of construction (CIAC) and use of

293 KPMG, *ATCO Utilities (ATCO Electric, ATCO Gas, ATCO Pipelines) Corporate Service Cost Allocation Model Review* (September 2009), online: AUC <http://www.auc.ab.ca/eub/dds/eps_Query/TransferAttachmentWS.aspx?DOCNUM=128607&SIZE=525511>.
294 Decision 2010-447 *supra* note 287at para 17.
295 *Ibid* at para 19.
296 *Ibid* at para 46.
297 *Ibid* at para 48.
298 *Ibid* at para 52.
299 AUC Decision 2011-061 (18 February 2011) [Decision 2011-061].

a revenue deficiency deferral account (RDDA). Interestingly, only approximately 25 percent of the proposed rate base amount was approved.

a. Application

Regional Water Services Ltd (RWSL), filed a General Rate Application (GRA) with the EUB that requested approval of a final tariff for the test periods 1 July 2007 to 31 December 2007 and 1 January 2008 to 31 December 2008 (the 2007-2008 GRA).[300] On 26 February 2010, RWSL filed a revised application and revised terms and conditions which extended the test periods to include 1 January 2009 to 31 December 2009 and 1 January 2010 to 31 December 2010 (the 2007-2010 GRA).[301]

b. Background

RWSL owns and operates a water system that provides public utility services to Monterra on Cochrane Lakes, a residential development. The EUB had previously set rates for RWSL on an interim, refundable basis, effective 1 December 2007.[302]

The Monterra Group and the Monterra Home Owners Association (Monterra), and landowners and residents serviced by RWSL, intervened in the proceeding to set RWSL's final rates for the 2007 to 2010 period.

c. Key Findings

With respect to the CIAC, the AUC determined that RWSL imprudently failed to obtain a sufficient contribution from the affiliated developer, and as such its rate base must be reduced by the amount of a deemed CIAC. The AUC deemed a CIAC from the developer of $15 million.[303] The AUC's ruling as to CIAC was based on its findings that: (1) RWSL did not demonstrate that its proposed revenue requirement can be recovered from prospective rate payers within a reasonable time frame under rates that would be acceptable to lot owners in the Monterra development;[304] (2) "by failing to require a contribution from the affiliated developer sufficient to achieve viable rates, RWSL acted imprudently prior to coming to the [AUC] for approval of its initial rate base";[305] (3) "[i]n light of this imprudence, the [AUC] has discretion to reduce RWSL's rate base to reflect the levels necessary to achieve viable rates";[306] and (4) "the reduction in RWSL's rate base will be achieved by deeming a significantly higher aggregate contribution amount than proposed by RWSL."[307]

300 *Ibid* at para 2. The 2007-2008 GRA was filed in accordance with sections 61, 89-91 of the *Public Utilities Act*, RSA 2000, c P-45 [*PUA*].

301 Decision 2011-061, *ibid*. The 2007-2010 GRA was filed in accordance with sections 89-91 of the *PUA*, *ibid*.

302 *Ibid* at para 4. *Regional Water Services Ltd*: *2007-2008 Interim Rate Application*, EUB Decision 2007-099 (11 December 2007).

303 Decision 2011-061, *ibid* at para 233. The approved 2007 year-end rate base was determined as $19,781,843 (*ibid* at para 39).

304 *Ibid* at para 103.

305 *Ibid* at para 104.

306 *Ibid* at para 105.

307 *Ibid*.

The AUC allowed a more limited form of the RDDA than requested,[308] based on deemed developer contributions of $15 million for CIAC and a $25,500 per lot contribution (instead of $12,500) on a go-forward basis.[309] If the AUC determines that the RDDA is growing at an unmanageable level, the AUC may direct RWSL to further increase the levels of deemed contributions. In reaching this decision, the AUC considered the following: (1) the RDDA "should not be treated as a catch-all for fixing errors";[310] (2) deferral accounts should not correct adjustments relating to "utility mismanagement or imprudence";[311] (3) the RDDA can assist with "intergenerational equity by not putting an excessive burden on the existing customers";[312] (4) by 2026 the RDDA would reach $119.3 million and RWSL would still only have 60 percent recovery of its revenue requirement; it is not "reasonable for RWSL to accumulate this amount in the RDDA and expect to recover it from customers over time";[313] (5) in approving the RDDA, the AUC "must balance the interests of RWSL with the interests of customers";[314] (6) to ensure a reasonable RDDA there must be a sufficient CIAC and per lot contribution from the developer; (7) the balance in the RDDA should be amortized once RWSL passes the breakeven point and is no longer experiencing a revenue shortfall, which should occur prior to the sale of all 875 lots or at the sale of lot 875;[315] and (8) the balance in the RDDA should not be excessive; it should be recoverable "from existing customers over a maximum 24-month period, without placing an undue burden on customers."[316]

d. Decision

The AUC: (1) found RWSL's plant-in-service amounts to be sufficiently accurate; (2) found the capacity of the water system and plant held for future use reasonable and that their development could not have been economically staged in lower capacity increments, and that the risk of capacity utilization is accounted for in the contribution that RWSL should have required from the developer;[317] (3) determined that RWSL failed to obtain a sufficient contribution from the developer and as such its rate base must be reduced by the amount of a substantial deemed CIAC; (4) accepted the $2 million market valuation of the water licence;[318] (5) found the capital structure reasonable and that the cost of debt should be set in reference to the actual interest paid; (6) accepted RWSL's operating expenses, however, denied RWSL's proposal to establish a deferral account for regulatory costs; (7) denied the request for a RDDA on the terms proposed by RWSL; (8) determined that the average use per household per month should be 30 m^3;[319] and (9) ordered the rates to be a $70 per month

308 *Ibid* at para 231. RWSL proposed to use the developer's per lot contributions of $12,500 related to tie-in fees to reduce the RDDA amounts starting in 2009 and continue until all 875 lots had been sold. RWSL proposed that the balance that remained in the RDDA, once the plant is fully utilized, would be amortized.

309 *Ibid* at para 234. These additional contribution amounts can either be allocated to specific property accounts or amortized as a whole at RWSL's 2.69 percent per year composite depreciation rate.

310 *Ibid* at para 216, citing *Calgary (City of) v Alberta (Energy and Utilities Board)*, 2010 ABCA 132, 477 AR 1 at para 69.

311 Decision 2011-061, *ibid* at para 218.

312 *Ibid*.

313 *Ibid* at para 227.

314 *Ibid* at para 228.

315 *Ibid* at para 232.

316 *Ibid*.

317 *Ibid* at paras 75-76.

318 *Ibid* at para 115.

319 *Ibid* at para 257.

fixed charge with a three-tiered system based on usage with a 2 percent annual increase to account for inflation.[320]

III. DUTY TO CONSULT

A. SUPREME COURT OF CANADA

1. *RIO TINTO ALCAN INC V CARRIER SEKANI TRIBAL COUNCIL*[321]

Of significance from a regulatory perspective is that this decision sets out where the duty to consult can be considered in the context of a facility application before a regulatory tribunal, and what relief such as tribunal can grant having considered the duty to consult. Any person that is interested in this decision should also review the Federal Court of Appeal decision of *Standing Buffalo Dakota First Nation v Enbridge Pipelines Inc.*[322]

a. Application

In this appeal, the British Columbia Utilities Commission (BCUC) determined that it had the power to consider the adequacy of consultation with Aboriginal groups but found that the duty to consult was not triggered because a 2007 Energy Purchase Agreement (EPA) could not possibly adversely affect any Aboriginal rights. The British Columbia Court of Appeal held that the honour of the Crown obliged the BCUC to decide the consultation issue.

The Court of Appeal did not criticize the BCUC's adverse impacts finding, rather it found that the BCUC wrongly decided the issue as a preliminary matter, which properly belonged in a full hearing of the merits. Rio Tinto Alcan Inc (Alcan) and BC Hydro successfully obtained leave to appeal the Court of Appeal decision to the Supreme Court of Canada.

b. Background

"In the 1950s, the government of British Columbia authorized the building of the Kenney Dam"[323] and reservoir on the Nechako River, an area that the member First Nations of the Carrier Sekani Tribal Council (Carrier Sekani) used and to which they claimed Aboriginal rights. The First Nations were not consulted when the dam was first authorized and built.

Beginning in 1961, EPAs governed the purchase and sale of excess power generated by the Kenney Dam, as between BC Hydro and Alcan (the constructor and operator of the dam). In 2007, BC Hydro and Alcan sought the BCUC's approval of the 2007 EPA. Carrier Sekani asserted that the 2007 EPA should be subject to consultation pursuant to section 35 of the *Constitution Act, 1867*.[324]

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320 *Ibid* at paras 273, 279.
321 2010 SCC 43, [2010] 2 SCR 650.
322 2009 FCA 308, [2010] 4 FCR 500, all leaves to appeal to SCC refused: 33462, 33480, 33481, 33482 (2 December 2010).
323 *Ibid* at para 1.
324 (UK), 30 &31 Vict, c 3, reprinted in RSC 1985, App II, No 5.

c. Key Findings

With respect to the duty to consult, the Supreme Court of Canada indicated that:

(i) The Crown's duty to consult arises when the three elements of the test set out in *Haida Nation v British Columbia (Minister of Forests)*[325] are met, namely: (1) the Crown has knowledge, actual or constructive, of a potential Aboriginal claim or right; (2) the Crown contemplates conduct or a decision; and (3) the contemplated conduct or decision may adversely affect an Aboriginal claim or right.

(ii) The duty to consult is triggered by an appreciable adverse effect stemming from *current* Crown conduct or decisions that has a causal relationship between the proposed government conduct or decision and a potential for adverse impacts on Aboriginal claims or rights.

(iii) Adverse impacts may extend to any effect that may prejudice a pending Aboriginal claim or right. An underlying infringement is not an adverse impact for the purposes of determining whether a particular government decision gives rise to a duty to consult. Prior and continuing breaches, including prior failures to consult, will only trigger a duty to consult if the present decision has the potential of causing a *new* adverse impact on a current claim or right.[326]

(iv) Accordingly, Carrier Sekani failed to establish that the duty to consult arose. The 2007 EPA would not cause physical impacts on the Nechako River or the fishery, and there would be no organizational or policy impacts that could possibly adversely affect the rights of the Carrier Sekani.

With respect to the role of a particular tribunal in Crown consultation:

(v) The role of a particular tribunal in Crown consultation depends on the specific duties and powers that have been granted to it.[327]

(vi) The Legislature may have delegated to a tribunal the Crown's duty to consult, or may require a tribunal to determine if adequate consultation has taken place as part of its overall decision-making process when considering a specific regulatory application. Relevant considerations to determine a tribunal's role include whether the tribunal has the power to consider questions of law, the scope of its remedial powers, and its public interest mandate.

(vii) A tribunal with the power to consider the adequacy of consultation "should provide whatever relief it considers appropriate in the circumstances, in accordance with the remedial powers expressly or impliedly conferred" on it by legislation.[328]

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325 2004 SCC 73, [2004] 3 SCR 511.
326 These past or underlying infringements may be remedied in other ways, including the awarding of damages. *Ibid* at para 49.
327 *Ibid* at para 55.
328 *Ibid* at para 61.

> Accordingly, the BCUC had the power to consider Crown consultation by virtue of its general authority to determine questions of law and its power to determine whether the 2007 EPA was in the public interest.

d. Decision

On 28 October 2010 the Supreme Court of Canada allowed the appeal by confirming the BCUC's determination that the 2007 EPA was in the public interest. The Court ruled that the BCUC acted reasonably when it found that the 2007 EPA did not give rise to any new impacts that triggered the Crown's duty to consult. The historical infringements associated with the original construction of the dam and reservoir were not sufficient to trigger the duty to consult.

B. FEDERAL COURT

1. *SWEETGRASS FIRST NATION V CANADA (AG)*[329]

In this decision, the Federal Court denied an application staying the effects of a NEB hearing order due to the Crown's alleged failure to properly consult on the basis that the Federal Court of Appeal now has plenary powers over NEB-related applications.

a. Application

The Sweetgrass First Nation (SFN) and the Moosomin First Nation (the Applicants) were seeking a remedy against the NEB in conjunction with a judicial review of a decision made by the Attorney General of Canada (AG) not to consult directly with the Applicants regarding the TransCanada Keystone XL Pipeline GP Ltd Pipeline Project (the Keystone Project). However, in light of major reforms to the *Federal Courts Act*,[330] effective in 1992, the Federal Court of Appeal now has original exclusive judicial review jurisdiction to hear applications concerning the NEB.

b. Background

The AG had allegedly informed the Applicants that it would rely on the NEB hearing to fulfill the Federal Crown's consultations obligations.

The Applicants claimed that the Keystone Project affected their rights and requested the following relief before the Federal Court: (1) a declaration that it was not an appropriate process to discharge the Crown's duty to consult with the Applicants through the NEB hearing; (2) a declaration that the AG must consult with the SFN prior to the NEB granting any permits for the construction and operation of the Keystone Project pipeline; (3) a stay of NEB hearing order OH-1-2009 until the Applicants have been consulted by the AG; and (4) a prohibition on the granting of a CPCN before consultations occurred between the AG,

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329 2010 FC 535, 365 FTR 254 [*Sweetgrass First Nation*].
330 RSC 1985, c F-7 [*FC Act*].

the relevant provincial Crowns, and the Applicants, and before agreeing to an appropriate mitigation and compensation plan.[331]

c. Key Findings

Jurisdiction allocated to the Federal Court under section 18(1)(a) of the *FC Act* is subject to the provisions in section 28 of the *FC Act*. Section 28 states that the Federal Court of Appeal, and not the Federal Court, has jurisdiction to hear applications for judicial review made in respect of a number of federal entities, including the NEB. The Federal Court maintained that for those entities listed in section 28 of the *FC Act*, "the [Federal Court of Appeal] was given the same powers as the Federal Court including the power to grant interim stays."[332] Accordingly, the "intent of the reform was to ensure that the Federal Court of Appeal has plenary powers in respect of listed entities" and to avoid overlap in jurisdiction.[333]

In arriving at its decision, the Federal Court took into account the Federal Court of Appeal's decision in the *Evangelical Fellowship of Canada v Canadian Musical Reproduction Rights Agency*[334] case. In that case, the Evangelical Fellowship of Canada (the Fellowship) sought a writ of prohibition to prevent the start of the Copyright Board's scheduled hearing. The Federal Court of Appeal ruled that it had exclusive jurisdiction to consider the Fellowship's application based on the combined operation of sections 18 and 28 of the *FC Act*. The Federal Court rejected the Applicants' proposition that the *Evangelical Fellowship* case should be distinguished from their case.

The Federal Court also maintained that the decision sought to be reviewed by the Applicants is contained in a letter[335] addressed to the SFN by the Director General, Policy, Major Projects Management Office (MPMO) "informing them how the Crown's duty to consult Aboriginal groups would be exercised" for the Keystone Project.[336] The Federal Court noted, accordingly, that the Applicants were still entitled to pursue their judicial review application against the MPMO decision, a remedy which the Federal Court would have jurisdiction to grant.

d. Decision

The Federal Court held that it lacked jurisdiction to entertain the application and the application for judicial review was dismissed.

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331 *Sweetgrass First Nation*, *supra* note 329 at para 325.
332 *Ibid* at para 29.
333 *Ibid*.
334 (1999), 1 CPR (4th) 497 (FCA) [*Evangelical Fellowship*].
335 Letter from Anne-Marie Erickson to all parties to the GH-3-2010 Proceeding and Spectra Energy Midstream Corp (7 January 2011) [SDLC Letter].
336 *Sweetgrass First Nation*, *supra* note 329 at para 10.

IV. JURISDICTION

A. NATIONAL ENERGY BOARD

1. *DECISION ON NOTICE OF MOTION FROM THE SOUTH DAWSON LANDOWNERS COMMITTEE/CANADIAN ASSOCIATION OF ENERGY AND PIPELINE LANDOWNER ASSOCIATIONS*[337]

This decision confirms the relevant test about when a pipeline within the province does or does not fall under federal jurisdiction.

a. Application

The South Dawson Landowners Committee/Canadian Association of Energy and Pipeline Landowner Associations (SDLC/CAEPLA) filed a motion before the NEB seeking a declaratory order stating that the Bissette Pipeline is properly within federal jurisdiction and, hence, subject to regulation by the NEB.

b. Background

This application was filed in the context of the NEB's proceeding regarding the Dawson Project.[338] The NEB declined to hear the motion as part of the Dawson Project proceedings but invited the interested parties to comment on whether it should establish a process to consider the motion.

c. Key Findings

Since the Bissette Pipeline would be located wholly within the province of British Columbia, it would be within provincial jurisdiction unless brought under federal jurisdiction by one of the tests set out by Supreme Court in *Westcoast Energy Inc v Canada (National Energy Board)*.[339] In that case, the Supreme Court identified two ways that a pipeline within a province falls under federal jurisdiction under the *Constitution Act, 1867*: the pipeline may be part of a federal work or undertaking, or it may be integral to a federal work or undertaking.

The NEB concluded that despite SDLC/CAEPLA's submission that the Bissette Pipeline and the Dawson Plant form one single federal undertaking, the Dawson Plant had been neither approved nor constructed. Accordingly, the Bissette Pipeline did not form part of any federal work or undertaking, nor was it integral to any federal work or undertaking.[340]

d. Decision

The application was dismissed.

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337 SDLC Letter, *supra* note 335.
338 See discussion of this proceeding at Letter Decision, *supra* note 65.
339 [1998] 1 SCR 322.
340 SDLC Letter, *supra* note 335 at 5.

V. REVIEW AND VARIANCE/REHEARING

A. ALBERTA COURT OF APPEAL

1. *MILNER POWER INC V ALBERTA (ENERGY AND UTILITIES BOARD)*[341]

This decision considers when it would be appropriate for a regulatory tribunal to decline to hold a hearing into a complaint, if it does not consider the complaint to be frivolous, vexatious, or trivial, but nevertheless determines that it does not otherwise warrant an investigation or hearing. In addition, the decision considers the extent to which deference is given to the Alberta Electric System Operator (AESO) as far as its duty of rule development is concerned.

1. Application

The appellant, Milner Power Inc (Milner),[342] appealed a decision of the EUB summarily dismissing its complaint under sections 25 and 26 of the *EUA* against the Line Loss Rule developed by the AESO. Milner alleged that the "Line Loss Rule did not comply with the requirements of the *Transmission Regulation*[343] … and that it was otherwise unjust and unreasonable."[344]

Leave to appeal was granted on the grounds of whether the EUB erred in: (1) "identifying and applying the test under section 25(4) of the [*EUA*] to summarily deny Milner a hearing into its complaint, particularly where the Board considers the complaint is not frivolous, vexatious or trivial"; and (2) "adopting a test under section 25(4) by failing to properly consider sections 19(1)(a) and 19(2)(d) of the [*T-Reg*] and improperly deferring to the AESO's discretion."[345]

b. Background

Milner operates an electricity generator, delivering energy to Alberta's interconnected electrical system. Line losses create significant costs which are primarily borne by generators.

The AESO Line Loss Rule challenged by Milner in this appeal changed the calculation method for the determination of line losses from a tariff-based approach to a rule-based loss factor approach. In Milner's 2005 complaint to the EUB under sections 25 and 26 of the *EUA*, it raised concerns that (1) the proposed Line Loss Rule "had not been adequately reviewed"; (2) the AESO had "failed to study the use of an 'average MW in' approach" which Milner had advocated; (3) "the Line Loss Rule and the AESO's conduct in

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341 2010 ABCA 236, 482 AR 327 [*Milner Power v EUB*].
342 Milner Power Inc is a wholly owned subsidiary of Maxim. Milner Power Inc, "HR Milner Generating Station," online: Milner Power Inc <http://www.milnerpower.ca/index.html>.
343 Alta Reg 86/2007 [*T-Reg*].
344 *Milner Power v EUB*, *supra* note 341 at para 2.
345 *Ibid* at para 3.

implementing the Rule were unjust, unreasonable, unduly preferential, … and inconsistent" with the *EUA* and the *T-Reg*; (4) while the Line Loss Rule "recovers the correct amount of transmission losses on an aggregate or global basis, it failed in many cases to recover the correct amounts on a location-specific basis," as required by the *T-Reg*; and (5) the AESO's approach did not "fairly or accurately reflect the benefits derived from those generators whose output creates a net reduction in system losses, thereby breaching the [*T-Reg*] and creating prejudice."[346]

In denying Milner's request to set the complaint down for a hearing, the EUB relied on section 25(4) of the *EUA*, which authorizes the EUB to decline to hold a hearing into a complaint if it considers the complaint to be "frivolous, vexatious, trivial *or otherwise does not warrant*" an investigation or hearing.[347]

c. Key Findings

First, the Alberta Court of Appeal found that section 25(4) "as a whole contemplates an investigation or hearing of a complaint which, on its face, has arguable merit.… [A]n interpretation that provides for an effective complaint process is preferable, when one considers the significance of an [AESO] rule or fee. Those rules and fees are imposed without right to a hearing, and the threshold for the complaint process should not be narrowly construed."[348] In other words, the EUB can only decline to pursue a complaint when the complaint has no arguable merit; conversely, having any arguable merit is a sufficient threshold for the complaint to be considered. The fact that the EUB did not find Milner's complaint frivolous, vexatious, or trivial required the EUB to consider its complaint in this case.[349]

Second, the Court indicated that the fact that responsibility for setting a rule has been delegated to the AESO does not insulate the AESO's exercise of that power from the complaint process. The AESO's decisions at this early stage do not require deference from the regulator, and to accord them deference (and thereby bypass investigation) would "completely undermine" the "legislative safeguard."[350]

d. Decision

The appeal was allowed, the decision of the EUB vacated, and the matter remitted to the tribunal to further investigate, or to hold a hearing, to determine whether there was a contravention of section 19 of the *T-Reg*, as alleged. An oral hearing on this matter is currently set down before the AUC to commence on 19 October 2011.[351]

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346 *Ibid* at paras 8-9.

347 *EUA*, *supra* note 192, s 25(4) [emphasis added].

348 *Milner Power v EUB*, *supra* note 341 at para 44.

349 The Court also added that the EUB's invitation of other stakeholders to make submissions regarding whether Milner's complaint should receive a hearing or investigation was unnecessary, "set an additional barrier to the decision to investigate or hear a complaint, and introduced an element of potential unfairness as it invited input from others who would benefit if the EUB declined to investigate or hold a hearing." *Ibid* at para 59.

350 *Ibid* at para 52.

351 AUC Proceeding 790, Application Number 1606494.

B. ENERGY RESOURCES CONSERVATION BOARD

1. *COMPTON PETROLEUM CORPORATION AND DARIAN RESOURCES LTD: SECTION 39 AND 40 REVIEW OF SEVEN WELL LICENCES, TWO PIPELINE LICENCES, AND ONE FACILITY LICENCE — ENSIGN, PARKLAND NORTHEAST, AND VULCAN FIELDS*[352]

This decision considers when interveners would qualify as "special needs" individuals that may have an enhanced susceptibility to impacts.

a. Application

Three individuals requested a review hearing pursuant to sections 39 and 40 of the *ERCA* with respect to Compton Petroleum Corporation and Darian Resources Ltd's (collectively, Compton) seven well licences, two pipeline licences, and one facility licence that were initially issued without hearings.

b. Background

The three individuals requesting the review and variance submitted that they were special needs individuals who had enhanced susceptibility to emissions from oil and gas facilities. Therefore, they had been or would be directly and adversely affected by decisions regarding facilities near their residence or within tens of kilometres from lands they own or lease. The ERCB determined that information regarding these individuals' special needs was not available at the time the facility applications were initially approved. The ERCB decided the individuals met the test for a review hearing and decided to hear all the licence applications at one hearing.[353]

Prior to the start of the hearing, the individuals withdrew their participation and evidence from the hearing. The ERCB decided to conduct the hearing on its own behalf with the presence of one intervener, a freehold landowner. The ERCB issued a lengthy Appendix setting the background to this hearing and the withdrawal of the individuals. This Appendix shows the extent to which the ERCB tried to understand and address the relevant individual's concerns.

c. Key Findings

With regard to the special needs condition, the ERCB determined that whether "special needs"[354] exist in relation to a proposed development depends on all the circumstances, including whether there is "a nexus between the proposed activity or development and the circumstances of the special needs individual."[355] Given that the emissions from the facilities

352 ERCB Decision, 2011 ABERCB 008 (1 March 2011).
353 *Ibid* at paras 2-3.
354 The ERCB is of the view that the special needs provision operates to identify those persons who require assistance in the event of an evacuation or require other protective action in the event of an incident. *Ibid* at para 67.
355 *Ibid* at para 68.

in question were "not likely to exist in concentrations that would affect human health, even for highly sensitive individuals," the individuals would not fall within the special needs category.[356] The ERCB's normal consultation and notification requirements were sufficient for these individuals.

d. Decision

The ERCB confirmed that the licences were "properly issued and in good standing, without any change, alteration, or variance in the terms."[357] Compton was also directed to make an application to the ERCB within a month from the issuance of this Decision to amend the facility licence to reflect the routine venting of gas that would take place at the facility.

2. *GRIZZLY RESOURCES LTD: SECTION 39 AND 40 REVIEW OF WELL LICENCES NO 0404964 AND 0404965 — PEMBINA FIELD*[358]

This is a summary of the numerous proceedings that finally led to a determination that the relevant sour well licences remained in good standing.

a. Application

Given direction from the Alberta Court of Appeal, the ERCB convened a review hearing related to whether Grizzly Resources Ltd's (Grizzly) well licences remained in good standing.

b. Background

On 27 June 2008, "Grizzly applied to the ERCB to obtain licences to drill two oil wells from a surface location of Legal Subdivision (LSD) 7, Section 5, Township 50, Range 6, West of the 5th Meridian, to bottomhole locations of LSD 9-5-50-6W5M and LSD 14-5-50-6W5M. The wells would target production from the Nisku Formation and would contain hydrogen sulphide (H_2S)."[359]

Three parties filed objections to Grizzly's applications. The ERCB "decided that these parties were not entitled to the participatory rights set out in Section 26(2) of the [*ERCA*] and therefore dismissed their objections," and issued the Well Licences No 0404964 and 0404965 on 28 November 2008.[360]

The three parties "subsequently filed review applications requesting that the [ERCB] reconsider its decision to dismiss their objections and direct that a hearing be held. The [ERCB] denied their review applications on the basis that they had not established how or

356 *Ibid* at para 70.
357 *Ibid* at para 1.
358 ERCB Decision 2010-028 (13 July 2010) [Decision 2010-028].
359 *Ibid* at 1.
360 *Ibid*.

why their rights may be directly and adversely affected by the ERCB's approval of the Grizzly applications."[361]

From January to February 2009, Grizzly drilled the wells. After the wells were drilled, the three parties applied to the Alberta Court of Appeal for leave to appeal the ERCB's decision that denied them a hearing. The Court granted leave to the three parties, who went on to have a successful appeal[362] and vacated the ERCB's decision to deny a hearing.

The Court remitted the matter to the ERCB "for reconsideration and redetermination with certain directions, including that the [three parties] '…be accorded standing to be heard on the merits … under the provisions of each of ss. 39 and 40 of the [*ERCA*].'"[363]

Further, the Court directed:

> The fact that the wells have now been drilled shall not be treated as a limit on ultimately concluding that Grizzly should not be permitted to operate them, or if in operation at the time of the rehearing, that it cannot be required to shut them down or that the right to operate cannot be made subject to appropriate conditions to be devised by the ERCB based on the evidence heard during the rehearing.[364]

With this direction in mind, the ERCB held the review hearing that is dealt with in this decision.

After *Kelly*, the ERCB also made certain corrections to *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry*[365] and to the *ERCBH2S: A Model for Calculating Emergency Response and Planning Zones for Sour Gas Wells, Pipelines, and Production Facilities*.[366]

"Since the wells had already been drilled, both Grizzly and the Review Applicants submitted that the focus of the hearing should be on issues that may arise during the production and servicing of the wells."[367]

"Grizzly noted that none of the interveners reside within the EPZs for any of the drilling, completion, servicing, suspended, or production phases of the wells."[368]

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361 *Ibid*.
362 *Kelly v Alberta (Energy Resources Conservation Board)*, 2009 ABCA 349, 464 AR 315 [*Kelly*].
363 Decision 2010-028, *supra* note 358 at 2, citing *Kelly*, *ibid* at para 54.
364 Decision 2010-028, *ibid*, citing *Kelly*, *ibid*.
365 ERCB, *Directive 071: Emergency Preparedness and Response Requirements for the Petroleum Industry* (Calgary: ERCB, 2008).
366 Michael J Zelensky & Brian W Zelt, *ERCBH25: A Model for Calculating Emergency Response and Planning Zones for Sour Gas Wells, Pipelines, and Production Facilities*, Vol 3: User Guide, Version 1.20 (Calgary: ERCB, 2010).
367 Decision 2010-028, *supra* note 358 at 2.
368 *Ibid* at 3.

c. Key Findings

In reaching its conclusion, the Board noted that:

(i) Not one of the three parties resided or had land within the EPZs. According to Grizzly, the production EPZ for the wells was 0.49 km; the three parties' residences were 2.5 to 5.5 km outside the boundary of the EPZs. "Notwithstanding where they resided, an operator is required to deal with the safety of people both within and outside the EPZ";[369]

(ii) The evidence presented to the Board did "not demonstrate that any of the interveners [were] at risk from these wells."[370] Grizzly adhered "to the ERCB's requirements for mitigating the risks of potential harm to public safety and the environment.… [I]n order to produce from these wells, Grizzly will have to apply for the associated facilities, such as pipelines, batteries, and any water production and injection wells. Such future applications would be the subject of further consideration by the ERCB";[371]

(iii) "[T]he drilling, completion, and testing of these wells were conducted safely and without incident and were in compliance with the ERCB requirements";[372]

(iv) Grizzly used "best practices" in calculating H_2S levels; the fact that "the H_2S levels encountered were higher than predicted does not … demonstrate anything" or inform the Board about the ongoing operation of these wells;[373]

(v) Two of the three parties "did not establish a connection between their pre-existing health conditions and these wells";[374]

(vi) "Grizzly's emergency response planning for both the drilling and production phases meets the ERCB's requirements [and] … adequately takes into account the safety of individuals in the area of the wells in the event of an incident."[375]

d. Decision

The ERCB was satisfied that the approval of the two wells was in the public interest, and found that the licences for these wells remained in good standing.

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369 *Ibid* at 6.
370 *Ibid*.
371 *Ibid*.
372 *Ibid*.
373 *Ibid* at 6-7. In fact, having established the actual H_2S content of the wells, Grizzly properly used that data to develop its ERP for the completion, production, and servicing phases of operations. In addition, the Board notes that the Review Applicants' concern is further mitigated since the flow rate actually achievable by the wells is lower than that used in the determination of the EPZ sizes prior to drilling.
374 *Ibid* at 7.
375 *Ibid*.

VI. SURFACE RIGHTS

A. SUPREME COURT OF CANADA

1. *SMITH V ALLIANCE PIPELINE LTD*[376]

This decision is interesting as it provides the message that industry should think twice about taking (what may have been viewed as) an unreasonable position towards a landowner.

a. Application

A landowner appealed certain costs awards that were upheld by the Federal Court on judicial review but set aside by the Federal Court of Appeal.

b. Background

This case dealt with a dispute about manure spread by a landowner on a strip of his land that Alliance Pipeline Ltd (Alliance) has an obligation to reclaim. Contrary to an agreement, Alliance did not reclaim the land in a timely manner, and also refused to fully compensate the landowner who took on that obligation. The landowner "turned to statutorily mandated arbitration for what was meant to assure an expeditious resolution of the dispute."[377] Two Arbitration Committee hearings, one Alberta Court of Queen's Bench action, one judicial review, and one appellate review proceeding later, each with associated significant legal fees, the landowner finally obtained compensation.[378]

The second Arbitration Committee was appointed after the proceedings before the first Arbitration Committee were aborted due to a loss of quorum. The second Arbitration Committee's decision granted the landowner's claim for his costs before the first Arbitration Committee, compensation for most of his reclamation work and $16,222.57 in solicitor-client costs. These awards were upheld by the Federal Court on judicial review, but set aside by the Federal Court of Appeal.

c. Key Findings

The Supreme Court of Canada held that the governing standard of review is reasonableness, when determining the overarching question that was before the second Arbitration Committee, of whether "costs" in section 99(1) of the *NEB Act*[379] "refers solely to expenses incurred by an expropriated owner in the proceedings before it."[380] In this case,

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376 2011 SCC 7, [2011] 1 SCR 160 [*Smith v Alliance*].
377 *Ibid* at para 2.
378 *Ibid* at para 3.
379 *NEB Act, supra* note 23, s 99(1) reads:

> Where the amount of compensation awarded to a person by an Arbitration Committee exceeds eighty-five per cent of the amount of compensation offered by the company, the company shall pay all legal, appraisal and other costs determined by the Committee to have been reasonably incurred by that person in asserting that person's claim for compensation.

380 *Smith v Alliance, supra* note 376 at para 22.

the Committee was interpreting its home statute. Under *Dunsmuir v New Brunswick*,[381] "this will usually attract a reasonableness standard of review."[382]

The Supreme Court held that the relevant words of section 99(1) made it plain that the Committee was bound to order Alliance to pay "*all legal, appraisal and other costs determined by the Committee to have been reasonably incurred by [Smith] in asserting [his] claim for compensation*."[383] "The Committee's reasoning in interpreting and applying this provision [was] coherent" because: (1) the Committee "found that the Court of Queen's Bench action was directly related to [the] attempt to obtain compensation from Alliance,"[384] concluding that these costs were incurred reasonably, and accordingly, logically flow from its findings of fact;[385] and (2) "the Committee decided that the first panel's loss of a quorum resulted in the nullification of some but not all of the original proceedings."[386] Accordingly, the Committee's logic in awarding a portion of the costs that were incurred during the first arbitral proceedings "is consistent with the record" and not unreasonable.[387]

The landowner was awarded costs throughout, on a solicitor-client basis, for the following reasons: (1) "in the context of modern expropriation law, where statutes authorize awards of '*all* legal, appraisal *and other* costs,' Canadian jurisprudence and doctrine demonstrate that 'costs on a solicitor-and-client basis should generally be given'";[388] (2) "awarding costs on a solicitor-client basis accords well with the object and purpose" of the *NEB Act*, which is reflected in section 75;[389] (3) in the circumstances, "justice can only be done by a complete indemnification for costs";[390] and (4) Smith was not to be made to bear the costs of what was "clearly a test case" for Alliance.[391]

d. Decision

On 11 February 2011, the Supreme Court restored the decision of the second Arbitration Committee. The Court further held that the decision "was subject to intervention on judicial review only if it was found to be unreasonable."[392]

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381 2008 SCC 9, [2008] 1 SCR 190 [*Dunsmuir*].
382 *Smith v Alliance*, *supra* note 376 at para 28.
383 *Ibid* at para 47 [emphasis in original].
384 *Ibid* at para 44.
385 *Ibid*.
386 *Ibid* at para 45.
387 *Ibid*.
388 *Ibid* at para 74, citing *Bayview Builder's Supply v British Columbia (Minister of Transportation and Highways)*, 1999 BCCA 320, 23 RPR (3d) 193 at para 3 [emphasis in *Smith v Alliance*].
389 *Smith v Alliance*, *ibid* at para 75.
390 *Ibid* at para 76, citing *Foulis v Robinson* (1978), 21 OR (2d) 769 at 776 (CA).
391 *Smith v Alliance*, *ibid* at para 77. In addition to the present case, Alliance was involved in 19 other arbitration proceedings before the First Committee. Those proceedings were also cut short by the resignation of a committee member upon appointment to the Bench, and resulting loss of quorum.
392 *Ibid* at para 5.

B. SURFACE RIGHTS BOARD

1. *MONTANA ALBERTA TIE LTD V KAMPERT*[393]

In this decision, the Alberta Surface Rights Board (SRB) ruled on its authority to grant right of entry for access roads related to power transmission lines.

a. Application

Montana Alberta Tie Ltd (MATL) applied for a right of entry order, to obtain access to the land in question "for or incidental to the construction, operation or removal of a power transmission line."[394]

b. Background

The SRB's Board Administration initially rejected MATL's application because of the inclusion of access roads in the survey plans attached to its application.[395] Following MATL's submissions on the SRB's authority to grant right of entry for temporary access roads, Board Administration filed the application as it was, advising MATL that the SRB Panel would make the ultimate determination.

MATL made several arguments with respect to SRB's authority to grant right of entry for temporary access roads, including: (1) such authority was derived from section 12(1)(d) of the *SRA*, which states that no operator has a right of entry to any land for or incidental to the construction or operation of a power transmission line until the operator acquires consent or a right of entry order; and (2) the EUB's decisions approving MATL's permit and licence acknowledged the necessity of roadways, and "so denying the temporary access roads would 'effectively negate' (and therefore be inconsistent with)" those decisions.[396] For instance, EUB Decision 2008-006 stated that "MATL would need to construct few new access roads, most of which would be for construction, not maintenance."[397]

The Respondents pointed to the lack of an approval from the EUB or the AUC that specifically addressed the locations of the access roads and argued that MATL should apply to the AUC for a variation in its permit to include the access roads.[398]

c. Key Findings

The SRB ruled that it does not have the jurisdiction to grant right of entry orders for access roads related to a power transmission line. Following a statutory interpretation analysis the SRB found that, while it was arguable that a road could be incidental to a

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393 SRB Decision 2010/0775 (24 November 2010) [Decision 2010/0775].
394 *Surface Rights Act*, RSA 2000, c S-24, s 12(1)(d) [*SRA*].
395 The previous SRB decision of *Air Products Canada Ltd Right of Entry Order*, SRB Decision 2009/0567 (16 December 2009), was provided to MATL in support of the Board Administration's ruling.
396 Decision 2010/0775, *supra* note 393 at 2.
397 *Ibid* at 3, citing *Montana Alberta Tie Ltd: 230-kV International Merchant Power Line Lethbridge Alberta to Great Falls Montana*, EUB Decision 2008-006 (31 January 2008).
398 Decision 2010/0775, *ibid*.

transmission line under section 12(1)(d), roads did not fall within the meaning of "incidental" in this case.[399]

First, the SRB considered that the granting to it of specific authority under section 12(3) to authorize right of entry for roadways related to well sites indicates that roads are not included within matters "incidental" to mining or drilling operations[400] and thus are not included in matters incidental to power transmission lines either.

The SRB further found that there is no equivalent to section 12(3) anywhere in the *SRA* with respect to roads for power transmission lines.[401] With access roads not included under section 12(1)(d) as "incidental" to the power transmission line, and no specific authority granted to the SRB under any other provision to grant an applicant right of entry, the SRB found that it did not have the authority to issue a right of entry order for roadways related to power transmission lines.

d. Decision

Accordingly, the SRB granted MATL right of entry only for those portions of land in its survey plan that were not identified as access roads, and required it to file a new plan of survey with the access roads removed.[402]

VII. STANDING AND PARTICIPANT FUNDING

A. ALBERTA COURT OF APPEAL

1. *KELLY V ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*[403]

This decision related to an intervener's entitlement to standing on a sour well licence application.

a. Application

The applicants sought leave to appeal an ERCB decision that denied them standing on an application to licence a sour gas well.

b. Key Findings

The Alberta Court of Appeal found that the "essential legal issue" was "whether a person who is contemplated by a corporate-level Emergency Response Plan but resides outside the

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399 *Ibid* at 6.
400 Sections 12(1)(a) and (b) of the *SRA* give the SRB the authority grant right of entry for "the removal of minerals … for or incidental to any mining or drilling operations," and "the construction of tanks, stations and structures for … a mining or drilling operation … or for or incidental to the operation of those tanks, stations and structures."
401 Decision 2010/0775, *supra* note 393 at 7.
402 *Ibid* at 5.
403 2010 ABCA 307, [2010] AJ no 1187 (QL) [*Kelly 2010*].

EPZ is entitled, as a matter of law, to standing."[404] In order to raise a reviewable issue of law, an applicant would likely have to demonstrate "that standing was compulsory in the circumstances (as in [*Kelly*[405]]), regardless of the magnitude of the risk that hydrogen sulfide concentrations would ever reach dangerous levels."[406]

c. Decision

Leave to appeal was allowed on the following questions:

> (a) Is a person who resides outside the Emergency Planning Zone, but within the zone where a potential exists for hydrogen sulfide levels of 10 ppm, directly and adversely affected as a matter of law, so as to be entitled to standing?
>
> (b) Did the ERCB err by holding that there was *no* evidence on the record to show that the applicants' medical conditions would give them a heightened sensitivity to oil and gas well operations in the vicinity of their properties, and if so is that an error of law?[407]

As of 26 May 2011, no decision on the merits has yet been issued by the Alberta Court of Appeal in this matter.

2. *KELLY V ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*[408]

The appeal that would follow from this leave to appeal decision would be interesting as it relates to when an intervener may be denied a costs award, and the power of ERCB Directives to interpret a section of the *ERCA*.

a. Application

The applicants sought leave to appeal a decision[409] of the ERCB denying them local intervener costs for a hearing in which they participated.

b. Background

Section 28 of the *ERCA* grants the ERCB authority to award costs to hearing participants. The ERCB denied the applicants' cost application under section 28, largely on the basis that the only evidence the interveners presented related to adverse impacts on their health, and that there was no evidence demonstrating adverse impacts on their land.

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404 *Ibid* at para 14.
405 *Supra* note 362.
406 *Kelly 2010*, *supra* note 403 at para 14 [footnote added].
407 *Ibid* at para 15.
408 2011 ABCA 19, [2011] AJ no 44 (QL) [*Kelly 2011*].
409 *Grizzly Resources Ltd: Section 39 and 40 Review of Well Licences No. 0404964 and 0404965 Pembina Field, Cost Awards*, ERCB Energy Cost Order 2010-007 (22 October 2010). See Decision 2010-028, *supra* note 358 for a discussion of the review hearing that was the subject of this costs application.

c. Decision

Without reasons, the Alberta Court of Appeal granted leave to appeal the ERCB's costs decision on the following grounds:

> 1. Is the Board's power to award costs limited to persons who are "local interveners" as defined by s 28(1) of the *Energy Resources Conservation Act*?
>
> 2. Does a formal Directive of the Board have the power to interpret a section of that *Act*, and compel the Board and others to follow that interpretation?
>
> 3. What is the proper interpretation of s 28(1) of that *Act*?
>
> (a) Must detriment or potential detriment be to the soil or improvements on the land, or can the detriment include interference with occupation, use or enjoyment of the land by people, plants, animals, or chattels (including danger to health)?
>
> (b) Are the relevant facts for that subsection tested or fixed at the time that the proceedings began, or during the proceedings, or only at the time of the costs application after the Board's substantive decision?[410]

A costs award was issued against the proponent on 9 March 2011 for its active opposition of this leave to appeal application,[411] however as of 27 May 2011, no decision on the merits has yet been issued by the Court in this matter.

3. *MAXIM POWER CORP V ALBERTA (UTILITIES COMMISSION)*[412]

This decision summarizes denial by the Alberta Court of Appeal of Maxim's appeal. The Court: (1) upheld the AUC's decision related to its jurisdiction in interpretation of *EUA* section 95, confirming the Minister's role being beyond that filled by the AUC; and (2) confirmed denial of Maxim's standing.

a. Application

The appellant, Maxim, appealed the AUC's decision,[413] arguing that the AUC misinterpreted section 95 of the *EUA* and erred in determining that Maxim did not have standing in an AUC hearing.

b. Background

Energy Smart Industrial (ESI), a municipally owned utility, sought the AUC's approval to build a power plant. Maxim (and others) applied for standing in the ESI hearing on the

410 *Kelly 2011*, *supra* note 408 at para 1.
411 See *Kelly v Alberta (Energy and Resources Conservation Board)*, 2011 ABCA 81, [2011] AJ no 231 (QL).
412 *Maxim Power v AUC*, *supra* note 206.
413 For further discussion of this decision, see Decision 2010-493, *supra* note 203.

basis that it would be affected by the decision because the electricity market in Alberta might be distorted by an approval of the power plant.

Section 95 of the *EUA* prohibits municipally owned utilities "from holding an interest in a generating unit without the Minister's authorization."[414] "The relevant parts of section 95 are intended to ensure that a municipality's interest in a generating unit is structured to prevent 'any … advantage … as a result of association with the municipality' (level playing field)."[415]

ESI had applied to the Minister under section 95 and judicial review of the procedures established by the Minister under section 95 was denied. The AUC held that it did not have the jurisdiction to consider the level playing field issues and undermine the integrity of the Minister's decision, which is not subject to the AUC's review. Since Maxim's only interest in the hearing related to these issues, the AUC denied Maxim standing.[416]

Maxim was granted leave to appeal the questions of whether the AUC erred in: (1) interpreting section 95 as being determinative of the issues that section 11 of the *HEEA* required to consider; and (2) denying Maxim standing.

c. Key Findings

The Alberta Court of Appeal applied the correctness standard of review, as the issue was a jurisdictional question wherein the tribunal had to "explicitly determine whether its statutory grant of power gives it the authority to decide a particular matter."[417]

The Court upheld the AUC's interpretation of section 95, and resulting denial of standing to Maxim, based largely on the following: (1) the fact that portions of section 95 give the Minister a special role beyond that filled by the AUC, "supports the view that the Legislature intended the Commission to have no role in this regard";[418] (2) for the AUC to reconsider the same matter assigned by section 95(12) would be contrary to the purpose of the *EUA* to provide "a framework so that the Alberta electric industry can … be effectively regulated in a manner that minimizes the cost of regulation";[419] (3) "[c]onsidering the same issue twice does not minimize costs or make for effective regulation. Nor does the possibility of conflicting decisions";[420] and (4) this interpretation does not undercut the requirement in section 3(1) of the *HEEA* that the AUC "'have regard for the purposes of the [*EUA*]' when considering an application for the construction of a generating unit. The Commission can do so by ensuring there has been compliance with section 95, which is accomplished by *Rule 007*."[421]

414 *Maxim Power v AUC*, *supra* note 206 at para 4. A generating unit is defined in section 1(1)(u) of the *EUA* as "the component of a power plant that produces … electric energy."

415 *Ibid* at para 5.

416 *Ibid* at paras 6-7.

417 *Ibid* at para 22, citing *Dunsmuir*, *supra* note 381 at para 59.

418 *Maxim Power v AUC*, *ibid* at para 40.

419 *Ibid* at para 41, citing *EUA*, *supra* note 192, s 5(h).

420 *Maxim Power v AUC*, *ibid*.

421 *Ibid* at para 42, referrring to AUC, *Rule 007: Applications for Power Plants, Substations, Transmission Lines, and Industrial System Designations* (Calgary: AUC, 2009).

d. Decision

Maxim's appeal was dismissed.

4. *SEMCAMS ULC V ALBERTA (ENERGY RESOURCES CONSERVATION BOARD)*[422]

The issue related to entitlement to standing based on protection of economic interests has come up in a diverse number of standing decisions. This decision clarifies that an applicant would have trouble appealing a regulatory tribunal's decision on standing on this ground, as such an appeal would constitute a question of mixed fact and law.

a. Application

The applicants, SemCAMS ULC (SemCAMS) and Husky, each sought leave to appeal from decisions of the ERCB denying them standing in an application by Celtic Exploration Ltd (Celtic) for an amendment to its facility licence to upgrade its sour gas compressor station to a sour gas processing plant (the Proposed Celtic Facility).

The applicants sought leave to appeal on the grounds that the ERCB erred by: (1) "determining that the rights or interests asserted by the applicants were not legally recognized and that they were not directly and adversely affected in accordance with section 26 of the [*ERCA*];[423] (2) failing to provide sufficient reasons as to how Celtic's consultation activities satisfied the ERCB's proliferation policy; (3) "denying standing notwithstanding potential negative impact of the waste stream of the KA plant";[424] and (4) failing to consider issues of public interest.

b. Background

In denying the applicants standing, the ERCB determined that they were actually seeking to protect their economic interests, "to prevent or limit competition and to maintain current revenue streams, and that these were not the kind of interests section 26 of the [*ERCA*] was designed to protect."[425]

The ERCB also found that Celtic's consultation with the applicants had been adequate, and that the "mere assertion of a physical change to the inlet stream was not itself a potential adverse impact."[426]

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422 2010 ABCA 397, 96 CPC (6th) 46.
423 *Ibid* at para 11.
424 *Ibid*. The KA Plant is a natural gas processing plant owned by Husky and operated by SemCAMS. Celtic is a customer of the KA Plant, which is located approximately 21 km from the proposed facility (*ibid* at para 2).
425 *Ibid* at para 4.
426 *Ibid* at para 10.

c. Key Findings

The Alberta Court of Appeal found that the ERCB's ruling that the applicants' interests in the proposed Celtic Facility were economic or commercial was a "determination of mixed fact and law," and therefore not reviewable on appeal.[427]

The ERCB concluded that the underlying purpose for the informational requirements in this case was "basically economic. In other words, no stand alone right was created in the circumstances."[428]

Finally, the Court held that the other grounds of appeal also raised questions of mixed fact and law, or in the case of the public interest argument, the ability to raise it depended on the Applicants having standing as it was challenging the merits of the underlying application.[429]

d. Decision

Leave to appeal was denied on all grounds.

B. ENVIRONMENTAL APPEALS BOARD

1. *DONKERSGOED AND ALL V DIRECTOR, SOUTHERN REGION, ENVIRONMENTAL MANAGEMENT, ALBERTA ENVIRONMENT, RE: DOUGLAS J BERGEN & ASSOCIATES LTD*[430]

This decision is part of a recent line of authority in which the Alberta Environmental Appeals Board (AEAB) has emphasized that potential impacts which are speculative and remote are not sufficient to establish a party's directly affected status.[431]

a. Application

The AEAB received Notices of Appeal from several parties, including Donkersgoed and Donkersgoed Feeders Ltd, appealing the AENV Approval to Douglas J Bergen & Associates Ltd (the Approval Holder) under the *Water Act* that authorized the construction and operation of works for Phase 1 of the Seasons subdivision in Coaldale, Alberta. The Approval altered the amount and direction of flow of water to an unnamed drainage tributary to the Malloy Drain and Stafford Reservoir. The Approval mandated zero release of any storm water from the Seasons subdivision.[432]

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427 *Ibid* at para 15.
428 *Ibid* at para 16.
429 *Ibid* at para 20.
430 (20 December 2010), Appeal Nos 10-003, 005 & 006-D (AEAB) [*Donkersgoed*].
431 See also *Williamson v Director, Central Region, Regional Services, Alberta Environment, re: Lacombe County* (18 October 2010), Appeal No 10-017-D at para 38 (AEAB), where the AEAB held that it could not "rely on a speculative event as a basis to find an appellant directly affected; it required some evidence that the event could [actually] occur."
432 *Donkersgoed, supra* note 430 at paras 1, 14.

b. Key Findings

The AEAB confirmed that "the determination of standing cannot be based on speculation."[433] A possibility that an Approval Holder would contravene its Approval is nothing more than speculation. "In assessing directly affected, the [AEAB] is required to consider the approval … as issued and the terms and conditions included that are intended in that approval … to protect the environment and the public. It is presumed the approval holder will comply with all of the conditions in the approval or licence."[434]

c. Decision

Based on the presumption of compliance and the lack of evidence demonstrating the potential for non-compliance, the appellants were not directly affected and their appeals were dismissed.

C. NATIONAL ENERGY BOARD

Before many tribunals, when an intervener meets the applicable standing test, they may also be entitled to some form of participant funding. This funding may be payable either by the project proponent or through the tribunal's funding program. For example, the NEB now has a Participant Funding Program, established under section 16.3 of the *NEB Act*.[435] The NEB recently granted funding through this new Participant Funding Program to eligible participants for the Vantage Pipeline Project and the Bakken Pipeline Project.

1. *NATIONAL ENERGY BOARD PARTICIPANT FUNDING PROGRAM, FUNDING REVIEW COMMITTEE'S REPORT: ALLOCATION OF FUNDS FOR PARTICIPATION IN THE PUBLIC HEARING FOR THE VANTAGE PIPELINE PROJECT*[436]

a. Application

Following the NEB's announcement that $175,000 would be available for participant funding for the Vantage Pipeline Project, the NEB received six applications totalling $332,988, all from Aboriginal communities indicating that they had traditional territory in the vicinity of the proposed pipeline route.

433 *Ibid* at para 30.
434 *Ibid* at para 37.
435 Section 16.3 is a relatively new addition to the *NEB Act*. The *NEB Act* was amended to include section 16.3 by the *Jobs and Economic Growth Act*, SC 2010, c 12, s 2149. The *Jobs and Economic Growth Act* was given Royal Assent on 12 July 2010. Under the NEB's Participant Funding Program, funding may be provided for the following activities:
- … coordinating the collaboration of interested parties to the hearing;
- Review and provision of comments on the draft List of Issues and scope of the environmental assessment to be considered during the hearing;
- Review of the application and [proponent's Environmental Impact Statement]; and
- Preparation for and participation in hearings.

Eligible expenses include professional and legal fees, travel, collection of information, costs of booking a meeting space, and other costs necessary for a proposed activity. NEB, "Allocation of Funds for Participation in the Public Hearing for the Bakken Pipeline Project," online: NEB <https://www.neb.gc.ca/clf-nsi/rthnb/pblcprtcptn/prtcpntfndngprgrm/llctnfnd_bkknpplnprjct-eng.htm>.
436 (21 January 2011) [Vantage Pipeline].

b. Background

To receive NEB participant funding, would-be recipients must demonstrate that they meet at least one of the following criteria: (1) a direct, local interest in the project, such as living or owning property near the project area; (2) local community insights or Aboriginal traditional knowledge related to the proposed project; (3) an interest in potential project impacts on treaty or settlement lands, traditional territories, or related claims and rights; (4) plan to provide expert information respecting the mandate and decisions of the NEB on the proposed project.[437]

The NEB's Funding Review Committee (FRC) will also consider factors such as the nature of the applicant's interest, the potential impact of the project on that interest, and "anticipated usefulness" of the applicant's proposed contribution to the regulatory process.[438]

c. Key Findings

The FRC evaluated the applications with a focus on: (1) compliance with the *Guide to the National Energy Board Participant Funding Program Under the* National Energy Board Act;[439] and (2) the potential to contribute unique information to the hearing with respect to traditional knowledge, potential environmental effects, and effects on Aboriginal and treaty rights.[440]

The FRC found that detailed information regarding (1) how the funds would be applied as contributions to the NEB hearing process, (2) "how the objectives of participation would be delivered,"[441] and (c) "[e]vidence of collaboration between like-minded participants," was particularly helpful.[442]

d. Decision

The FRC recommended funding for all six applicants, though at levels "significantly below requested amounts."[443] It noted that the applicants would each have to revise their workplans to accommodate available funding and could try to find opportunities to collaborate.[444]

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437 *Ibid* at 1.
438 *Ibid* at 3.
439 NEB, *Guide to the National Energy Board Participant Funding Program Under the* National Energy Board Act (Ottawa: National Energy Board, 2010).
440 Vantage Pipeline, *supra* note 436 at 4.
441 *Ibid* at 4.
442 *Ibid* at 5.
443 *Ibid* at 4.
444 *Ibid*.

2. *NATIONAL ENERGY BOARD PARTICIPANT FUNDING PROGRAM, FUNDING REVIEW COMMITTEE'S REPORT, ALLOCATION OF FUNDS FOR PARTICIPATION IN THE PUBLIC HEARING FOR THE BAKKEN PIPELINE PROJECT*[445]

a. Application

In response to its announcement that $75,000 would be available for participant funding for the Bakken Pipeline Project, the NEB received 12 applications totalling $614,492. The majority of these were "from Aboriginal communities indicating that they had traditional territory in the vicinity of the proposed pipeline route."[446]

b. Key Findings

The FRC applied the same criteria as those set out for Vantage Pipeline, above. It found that the various First Nation and non-governmental organizations that had applied were "well positioned" to coordinate amongst themselves and reduce duplication before the NEB.[447]

c. Decision

The FRC recommended funding for eight of the 12 applicants, and again noted the likelihood of opportunities for increased cooperation and collaboration among the applicants.

VIII. DEVELOPMENTS IN LEGISLATION, POLICY, AND GUIDELINES

A. AMENDMENTS TO THE *ALBERTA LAND STEWARDSHIP ACT*

On 1 March 2011, Bill 10, the *Alberta Land Stewardship Amendment Act* (Bill 10),[448] passed through first reading, and was later given Royal Assent on 13 May 2011. Bill 10 attempts to add clarity to the government's position on certain issues arising from the *Alberta Land Stewardship Act*,[449] and in the words of the government "addresses landowner concerns" that have arisen in relation to the *ALSA*.[450]

1. BACKGROUND

The *ALSA*, which was passed in October 2009, divides the province into seven land use regions. Under the *ALSA*, the creation of a regional land use plan is mandatory for the seven regions, as well as for both the Calgary and Edmonton areas. Once a regional plan is

445 (21 March 2011).
446 *Ibid* at 3.
447 *Ibid* at 4.
448 Bill 10, *Alberta Land Stewardship Amendment Act, 2011*, 4th Sess, 27th Leg, Alberta, 2011 (assented to 13 May 2011), SA 2011, c 9 [Bill 10].
449 SA 2009, c A-26.8 [*ALSA*].
450 Government of Alberta, News Release, "Amended land-use Act addresses landowner concerns" (1 March 2011), online: Government of Alberta <http://alberta.ca/acn/201103/29986730A705-A560-E427-38630BBB98E25D78.html>.

established, development decisions within the region must be made in accordance with that plan.

Since its enactment, a number of public concerns have been raised about the *ALSA*, including: (1) lack of stakeholder consultation in the creation of, or amendments to, regional plans; (2) extinguishment of landowners' and mineral title holders' property rights without due compensation; (3) usurpment of municipalities' abilities to make local land-use planning decisions, and (4) limited access to the courts to appeal decisions made under *ALSA*.[451]

2. AMENDMENTS TO THE *ALSA*

Key amendments to the *ALSA* set out in Bill 10:

(i) Add to the Purposes section that "the Government *must respect the property and other rights of individuals and must not infringe on those rights except with due process of law* and to the extent necessary for the overall greater public interest";[452]

(ii) Clarify that "instruments" (particularly certificates of title) issued under certain acts, such as the *Land Titles Act*,[453] are not included in the definition of "statutory consent" (and thus not subject to extinguishment under section 11 of the *ALSA* as many have feared);[454]

(iii) Require the Minister, before making or amending a regional land-use plan, to ensure that appropriate public consultation has been carried out;[455]

(iv) Remove section 9(2)(f), which currently allows a regional plan to make law "about matters in respect of which a local government body may enact a regulatory instrument";[456]

(v) Soften the language in the controversial section 11 by changing "extinguish" to "rescind" and adding a requirement that before rescinding or otherwise affecting an existing statutory consent, the Minister must not only notify the statutory consent holder and allow them to suggest alternatives, but must also give them notice of any proposed compensation and the mechanism by which compensation will be determined;[457]

(vi) Clarify that a regional plan cannot amend or rescind municipal development approvals where the development is underway or completed at the time the regional plan comes into force;[458]

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451 See Government of Alberta, News Release, "Greater clarity under amended land-use Act. Legislation addresses concerns of landowners, other Albertans" (11 May 2011), online: Government of Alberta <http://www.alberta.ca/acn/201105/30383E023A549-F473-0F36-D5675794E6CC733C.html>.

452 Bill 10, *supra* note 448, s 2 [emphasis added]

453 RSA 2000, c L-4.

454 Bill 10, *supra* note 448, s 3(c).

455 *Ibid*, s 5.

456 *ALSA*, *supra* note 449, s 9(2)(f) as repealed by Bill 10, *ibid*, s 7.

457 Bill 10, *ibid*, ss 8(a), (b).

458 *Ibid*, s 8(c).

(vii) Allow title holders to apply for a variance of any restriction or requirement regarding a land area as it affects the title holder. The Minister may grant a variance despite the regional plan, with consideration of the public interest, the intent of the regional plan and any "unreasonable hardship" to the applicant;[459] and

(viii) Add an express right to compensation in the event that a registered owner of private land or freehold minerals, by reason of the ALSA or a regional plan, experiences diminution of a property right, title or interest giving rise to compensation. This right is subject to determination by land compensation boards or the Court of Queen's Bench.[460]

B. THE *CARBON CAPTURE AND STORAGE STATUTES AMENDMENT ACT, 2010*[461]

On 2 December 2010, Bill 24 came into force. Bill 24 establishes a legislative and regulatory framework for carbon capture and storage (CCS) in Alberta by amending the *Mines and Minerals Act*,[462] the *ERCA*, the *Public Lands Act*,[463] the *SRA*, and the *OGCA*. Key changes include: (1) a declaration that the Crown owns all of the pore space in the province; the creation of a scheme to dispense exploration and injection rights; (2) the transfer of long-term liability for CCS projects to the Crown; and (3) the creation of a fund to manage certain costs, including monitoring the behaviour of captured CO_2 post-closure and costs associated with orphan facilities.

1. PORE SPACE OWNERSHIP

The issue of pore space ownership is critical to the government's ability to dispense CCS exploration and disposal rights. The amendments to the *MMA* make it clear that all pore space is the property of the Crown.[464] Ownership is not affected by any grant from the Crown of land or minerals, including original grants, out of which the pore space is deemed excluded, or any extraction of minerals or water from the subsurface. No expropriation occurs as a result of this declaration of pore space ownership.[465] With these changes, the Government of Alberta has now given itself clear authority to dispense the right to access pore spaces for CCS.

2. EXPLORATION AND DISPOSAL RIGHTS

Bill 24 amended the *MMA* to allow the Minister of Energy to enter into agreements for the use of the pore space. The new Part 9 sets out two types of agreements. Exploration rights stem from agreements under section 115 of the *MMA*, in which the Minister can grant rights to drill wells to evaluate a subsurface reservoir. Disposal rights stem from agreements under section 116 in which the Minister may grant a person the right to inject captured CO_2 into

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459 *Ibid*, s 12.
460 *Ibid*, s 14.
461 Bill 24, *Carbon Capture and Storage Statutes Amendment Act, 2010*, 3rd Sess, 27th Leg, Alberta, 2010 (assented to 2 December 2010), SA 2010, c14 [Bill 24].
462 RSA 2000, c M-17 [*MMA*].
463 RSA 2000, c P-40.
464 Bill 24, *supra* note 461, s 2(6).
465 *MMA*, *supra* note 462, s 15.1(4).

a subsurface reservoir for sequestration. These agreements cannot be transferred without the written consent of the Minister.[466]

Both exploration and disposal rights holders will have to submit monitoring, measurement, and verification plans for approval, and provide reports regarding their compliance with those plans. At the injection stage, project proponents must also obtain a well licence from the ERCB under the *OGCA*, and submit a site closure plan for approval.[467]

Amendments to the *OGCA* prohibit the ERCB from approving the injection of captured CO_2 until it is satisfied that the injection will not interfere with the recovery or conservation of oil or gas, or an existing use of the underground formation for the storage of oil or gas.[468]

3. LONG-TERM LIABILITY

Long-term liability for CCS projects in Alberta will now vest in the Crown. When a CCS project is complete, the lessee must apply to the Minister for a closure certificate, which the Minister may issue if satisfied that the lessee has: (1) monitored all wells and facilities, performed all closure activities, and abandoned all wells and facilities in accordance with legislation; (2) complied with the *EPEA* reclamation requirements; and (3) the captured CO_2 "is behaving in a stable and predictable manner, with no significant risk of future leakage."[469]

On the issuance of a closure certificate the Crown becomes the owner of the captured CO_2, and assumes all of the lessee obligations: (1) as owner and licensee under the *OGCA*; (2) as the person responsible for the injected captured CO_2 under the *EPEA*; (3) as the operator under the [*EPEA*] in respect of the land within the location of project site; and (4) under the *SRA*.[470]

The Crown also agrees to indemnify the lessee against liability for damages in an action in tort if the liability is attributable to an act or omission by the lessee in its exercise of rights under the CCS injection agreement, provided any conditions specified in the regulations are met. If the lessee ceases to exist prior to the issuing of a closure certificate, then the Crown may assume ownership of the injected CO_2 without having issued a closure certificate to the lessee.[471]

4. POST-CLOSURE STEWARDSHIP FUND

Bill 24 establishes the Post-closure Stewardship Fund (the Fund). The Fund is generated by payments from lessees, and administered by the Minister, and may be used for: (1) monitoring the behaviour of injected captured CO_2; (2) fulfilling any obligations assumed by

466 *Ibid*, s 118.
467 *Ibid*, ss 115(3), 116(2), 116(3).
468 *Ibid*, s 39(1.1). This provision suggests that any conflicts between mineral and CCS rights holders will be decided on a case-by-case basis, in accordance with the purposes of the *OGCA* and the *ERCA*, which now mandate the safe and efficient development of both energy resources and underground formations for the injection of substances. *OGCA*, *supra* note 90, s 4(b); *ERCA*, *supra* note 91, s 2(e).
469 *MMA*, *supra* note 462, s 120(3).
470 *Ibid*, s 121(1).
471 *Ibid*, ss 121(2)-(3).

the Crown as the owner, person responsible, and operator under the *MMA* and *EPEA*; (3) suspension, abandonment, and related reclamation or remediation costs for orphan facilities; and (4) covering costs incurred in pursuing reimbursement for orphan facility costs from the lessee responsible for paying them.[472]

C. AMENDMENTS TO THE *TRANSMISSION REGULATION*

In October 2010 the Government of Alberta adopted changes to the *T-Reg* under the *EUA*.[473]

Key changes in the updated *T-Reg* include the following: (1) the ability of the AESO to recommend to the Minister transmission facilities that in its opinion merit designation under section 41.1(1) of the *EUA* as "critical transmission infrastructure";[474] (2) the requirement for the AESO to create a competitive process that allows any qualified person, as determined by the AESO, who is eligible to apply for the construction or operation, or both, of certain critical transmission facilities and intertie facilities, to submit a proposal in respect to those facilities, including a financial bid;[475] (3) express oversight by the Transmission Facility Cost Monitoring Committee established by the Minister pursuant to section 7 of the *Government Organization Act*[476] over the preparation of cost estimates, project scope documents, and schedule documents;[477] and (4) clarifying that the requirement in section 16(1) of the *T-Reg* to restore the existing interties does not give existing interties preference to any allocation of available transfer capability.[478]

D. NEW ALBERTA SUSTAINABLE RESOURCES DEVELOPMENT ENHANCED APPROVAL PROCESS

Effective 1 September 2010, ASRD instituted the new Enhanced Approval Process (EAP).[479] The EAP is a new approval process for all upstream oil and gas activities (excluding in-situ and oil sand mines operations) for the following four disposition types: (1) mineral surface leases; (2) licences of occupation; (3) pipeline agreements; and (4) pipeline installation leases.

Downstream oil and gas activities, other than pipelines, and all other land activities, including in-situ oil sands production, and oil sands mines, will continue to use the existing Environmental Field Report process.

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472 *Ibid*, s 122(2).
473 Alta Reg 153/2010 [*T-Reg Amendment*].
474 *T-Reg*, *supra* note 343, s 10.1(1), as amended by *T-Reg Amendment*, *ibid*, s 9.
475 *T-Reg*, *ibid*, s 24.2, as amended by *T-Reg Amendment*, *ibid*, s 18.
476 RSA 2000, c G-10.
477 *T-Reg*, *supra* note 343, s 25.1, as re-enacted by *T-Reg Amendment*, *supra* note 473, s 20.
478 *T-Reg*, *ibid*, s 16(4), as amended by *T-Reg Amendment*, *ibid*, s 14.
479 For the full details on the EAP, refer to ASRD's site, ASRD, Enhanced Approval Process, online: ASRD <http://srd.alberta.ca/FormsOnlineServices/EnhancedApprovalProcess/Default.aspx>.

An important goal behind the EAP is to streamline application processing by providing a "more consistent, transparent, clear, and timely review process for government and industry."[480]

Key changes created by the EAP include the following: (1) all First Nation consultation must now be deemed complete by ASRD before an application for a disposition will be processed;[481] (2) upfront planning tools are now available to assist applicants with identifying landscape sensitivities, such as the Landscape Analysis Tool (LAT), a web-based geospatial planning tool; (3) applications can now be submitted and processed through standard or non-standard streams;[482] (4) ASRD has created the Integrated Standards and Guidelines (IS&G), which consolidates over 200 existing ASRD guidelines and documents into one set of provincial approval standards, operating conditions, best management guidelines and pre-application information for the upstream oil and gas industry. "For industry, the IS&G describes the minimal standards and conditions that must be met. For [A]SRD, the IS&G will contribute to compliance assurance and identify best practices for protecting Alberta's public land";[483] and (5) "current [A]SRD compliance programs will be used for EAP dispositions."[484]

E. OFFSHORE HELICOPTER SAFETY INQUIRY, OCTOBER 2010

1. IMPLEMENTATION OF THE C-NLOPB OFFSHORE HELICOPTER SAFETY INQUIRY

On 8 April 2009 the C-NLOPB began its Offshore Helicopter Safety Inquiry (the Inquiry) in response to the accident on 12 March 2009 which caused the deaths of 17 people. The Inquiry proceeded throughout 2009 and 2010, and on 17 November 2010 the Offshore Helicopter Safety Inquiry Report, Phase I (the Report) was provided to the C-NLOPB and immediately released to the public.[485] The Report set out 29 recommendations, including a dedicated first-response helicopter, the establishment of performance-based goals for first

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480 "How does the EAP streamline disposition application?" in ASRD, "EAP FAQ" (29 April 2011), online: ASRD<http://www.srd.alberta.ca/FormsOnlineServices/EnhancedApprovalProcess/EAPFAQ. aspx>.

481 "Is it possible to file a non-standard application based on outstanding concerns and/or issues with First Nation consultation?," in "EAP FAQ," *ibid.*

482 "How does the EAP differ from the existing process?" in "EAP FAQ," *ibid.*

483 "What are the Integrated Standards and Guidelines (IS&G)? in "EAP FAQ," *ibid*. The LAT and IS&G will work together to:

> incorporate specific information from a shapefile used by clients to plan their activities in a spatial context. The proposed disposition type, purpose type, and location included in a shapefile is used by the tool to generage a LAT report. The LAT report identifies the applicable provincial and sensitivity section approval standards and operating conditions that a proponent will be held accountable to by SRD upon issuance of a short-term disposition. For example, if a proposed disposition falls within a fescue grassland sub-region, the LAT report will direct users to the specific approval standards and operating conditions that must be complied with if a short-term disposition has been issued by SRD.

"How do the IS&G and LAT work together?" in "EAP FAQ," *ibid*.

484 "Does the EAP have a compliance assurance function?," in "EAP FAQ," *ibid*.

485 Phase II of the Inquiry was scheduled to follow the release of the Transportation Safety Board's report on the cause of the crash. C-NLOPB, *Offshore Helicopter Safety Inquiry*, vol 1 (St. John's" C-NLOPB, 2010), online: C-NLOPB <http://www.cnlopb.nl.ca/ohsi_ information.shtml> [*Safety Inquiry*]. This was completed as of 9 February 2011 C-NLOPB, News Release, "C-NLOPB Says it will Review the TSB Report and Decide Next Steps," online: C-NLOPB <http://www.cnlopb.nl.ca/news/nr20110209. shtml>).

response, various planning and in-flight protocols, and training of oil workers on helicopter operations and safety.[486]

Following receipt of the Report, the C-NLOPB proceeded to develop an implementation plan. On 13 December 2010, the C-NLOPB announced its first steps towards an implementation strategy for the Report, accepting 27 of the 29 recommendations in full.[487]

The recommendation of a ban on night flights was accepted in principle, with the exception of medical emergencies. The recommendation regarding changes to C-NLOPB's mandate and structure was referred to the appropriate governmental authorities for consideration.

486 *Safety Inquiry*, *ibid* at 291-303.

487 C-NLOPB, News Release, "Implementation Strategy for the Offshore Helicopter Safety Inquiry Phase I Report Recommendations" (13 December 2010), online: C-NLOPB <http://www.cnlopb.nl.ca/news/nr20101213.shtml>.