RECENT REGULATORY AND LEGISLATIVE DEVELOPMENTS OF INTEREST TO OIL AND GAS LAWYERS 2006-2007

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The purpose of this article is to highlight and discuss regulatory and legislative developments during the period of May 2006 through April 2007 that are of particular interest to oil and gas lawyers. The article primarily examines decisions of the National Energy Board and the Alberta Energy and Utilities Board as well as related jurisprudence. Additionally, the article details certain key policy and legislative developments affecting the National Energy Board and the Alberta Energy and Utilities Board, and touches on notable regulatory, policy, and legislative developments in other jurisdictions.

Le but de cet article consiste à souligner et discuter les développements réglementaires et législatifs ayant eu lieu entre mai 2006 et avril 2007, et intéresse particulièrement les avocats qui travaillent dans le secteur pétrolier et gazier. L'article examine essentiellement les décisions de l'Office national de l'énergie et du Alberta Energy and Utilities Board ainsi que la jurisprudence connexe. De plus, l'article décrit en détail certains développements législatifs et politiques importants touchant l'Office national de l'énergie et le Alberta Energy and Utilities Board, et aborde les développements notoires en termes de réglementation, de politique et de législations dans d'autres ressorts.

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I. INTRODUCTION

This article includes a review of Canadian energy regulatory decisions and related jurisprudence and developments during the period of May 2006 to April 2007. This article also highlights important legislative and policy developments during the same period relating to energy development and regulation. Although decisions and policies of both the National

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Energy Board and the Alberta Energy and Utilities Board are the primary focus, this article also touches on decisions and policies of the Alberta Surface Rights Board, the British Columbia Utilities Commission, the Ontario Energy Board, the Canada-Newfoundland and Labrador Offshore Petroleum Board, and the Canada-Nova Scotia Offshore Petroleum Board.[1]

II. REGULATORY DECISIONS AND RELATED JURISPRUDENCE

A. NATIONAL ENERGY BOARD

The National Energy Board (NEB) was established in 1959, and enabled under the *National Energy Board Act*[2] and has delegated authority under other federal acts.[3] The NEB regulates various aspects of the energy industry within Canada, including: construction, operation, and safety of interprovincial and international pipelines and power lines; pipeline traffic, tolls, and tariffs; the export and import of natural gas, oil, and electricity; and frontier oil and gas.[4] The NEB may review and vary its decisions and any appeal of a NEB decision lies with the Federal Court of Appeal.[5] NEB decisions and Federal Court jurisprudence of significance to oil and gas lawyers during the May 2006 to April 2007 period are discussed below.

1. DECISION RH-1-2006: TRANSCANADA PIPELINES LIMITED SHORT NOTICE SERVICES[6]

On 23 November 2006, the NEB approved an application by TransCanada PipeLines Limited (TCPL) to implement two new services on the TCPL mainline pipeline system: the firm transportation-short notice (FT-SN) and the short notice balancing (SNB) service (collectively the Short Notice Services). TCPL sought approval of the Short Notice Services to serve anticipated growth in gas-fired generation in Ontario in a way that accommodated significant fluctuations in gas consumption from day-to-day and within the day, due to five-minute dispatch notifications issued by the Ontario Independent Electric System Operator. The NEB approved the FT-SN service and toll design, but in the case of SNB, only the service attributes were approved; the proposed tolling methodology was rejected.

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1 The review of decisions, jurisprudence, and legislative and policy changes is not exhaustive; instead, this article includes significant energy regulatory developments that would be of interest to the majority of oil and gas lawyers.

2 R.S.C. 1985, c. N-7 [*NEB Act*].

3 Including, but not limited to: *Canada Oil and Gas Operations Act*, R.S.C. 1985, c. O-7 [*COGO Act*]; *Canada Petroleum Resources Act*, R.S.C. 1985 (2nd Supp.), c. 36; *Northern Pipeline Act*, R.S.C. 1985, c. N-26.

4 *NEB Act*, *supra* note 2. See also the NEB website, online: NEB <http://www.neb-one.gc.ca/clf-nsi/rcmmn/hm-eng.html>.

5 *NEB Act*, *ibid.*, ss. 21-22.

6 NEB, *In the Matter of TransCanada Pipelines Limited, Application for Approval of Short Notice Services and Related Tolls*, Reasons for Decision, RH-1-2006 (November 2006).

a. FT-SN Service

Unlike FT service, which only permits nominations 4 times daily and assures capacity only for the first nomination window, FT-SN service would permit nominations every 15 minutes throughout the gas day and assure contract holders their nominated capacity. Separate delivery areas, meter stations, and flow control were proposed to distinguish between FT-SN and other volumes, and to safeguard the system. The FT-SN toll was set at a 10 percent premium over the FT toll (that is to say 110% of FT service toll), which TCPL estimated to be the opportunity cost of revenue that may be lost. As FT-SN capacity would be guaranteed at each 15-minute nomination window, any unused FT-SN service capacity could not be made available for discretionary services. TCPL also proposed that all FT-SN service tolls be credited to non-discretionary miscellaneous revenue, thereby providing a fixed cost contribution.

The NEB accepted that separate delivery areas, meter stations, and flow control valves were required to safeguard TCPL's system from unpredictable, fluctuating consumption associated with offering FT-SN service to the new power market. In doing so, however, the NEB encouraged TCPL to consider future changes whereby multiple services could be delivered at FT-SN delivery points. The NEB also accepted the opportunity cost tolling methodology but expressed concern that the methodology did not consider all costs associated with offering the FT-SN service. As a result the NEB directed TCPL to conduct a yearly re-calculation of the opportunity cost for the foregone discretionary revenues and to consult with stakeholders to ensure that all costs of providing FT-SN service are included in the FT-SN premium. Additionally, the NEB concluded that since FT-SN was a firm service it should be treated the same as FT service, with contract demand for FT-SN service being included in calculation of the allocation units for toll design purposes. Only the premium, due to its arbitrary nature, should be credited to non-discretionary miscellaneous revenue. Finally, it is interesting to note that the NEB rejected intervener arguments relating to value-based tolling, indicating that value-based tolling methodologies are more appropriate where a clear comparison of value between services can be made.

b. SNB Service

SNB was proposed to facilitate the effective operation of FT-SN service (an FT-SN contract was a prerequisite). Using TCPL's mainline compression and linepack, FT-SN shippers would be provided with sufficient load balancing flexibility to permit effective 15-minute nominations even where interconnecting pipelines did not offer the same number as, or align nomination windows with, FT-SN service. TCPL proposed an incremental toll with two components: an annual owning and operating expense including fixed operating, maintenance, depreciation, return and tax expenses for facilities deemed, by way of models, to be used to provide SNB service for each service contract; and a general administrative expense.

The NEB agreed with TCPL that SNB is a balancing rather than a transportation service and approved the attributes of the service, but rejected the toll design as seriously flawed. Shippers located very close to each other but who do not receive their Short Notice Services through the same meter could be charged significantly different tolls. Additionally, TCPL's requested discretion to determine which facilities would be required to provide the service was not transparent and could be viewed as arbitrary. Finally, the SNB services would be provided using TCPL's integrated system and similar terms and conditions should apply to shippers using that system. As a result, the NEB rejected TCPL's service tolling methodology and directed TCPL to develop and seek approval for an alternative methodology using a cost-based averaging approach based on geographic area. Revenue from the new toll design is to be credited to non-discretionary miscellaneous revenue.

2. DECISION MH-1-2006: TRANSFER OF A PORTION OF TCPL'S MAINLINE TO TRANSCANADA KEYSTONE PIPELINE GP LTD.[7]

On 5 February 2007, the NEB approved a joint application by TCPL and TransCanada Keystone Pipeline GP Ltd. (Keystone), a wholly owned subsidiary of TCPL, under s. 74 of the *NEB Act* to transfer, by way of sale and purchase at net book value, and remove from rate base a portion of TCPL's mainline gas transmission system[8] (the TCPL Facilities) from TCPL to Keystone. Keystone proposed a new export oil pipeline from Hardisty, Alberta to Wood River and Patoka, Illinois (the Keystone Pipeline) that would include the transfer and conversion from gas to oil service of the TCPL Facilities combined with construction of new oil pipeline facilities.

Pursuant to ss. 74 and 59 of the *NEB Act*, the MH-1-2006 proceeding addressed the transfer and removal from rate base of the TCPL Facilities, while a subsequent facilities application by Keystone would address the need for the Keystone Pipeline.[9] TCPL and Keystone argued that although the TCPL Facilities were used and useful, they were no longer needed for gas service and their "best use" would be in providing much needed oil transportation capacity.

The NEB first considered whether the applicable regulatory standard for determining whether to grant the application was that of "public interest," as submitted by TCPL and Keystone, or "no harm to customers" as submitted by interveners.[10] Relying heavily on the Supreme Court of Canada's decision in *ATCO Gas & Pipelines Ltd. v. Alberta (Energy & Utilities Board),*[11] the interveners argued that failure to adopt the no-harm test would be an error in law. TCPL and Keystone argued that ATCO had no application to the NEB's determination and that, properly interpreted, the *NEB Act* established the standard of the Canadian public interest, which went beyond the interests of just the gas shippers.

The NEB concluded that the Supreme Court's decision in *ATCO* was not applicable to determining the regulatory standard to be applied to the transfer of the TCPL Facilities as the

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7 NEB, *In the Matter of TransCanada PipeLines Limited and TransCanada Keystone Pipeline GP Ltd.*, Reasons for Decision, MH-1-2006 (February 2007) [Decision MH-1-2006].

8 Line 100-1 between Burstall, Saskatchewan and Carman, Manitoba and associated facilities.

9 Keystone filed the facilities application for the Keystone Pipeline with the NEB on 12 December 2006. See also NEB, *Regarding TransCanada Keystone Pipeline GP Ltd. (Keystone), Keystone Pipeline Application*, Hearing Order, OH-1-2007 (29 January 2007).

10 *Supra* note 7 at 10-16. The primary intervener group was made up of BP Canada Energy Company, Coral Energy Canada Inc., Devon Canada Corporation, EnCana Corporation, Nexen Inc., and Shell Canada Limited.

11 2006 SCC 4, [2006] 1 S.C.R. 140 [*ATCO*].

Alberta Energy and Utilities Board (AEUB) decision under appeal by the Supreme Court in *ATCO* did not address the regulatory standard and the AEUB's choice to use the no-harm test was the subject of an earlier AEUB decision that was not under appeal. The NEB went on to consider the *NEB Act* and the applicable provisions under which the application had been made and concluded that although the provisions used similar language to those considered by the Supreme Court in *ATCO*, the principal function of the *NEB Act* was not as limiting as the Court found the *Gas Utilities Act*[12] to be in *ATCO*. Finally, the NEB concluded that its express public interest mandate under the *NEB Act* required it, in considering the application, to look beyond the adverse impact or harm that may result to gas pipeline shippers as a result of the transfer of the TCPL Facilities. To do otherwise would sterilize the broader public interest mandate granted to the NEB by Parliament and would cause it to commit an error in law. In spite of having found that the appropriate standard to be applied is that of "public interest," the NEB went on to say that even if the no-harm to shippers standard applied, it would have been met and the application approved.

Having considered evidence in relation to energy supply (gas and oil), markets and pipelines, and evidence in relation to potential impact of the transfer of the TCPL Facilities including: gas transmission capacity, costs to gas shippers, and the impact of the transfer on TCPL's mainline operations, the NEB concluded that the transfer of the TCPL Facilities and the proposed rate base treatment was in the public interest. The NEB also concluded that it would not be in the public interest to order the continued use of the TCPL Facilities in gas service when it has been demonstrated that they are not necessary.

Of additional interest are the NEB's comments on an applicant's right to structure its case as it sees fit. Interveners sought an adjournment of the proceeding until applications for all the approvals required for the entire Keystone Pipeline (for instance, the transfer of the TCPL Facilities as well as approvals for the required new facilities) were before the NEB.[13] The NEB responded that it is acceptable for applicants to frame an application as they wish for their own business reasons, even where it results in some overlap of proceedings, unless on the facts of the specific case there are cogent reasons not to do so (for example, abuse of process, serious waste of time or resources for the NEB, project splitting, or attempts to avoid jurisdiction or process).

3. DECISION RH-2-94: MULTI-PIPELINE COST OF CAPITAL DECISION - RATE OF RETURN ON COMMON EQUITY FOR 2007[14]

In keeping with the NEB's Multi-Pipeline Cost of Capital Decision in which the NEB established a return on equity (ROE) formula to be applied to certain pipelines under its jurisdiction, the NEB approved an ROE for 2007 of 8.46 percent. Consistent with the NEB's formula, this ROE was premised on a forecast 10-year Government of Canada bond yield of

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

13 Decision MH-1-2006, *supra* note 7 at 7, 71-79.

14 NEB, *In the Matter of TransCanada PipeLines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd., Trans Québec & Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd., Trans-Northern Pipeline Inc.*, Reasons for Decision, RH-2-94 (March 1995); NEB, Letter, "Rate of Return on Common Equity (ROE) for 2007" (23 November 2006).

4.15 percent and an estimated 30-year forecast Government of Canada bond yield of 4.22 percent. This 2007 ROE is a 42 basis point reduction from the NEB's 2006 ROE of 8.88 percent.

4. DECISION OH-1-2006: TERASEN PIPELINES (TRANS MOUNTAIN) INC. TMX - ANCHOR LOOP PROJECT[15]

In October 2006, the NEB issued Decision OH-1-2006, approving the Terasen Pipelines (Trans Mountain) Inc. (Trans Mountain)[16] application pursuant to s. 52 of the *NEB Act* for a certificate of public convenience and necessity for the TMX - Anchor Loop Project, which involved twinning the Trans Mountain pipeline system through Jasper National Park and Mount Robson Provincial Park.[17]

The two most noteworthy aspects of the OH-1-2006 Decision are the NEB's approach to a preliminary motion by an Aboriginal group[18] and comments concerning the public consultation process.

a. Consultation

That an oral hearing to consider pipeline construction through a National and a Provincial park and a World Heritage site lasted less than three days, most of which were consumed by a procedural motion, and attracted only one objecting intervener,[19] the Simpcw First Nation (SFN), was a testament to Trans Mountain's public involvement program. To demonstrate the depth and breadth of Trans Mountain's public involvement program, the NEB reiterated its more important aspects as described in the evidence, discussed the aspects that the NEB found compelling and characterized the approach as "exemplary."[20]

b. Procedural Motion

On 3 August 2006, three days before the NEB's oral public hearing was to commence, the SFN filed a notice of motion based mainly on procedural fairness and lack of Crown consultation, requesting, among other things, that the NEB delay its hearing process by six months. The motion followed on the heels of a 31 July 2006 letter to the NEB and other responsible authorities demanding that all environmental assessment proceedings and undertakings immediately cease and that the environmental assessment under the *Canadian Environmental Assessment Act*[21] proceed by way of panel review.

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15 NEB, *In the Matter of Terasen Pipelines (Trans Mountain) Inc.*, Reasons for Decision, OH-1-2006 (October 2006) [Decision OH-1-2006].

16 As a result of a corporate reorganization, the Trans Mountain pipeline is now owned by Trans Mountain Pipeline LP, the limited partner of which is Trans Mountain Pipeline Inc.

17 The TMX - Anchor Loop Project consists of a pipeline loop and associated facilities which generally parallel the existing Trans Mountain right-of-way through Jasper National Park and Mount Robson Provincial Park. The Project provides an incremental capacity of approximately 40,000 barrels per day.

18 See *supra* note 15 at App. II, which contains the NEB Ruling on the Motion and *CEAA* Process Complaint Letter by the SFN (24 August 2006).

19 There were two letters of comment opposing the project, but neither party appeared at the hearing.

20 *Supra* note 15 at 20.

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

The NEB determined that there were no procedural fairness or consultation shortcomings, dismissed the SFN motion and *CEAA* complaint and, in the process, sent two very clear messages of more general application. First, a party bringing a motion bears a burden of proof that can only be discharged by sworn or affirmed evidence, either in an affidavit in support of the motion or otherwise on the record and adopted (or to be adopted later) by a witness. Without such evidence, a motion must fail. Second, all parties, including the applicant, have a right to procedural fairness, which includes bringing forward on a timely basis any motion that may affect others. In concluding its ruling, the NEB expressed its view that:

> [P]arties to a regulatory proceeding, including First Nations, are under an obligation to raise issues in a timely way in order to allow the applicant to respond. Furthermore, although the SFN has a right to expect procedural fairness, so do other parties. As such, the Board has to weigh the lateness of this submission against the rights of other parties and, in particular, the right of the applicant to have its application heard in a timely manner.[22]

5. LETTER DECISION: TERASEN PIPELINES (TRANS MOUNTAIN) INC. TARIFF REVISIONS — WESTRIDGE DOCK ALLOCATION PROCEDURE[23]

On 8 February 2006, Kinder Morgan Canada Inc. (KMCI), the operator of the Trans Mountain system, filed two new tariffs, which, in part, collectively amended the capacity nomination dates for the Westridge Dock (a marine loading terminal connected to the Trans Mountain pipeline) and introduced a change to the Dock capacity allocation procedure.

At the time, capacity on the Trans Mountain pipeline was initially allocated to three destinations — domestic, export, and Westridge Dock. Allocation to the domestic and export destinations was on a percentage of capacity basis: the Dock was allocated a fixed 3,600 m^3/day (two cargoes based on the size of tankers taking delivery at the dock).[24]

Because shippers nominated Dock capacity in tanker-size lots, over-nominations could not be apportioned as they were for the domestic and export destinations. Prior to the February 2006 toll application, the Westridge Dock capacity was allocated on an all or nothing basis using a lottery. Because capacity nominations for all destinations, including the Dock, were due on the same day, shippers who were unsuccessful in the lottery were caught nominated with volumes and upstream pipeline capacity that ultimately lacked a destination. Trans Mountain initially amended its tariffs to allow two-day advance nominations for Westridge Dock delivery which would permit the lottery to be held in

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22 Decision OH-1-2006, *supra* note 15 at 60.

23 NEB, *In the Matter of Trans Mountain Pipeline Inc. (Formerly Terasen Pipelines (Trans Mountain) Inc.), Capacity Allocation Procedures,* Reasons for Decision (March 2006 - August 2007). Note that Trans Mountain Pipeline Inc. submitted a number of applications to the NEB regarding "significant and controversial changes to the capacity allocation procedures on the pipeline system" (at Introduction). The Board released decisions on these applications on 15 March 2006, 12 April 2006, 20 July 2006, and 16 August 2007. These decisions have since been amalgamated into a single document.

24 On 13 March 2007, an application was filed with the NEB, which, if approved, would among other things, increase the capacity allocated to the Dock by 2,464 m^3/d to 6,070 m^3/d and divide the Dock capacity between tankers and barges by reserving sufficient capacity for a minimum of one barge per month.

advance of nominations for the domestic and export destinations and permit those who lost the lottery to subsequently nominate for other destinations. However, this system did not permit Trans Mountain to verify requisite volumes and upstream pipeline capacity. The result was that in the first month of its operation, the two-day advance nomination resulted in 37 cargoes being nominated and in Trans Mountain's view, not being able to verify actual volumes or upstream pipeline capacity resulted in a secondary market for dock capacity whereby the "winner" of the lottery could subsequently assign the capacity to another.

To eliminate the secondary market, Trans Mountain kept the two-day advance nomination date but replaced the lottery with a bidding system whereby shippers nominating would assign a premium, on a cents per cubic metre basis, that they would be willing to pay to acquire capacity on the dock. Trans Mountain would then rank and allocate Westridge Dock capacity on the basis of the highest premiums. In months where there was no need for apportionment on the Westridge Dock, the bid premium would not be collected.

The NEB first concluded that the lottery system clearly resulted in circumstances that could allow a secondary market to influence the allocation of scarce dock capacity and gaming of the allocation system. The NEB distinguished between the use of secondary markets for unused pipeline capacity which maximize pipeline utilization and secondary markets for dock capacity which do not. The NEB also concluded that the bid premium was efficient both from an economic and allocative efficiency perspective since the premium revenue would benefit all shippers, not just those using the Dock.

In approving the new tariffs for a three-month trial period which was subsequently extended to the first quarter 2007, the NEB concluded that the bid premium did not contravene the common carrier obligations of Trans Mountain.[25] The NEB further determined that the non-rateable nature of marine deliveries required that they be treated differently from land destinations and consequently, the Westridge Dock bidding mechanism was not unjustly discriminatory as between land- and dock-based nominations. Further, the NEB found that since all shippers have an opportunity to bid, under the same circumstances, for capacity on the dock, no unjust discrimination occurred as between the shippers to the dock. Finally, the NEB found that the allocation, during apportionment, of non-rateable capacity to shippers who value it most while permitting any shipper to bid for such capacity were unique circumstances and conditions surrounding the traffic across the Westridge Dock. Based on this characterization, the NEB concluded that the bid premium was primarily a mechanism for allocating capacity and impliedly "not primarily a tolling methodology"[26] which resulted in no unjust discrimination in tolls.

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[25] *Supra* note 23 at 12.

[26] Subsequently expressly stated by the NEB, *ibid.* at 40.

6. UPDATE ON NEB HEARING AND JOINT REVIEW PANEL HEARING FOR MACKENZIE GAS PROJECT

In October 2004, the Mackenzie Gas Project[27] application was filed with the NEB, seeking approval to transport gas from the Mackenzie Delta to Alberta.[28] The NEB hearing process is coordinated with a joint review panel (JRP) hearing in accordance with the Agreement for Coordination of the Regulatory Review of the Mackenzie Gas Project, dated 22 April 2004. The NEB hearings commenced on 25 January 2006, in Inuvik, Northwest Territories, and the JRP hearings started on 14 February 2006. The focus of the JRP process is on the environmental, socio-economic, and cultural issues of the Mackenzie Gas Project. The evidentiary portion of the NEB hearings concluded 14 December 2006, and the hearing was adjourned since argument must await the JRP environmental assessment report.

The Mackenzie Gas Project is comprised of (1) three anchor fields in the Mackenzie Delta, (2) the Mackenzie gathering system (MGS) for the transmission of gas and natural gas liquids (NGLs) from the anchor fields to an Inuvik-area facility (IAF) and for the further transmission of NGLs to Norman Wells, and (3) the Mackenzie Valley pipeline (MVP) for the transmission of gas from the IAF to northern Alberta. The Project Sponsors applied to the NEB under Part III of the *NEB Act* for a certificate of public convenience and necessity approving the construction and operation of the MVP, and under Part IV of the *NEB Act*, for approval of the proposed toll and tariff principles on the MVP. However, the Project Sponsors brought a separate application under para. 5(1)(b) of the *COGO Act*[29] for approval of construction and operation of the MGS.

a. Intervener Motions and Actions

On 7 April 2006, the Mackenzie Explorer Group[30] (MEG) brought a notice of motion seeking an order declaring that the proposed MGS and the MVP will be a single "pipeline" as defined in the *NEB Act*, and that both will be subject to NEB regulation regarding tolls and tariffs once they are built and placed in service. Members of the MEG are actively involved in the exploration and development of energy resources in and around the Beaufort-Mackenzie basin and expect to become shippers on the MGS and MVP in order to develop their resources.

The MEG argued that the legal and policy framework for transmission and related services should be the same for both the MGS and the MVP. The MEG proposed that the MGS and the MVP should be "designed, constructed and operated as a basin-opening, open-access

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27 Mackenzie Gas Project sponsors are Imperial Oil Resources Ventures Inc., Aboriginal Pipeline Group, ConocoPhillips Canada (North) Ltd., ExxonMobil Canada Properties, and Shell Canada Ltd. (Project Sponsors).

28 See NEB, *Regarding Various Applications to the National Energy Board (NEB) for the Mackenzie Gas Project,* Hearing Order, GH-1-2004 (24 November 2004) [Hearing Order GH-1-2004]. The Application by Imperial Oil Resources Ventures Limited (7 October 2004), pursuant to Parts III and IV of the *NEB Act* is referenced in Hearing Order GH-1-2004 at 2.

29 *Supra* note 3.

30 The Mackenzie Explorer Group consists of Anadarko Canada Corp., BP Canada Energy Co., Chevron Canada Ltd., Devon Canada Corp., EnCana Corp., and Nytis Exploration Co. Inc.

transmission system that is subject to financial regulation in the public interest."[31] The Project Sponsors maintained that the NEB has no regulatory oversight of services on the MGS and that it does not have the authority to adjudicate upon the justness and reasonableness of the fees and tariffs for the MGS.

In its letter of 10 July 2006,[32] the NEB reviewed the purpose and scheme of both the *COGO Act* and the *NEB Act* and determined that the *COGO Act* specifically addresses gas processing within the Northwest Territories, such as the IAF and NGL transportation that is entirely within the Northwest Territories. The NEB noted that a gas-processing facility can be a work connected to an NEB-regulated pipeline and regulated by the *NEB Act*, but that not every facility physically connected to a NEB-regulated pipeline is part of that pipeline. In denying the relief sought by MEG, the NEB concluded that "the demarcation between the *COGO Act* regulated facilities and the *NEB Act* regulated facilities is between the outlet of the IAF and the inlet of the MVP."[33]

The members of MEG, with the exception of EnCana Corporation, sought leave to appeal the NEB decision to the Federal Court of Appeal on the basis that if the shippers are not protected from the exercise of market power by the proponents of the Mackenzie Gas Project, the Canadian public interest will be detrimentally affected. The MEG's position is that the MGS and the MVP will be constructed and operated as a single undertaking that constitutes an interprovincial pipeline, subject to the protections afforded under Part IV of the *NEB Act*. The Court granted leave to appeal the NEB's decision on 19 September 2006.

The Dene Tha' First Nation (Dene Tha') filed an application for judicial review on 17 May 2005, claiming an ongoing failure of the Federal Ministers of Environment, Fisheries and Oceans, Indian and Northern Affairs, and Transport (the Ministers) to comply with their fiduciary and constitutional duties under s. 35 of the *Constitution Act, 1982*[34] to consult with the Dene Tha' and to accommodate their Aboriginal and treaty rights in relation to the environmental and regulatory review process for the Mackenzie Gas Project.

On 10 November 2006, the Federal Court ruled in favour of the Dene Tha' and granted its application for judicial review. In particular, the Federal Court held that "the Ministers breached their duty to consult the Dene Tha' in its conduct surrounding the creation of the regulatory and environmental review processes related to the [Mackenzie Gas Project] from as early as the first steps" — which included discussions and decisions regarding the design of the regulatory and environmental review processes — "and continued to breach that duty to the present time."[35] After acknowledging that "the issue of remedy in this case is not straightforward," the Federal Court (i) ordered a remedies hearing; (ii) stayed the JRP from considering any aspect of the Mackenzie Gas Project "which affects either the treaty lands

[31] Notice of Motion filed on behalf of Mackenzie Explorers Group, "Re: Hearing Order GH-1-2004; Mackenzie Gas Project; NEB File Nos. 3200-J205-1" (7 April 2006) at 3.6.

[32] NEB, Letter: "Mackenzie Gas Project (MGP) - Hearing Order GH-1-2004 - Ruling #16 Mackenzie Explorers Group (MEG) Notice of Motion No. 10" (10 July 2006) [NEB Letter (10 July 2006)].

[33] *Ibid.* at 13 [emphasis added].

[34] Being Schedule B to the *Canada Act 1982* (U.K.), 1982, c. 11.

[35] *Dene Tha' First Nation v. Canada (Minister of Environment)*, 2006 FC 1354, 25 C.E.L.R. (N.S.) (3d) 247 at para. 3.

of the Dene Tha' or the aboriginal rights claimed by the Dene Tha'"; and (iii) enjoined the JRP from issuing any report of its proceedings to the NEB.[36] The Ministers filed an appeal of the Federal Court's decision on 5 December 2006. On 30 January 2007, the Federal Court lifted the stay of the JRP hearings but ordered that "the JRP is restrained from issuing its final report until otherwise permitted by the Federal Court."[37]

In a separate proceeding on 30 November 2006, the Dene Tha' requested directions from the NEB in relation to its proposed notice of motion filed with the NEB on 30 November 2006. The proposed notice of motion asks the NEB GH-1-2004 panel to determine the question of the NEB's jurisdiction over the Nova Gas Transmission Ltd. (NGTL) Connecting Facilities that are to be constructed to provide the interconnect between the MVP and the existing NGTL facilities in Northern Alberta.[38]

The NEB held a procedural conference on 11 January 2007 and decided that the issues raised in the proposed notice of motion "would best be dealt with in a proceeding separate from the GH-1-2004 hearing."[39] In particular, the NEB stated that "while the request for directions has arisen in the context of the GH-1-2004 proceeding and the issues raised in the proposed Notice of Motion are matters related to the Mackenzie Gas Project (MGP), they do not form part of the MGP application and need not be resolved within that proceeding."[40] Accordingly, the NEB has designated certain NEB members as the NEB panel to consider the matter when filed.

In its written submission to the JRP on 26 February 2007, the Sierra Club of Canada (Sierra) took issue with the "end use" of gas transported by the Mackenzie Gas Project "to fuel expansion of the Alberta tar sands industry."[41] According to Sierra, disregarding end use of natural gas from the Mackenzie Gas Project would diminish the validity of the JRP's environmental impact assessment. In particular, Sierra submitted that the JRP's report should include the following recommendations: (i) Mackenzie gas not be used to fuel expansion of tar sands developments; (ii) Mackenzie gas be used exclusively to displace carbon-intensive fuels such as coal and oil; and (iii) Climate change adaptation and mitigation strategies be developed and implemented for affected communities and ecosystems. While acknowledging

36 *Ibid.* at paras. 6, 133.

37 Federal Court Order (30 January 2007) rendered by the The Honourable Mr. Justice Phelan.

38 NGTL applied to the AEUB on 28 June 2006 for approval to construct and operate the Connecting Facilities (Application No. 1467403). By letter dated 14 February 2007, the AEUB decided to postpone the establishment of a date for hearing pending the JRP report. See Letter from Renée Marx, Board Counsel, AEUB to Interested Parties, "Re: Application No. 1467403 NOVA Gas Transmission Ltd. (NGTL) Northwest Alberta Border to Thunder Creek Compressor Station" (14 February 2007). In this regard, the AEUB clarified that its regulatory process is independent of the JRP process; however, the AEUB noted that "[t]he environmental information gathered as part of the JRP process relating to NGTL's proposed facilities and any conditions imposed may assist the [AEUB] in its adjudication of [Application No. 1467403]."

39 Letter from Michel L. Mantha, Secretary, NEB to Mr. Robert J.M. Janes, "Re: Dene Tha' First Nation's Request for Directions in Regard to its Proposed Notice of Motion dated 30 November 2006" (2 February 2007) at 1.

40 *Ibid.* at 1.

41 Sierra Club of Canada, Written Submission, Joint Review Panel Open General Hearing, "Climate Change, The Mackenzie Gas Project and Alberta's Tar Sands," Edmonton, Alberta (26 February 2007) at 9.

that it would amount to "a significant interference in the market place," Sierra further submitted that "the NEB could prohibit, or restrict through terms and conditions in the certificate of public convenience sales of Mackenzie gas for use in fuelling tar sands projects."[42]

7. APPEAL OF NATIONAL ENERGY BOARD DECISIONS

a. *Flint Hills Resources Ltd. v. Canada (National Energy Board)*[43]

Flint Hills Resources, Ltd. (Flint Hills) appealed NEB Decision RH-1-2005[44] relating to tolls on Enbridge Pipelines Inc.'s (Enbridge) pipeline system on the basis that the NEB lacked jurisdiction to approve the recovery of certain costs included in the tolls and the basis that the NEB provided insufficient reasons. Specifically, in Decision RH-1-2005 the NEB approved Enbridge's recovery of certain non-routine adjustments that involved the inclusion of US$100 million of costs in tolls on its Canadian pipeline system. These costs were to be used to subsidize, via reduced tolls, capital costs for two United States based pipelines which would ultimately benefit Canadian shippers on Enbridge's Canadian pipeline system.[45] The Court summarized Flint Hills' position on appeal as follows:

> As we understand it, Flint Hills is asking this Court to adopt the following as a principle of law: The Board, in establishing the revenue requirement used to set the toll increase sought by Enbridge in this case, exceeded its jurisdiction when it included in that revenue requirement the cost incurred by Enbridge to finance infrastructure or infrastructure improvements that are not part of the Enbridge undertaking to which the toll relates.[46]

In dismissing the appeal from the bench the Court cited a line of cases[47] for the proposition that the NEB has broad discretion to set tolls under the *NEB Act* and hence there was no basis to bar the NEB from including costs relating to infrastructure belonging to others in Enbridge's tolls. The Court also found that the NEB provided sufficient reasons.

B. ALBERTA ENERGY AND UTILITIES BOARD

The Alberta Energy and Utilities Board (AEUB) is an independent, quasi-judicial agency of the Government of Alberta. The AEUB was created as a result of a merger between the Energy Resources Conservation Board, the Public Utilities Board, and the Alberta Geological Survey.[48] Under its mandate as set out in its enabling statute, the *Alberta Energy*

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42 *Ibid.* at 13-14.

43 2006 FCA 320, [2006] 354 N.R. 297 [*Flint Hills Resources*].

44 NEB, *In the Matter of Enbridge Pipelines Inc., Applications dated 7 January 2005 and 8 February 2005 for Orders Pursuant to Part VI of the National Energy Board Act*, Reasons for Decision, RH-1-2005 (June 2005) [Decision RH-1-2005].

45 *Supra* note 43 at paras. 1-4; *ibid.* at 1-6.

46 *Flint Hills Resources*, *ibid.* at para. 5.

47 *Trans Mountain Pipe Line v. Canada (National Energy Board)*, [1979] 2 F.C. 118 (C.A.); *TransCanada PipeLines Ltd. v. Canada (National Energy Board)*, 2004 FCA 149, [2004] 319 N.R. 171.

48 Effective 1 January 2008, the AEUB has been realigned into two separate regulatory bodies, the Energy Resources Conservation Board (ERCB), which regulates the energy industry, and the Alberta Utilities Commission (AUC), which regulates the utilities industry.

and Utilities Board Act[49] and governed by some 40 statutes, the AEUB adjudicates and regulates matters related to energy and utilities within Alberta to ensure that the discovery, development, and delivery of Alberta's energy resources and utility services take place in a manner that is fair, responsible, and in the public interest. In assessing the public interest, the AEUB has regard for social, economic, and environmental impacts through its application and hearing process, standards setting and regulation, monitoring, surveillance, and enforcement.

The AEUB may review and vary its decisions and any appeal of an AEUB decision lies with the Alberta Court of Appeal. AEUB decisions and Alberta jurisprudence of significance to oil and gas lawyers are discussed below.

1. Decision 2007-013: Imperial Oil Resources Ventures Limited[50] and Decision 2006-128: Albian Sands Energy Inc.[51]

In Decisions 2007-013 and 2006-128, Provincial/Federal Joint Review Panels granted conditional approval for Imperial Oil Resources Limited's Kearl Oil Sands Project[52] and Albian Sands Energy Inc.'s Muskeg River Mine Expansion, respectively. The Joint Review Panels in both cases imposed numerous conditions on the applicants in relation to environmental and technical aspects of the respective projects, including tailings and reclamation management. Significantly, in both cases the Joint Review Panels also emphasized the importance of "critical challenges" in the future for oil sands development.[53] In particular, the Joint Review Panels provided the following cautionary comments in the Executive Summary of each of Decision 2007-013 and Decision 2006-128:[54]

> While this project has been considered to be in the public interest, the Joint Panel must emphasize the importance of the Government of Alberta and Canada giving priority attention to critical challenges related to cumulative impacts for a number of key environmental sectors and to the acute and growing issues faced by both the Regional Municipality of Wood Buffalo and the Northern Lights Health Region. *With each additional oil sands project, the growing demands and the absence of sustainable long-term solutions weigh more heavily in the determination of the public interest.*[55]

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49 R.S.A. 2000, c. A-17 [*AEUB Act*].

50 AEUB, Decision 2007-013: *Imperial Oil Resources Ventures Limited Application for an Oil Sands Mine and Bitumen Processing Facility (Kearl Oil Sands Project) Fort McMurray Area* (27 February 2007) [Errata Included] [Decision 2007-013].

51 AEUB, Decision 2006-128: *Albian Sands Energy Inc. Application to Expand the Oil Sands Mining and Processing Plant Facilities at the Muskeg River Mine* (17 December 2006) [Decision 2006-128].

52 On 29 March 2007, Sierra Legal, on behalf of a coalition of environmental organizations, filed an application for judicial review of the Joint Review Panel's report under s. 18.1 of the *Federal Courts Act*, R.S.C. 1985, c. F-7. Sierra Legal submitted, among other things, that the Joint Review Panel erred in law and/or jurisdiction by failing to consider the environmental and cumulative effects of the Kearl Oil Sands Project, the significance of those effects, and the existence of technically and economically feasible measures that would mitigate the significant environmental effects of the Kearl Oil Sands Project.

53 *Supra* note 50 at vii; *supra* note 51 at vi.

54 Note that in both decisions, the AEUB and the Joint Review Panel states that "this executive summary is provided for the benefit of the reader and does not form part of the report. All persons making use of the executive summary are reminded that the report should be consulted for all purposes relating to the interpretation and application of the Joint Panel's views" (*ibid.*).

55 *Supra* note 50 at viii; *supra* note 51 at vi [emphasis added].

2. DECISION 2006-052: COMPTON PETROLEUM CORPORATION INTERVENER STANDING[56]

In Decision 2006-052, the AEUB ultimately denied requests for standing by several parties, including landowners who reside approximately 1.2 to 1.5 km southeast of Compton Petroleum Corporation's (Compton) proposed exploratory sweet natural gas well located within the Eastern Slopes boundaries identified in Information Letter 93-9.[57]

Compton, while acknowledging that some of the parties might be allowed to participate at a hearing if one were held, argued that none of the parties met the legal requirement for standing as established in s. 26 of the *Energy Resources Conservation Act*.[58] As such, Compton maintained that none of the parties had standing to "trigger" a hearing regarding the proposed well.

The AEUB accepted that the central issue that must be addressed is whether or not any of the parties have met the legal requirements under s. 26 of the *ERCA*, which provides that those persons whose rights may be directly and adversely affected by the approval of an energy facility are entitled to an opportunity to full participation at a hearing. The AEUB acknowledged its "long-standing practice … to allow those persons who would otherwise not have standing to participate to some extent at a public hearing provided that they offer relevant information";[59] however, the AEUB made it clear that in all cases the legal requirements of s. 26 of the *ERCA* must be triggered. Since none of the parties were able to exhibit the potential for being directly and adversely impacted by Compton's proposed well, the AEUB refused to grant standing to any of the parties in Decision 2006-052.

3. DECISION 2006-102: ENCANA CORPORATION WELL LICENCE AND FACILITY APPLICATIONS[60]

In Decision 2006-102, the AEUB approved, subject to certain conditions, EnCana Corporation's (EnCana) applications to drill 15 coalbed methane (CBM) wells, construct and operate 46 pipeline segments to tie the 15 CBM wells into the existing infrastructure, and construct and operate a 1,000 kilowatt gas compressor and inlet separator at an existing compressor station in the Torrington area.

Interveners objected to the applications on various grounds; however, the interveners' primary concern related to the potential risk posed by the 15 CBM wells to local aquifers that provide the interveners with water for domestic and stock use.[61] In particular, the interveners

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56 AEUB, Decision 2006-052: *Decision on Requests for Consideration of Standing Respecting a Well Licence Application by Compton Petroleum Corporation Eastern Slopes Area* (8 June 2006) [Decision 2006-052].

57 AEUB, Information Letter IL 93-9: "Oil and Gas Developments Eastern Slopes (Southern Portion)" (13 December 1993).

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

59 Decision 2006-052, *supra* note 56 at 4.

60 AEUB, Decision 2006-102: *EnCana Corporation, Applications for Licences for 15 Wells, a Pipeline, and a Compressor Addition Wimborne and Twining Fields* (31 October 2006) [Decision 2006-102].

61 The interveners also raised issues related to soil conservation and weed control, access roads, as well as the potential for excessive noise associated with an additional compressor.

raised concerns regarding (i) the use of surface water for drilling; (ii) surface casing; (iii) well completion/nitrogen fracturing; and (iv) water well sampling and complaint investigation. The interveners also expressed concern regarding the potential for excessive noise associated with an additional compressor.

The interveners argued that the AEUB should require EnCana to treat any dugout water it intended to use for drilling the 15 CBM wells. The AEUB disagreed while highlighting that "both EnCana and the interveners' expert witness agreed that the kinds of bacteria or other organisms present in surface water would not be able to survive underground in aquifers."[62] However, the AEUB recommended that a public report be prepared by a third party to address the issue of groundwater and water wells and CBM development using untreated surface water for drilling operations.

Regarding the issue of surface casing, the interveners requested that the AEUB require EnCana to set surface casing to the base of the Paskapoo Formation to provide additional protection to groundwater. The AEUB, while ultimately denying the interveners' request, indicated that the requirements of Directive 008,[63] Directive 009,[64] and Directive 056[65] provide for the protection of fresh water aquifers by either (i) requiring the setting and cementing of surface casing to be below the base of ground water protection (BGWP); or (ii) if surface casing is set above the BGWP, by requiring that the production casing be cemented full length. Since EnCana intended to install production casing and cement its full length, the AEUB held that EnCana met the AEUB's regulatory requirements with respect to the protection of freshwater aquifers. The AEUB further provided that "cementing the production casing full length will protect all of the formations encountered and prevent fluid migration from one formation to another."[66]

With respect to well completion and fracturing, EnCana submitted that it would be necessary to stimulate the formations with nitrogen in order to achieve gas flow from the target coals to the wellbore. The interveners submitted, among other things, that even though EnCana was not required under Directive 027[67] to assess all potential impacts prior to initiating a fracturing program, the AEUB should require EnCana to exceed regulatory requirements in this regard. The AEUB disagreed and refused to extend the application of Directive 027 to EnCana's CBM wells since EnCana's proposed fracturing program will occur at a depth in excess of 200 m and in excess of 80 m below the deepest water well within a 500 m radius.[68]

62 Decision 2006-102, *supra* note 60 at 6.

63 AEUB, Directive 008: *Surface Casing Depth Minimum Requirements* (October 1997).

64 AEUB, Directive 009: *Casing Cementing Minimum Requirements* (July 1990).

65 AEUB, Directive 056: *Energy Development Applications and Schedules* (May 2007) [Directive 056].

66 *Supra* note 60 at 10.

67 AEUB, Directive 027: *Shallow Fracturing Operations - Interim Controls, Restricted Operations, and Technical Review* (July 2007) [Directive 027].

68 Directive 027 requires that: (i) licensees must not conduct fracturing operations at depths less than 200 m unless they have fully assessed all potential impacts prior to initiating a fracturing program; and (ii) licensees are prohibited from conducting fracturing within a 200 m radius of water wells whose depth is within 25 m of proposed well fracturing depth.

The AEUB ultimately held for various reasons that EnCana's proposed fracturing process "does not present a material risk to area water wells and their associated aquifers."[69] However, the AEUB imposed the following two conditions of approval with respect to EnCana's 15 CBM wells: (i) measure the pressure between the tubing and casing annulus above the zones being fractured, note and explain any increased pressures, and report the findings to the AEUB within five days of the fracturing operation; and (ii) install a groundwater monitoring well in the deepest aquifer immediately above the Battle Formation within 50 m of the EnCana well that has the shallowest surface casing depth.[70]

On the issue of water well sampling, the AEUB confirmed that EnCana must meet the requirements of Directive 035,[71] despite the fact that Directive 035 was issued after the oral portion of the hearing had closed.[72] The AEUB further stated that it "expects EnCana to honour its commitment to test certain other wells beyond the distance required by *Directive 035*."[73]

With respect to noise impacts associated with EnCana's proposed expanded compressor station, the AEUB, relying "heavily" on EnCana's commitments to meet and in certain cases exceed the AEUB's permissible sound levels (PSL), conditioned EnCana's approval such that it "must demonstrate that noise from the expanded compressor be within 25 dBA at [an interveners'] residence,"[74] which is less than the AEUB's prescribed noise requirements.

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69 *Supra* note 60 at 13.

70 *Ibid.* at 25. With respect to ground water monitoring the AEUB further stated that (at 25):

> The water quality is to be determined prior to fracturing operations, and the water level is to be monitored continuously, commencing immediately prior to and continuing during and after fracturing operations, until the level has stabilized. The water quality testing is to be conducted in accordance with Alberta Environment's *Standard for Baseline Water-Well Testing for Coalbed Methane/Natural Gas in Coal Operations*, April 2006. The results of this monitoring are to be reported to the Board and interveners within 30 days. Thereafter, monitoring will be done on a yearly basis.… This condition will be reviewed after the findings of the Shallow Fracturing Tchnical Committee are released or a period of five years.

71 AEUB, Directive 035: *Baseline Water Well Testing Requirement for Coalbed Methane Wells Completed Above the Base of Groundwater Protection* (8 May 2006) [Directive 035].

72 Directive 035 requires that all water wells within 600 m of a proposed water well must be tested prior to drilling the CBM well, and if there is no water well within 600 m, all water wells within 800 m must be tested (*ibid.* at 1).

73 Decision 2006-102, *supra* note 60 at 16. EnCana committed to test all water wells within 400 m, 11 additional wells located between 400 m and 880 m, some springs in the area, and all high-yield water wells present within 1,000 m of an EnCana well.

74 *Ibid.* at 18-19.

4. DECISION 2006-021: AVENIR DIVERSIFIED INCOME TRUST COMMON CARRIER DECLARATION APPLICATION[75]

In Decision 2006-021, Avenir Diversified Income Trust (Avenir) applied to the AEUB under ss. 48, 55 and 56 of the *Oil and Gas Conservation Act*[76] for a common carrier order in relation to a pipeline owned by Dynegy Canada Inc. (Dynegy).[77] Dynegy intervened, opposing Avenir's application. The dispute between Avenir and Dynegy related mainly to the transportation fee to be paid by Avenir to Dynegy.

From 2001 until September 2005, Avenir and its predecessor, Val Vista,[78] paid a monthly fee of $21,988.34 to transport gas on a Dynegy pipeline under a series of agreements (the Agreements) having a three-year term ending 31 December 2004 and then continuing on a month-to-month basis. In September 2005, Avenir shut in all wells flowing gas into the pipeline and provided documents to Dynegy conveying all of Avenir's interests in the pipeline to Dynegy.

Dynegy maintained that the Agreements were still in effect and Avenir could transport gas through the pipeline at the agreed fee of $21,988.34 on a month-to-month basis regardless of the fact that Avenir had ceased flowing gas and surrendered possession of the pipeline to Dynegy on 3 September 2005. Avenir argued that the Agreements could have no further effect, at the latest by 3 September 2005, since Avenir conveyed all of its interest in the pipeline to Dynegy.

The AEUB while confirming that "as a general rule a common carrier order should not override a contract into which parties have freely entered"[79] ultimately held that the Agreements had terminated on 3 September 2005. Accordingly, the AEUB stated that "[a]fter [3 September 2005] Avenir was in the position of any other party that wished to transport gas through the pipeline and did not have an agreement to do so with Dynegy."[80]

In addressing Avenir's common carrier application, the AEUB considered both the need[81] and terms[82] of the common carrier order. In concluding that there was a need for the common carrier order, the AEUB, among other things, noted that Avenir had made reasonable

75 AEUB, Decision 2006-021: *Avenir Diversified Income Trust, Application for Common Carrier Declaration, Taber Field* (7 March 2006) [Decision 2006-021].

76 R.S.A. 2000, c. O-6 [*OGCA*].

77 A common carrier order issued by the AEUB allows an applicant to share in the capacity of another party's pipeline.

78 Val Vista was purchased by Avenir on 28 March 2005.

79 Decision 2006-021, *supra* note 75 at 4.

80 *Ibid.* at 5.

81 In this regard, the AEUB considered (i) whether there are producible reserves available for transportation in the proposed common carrier pipeline; (ii) whether there is a reasonable expectation of a market for the gas to be transported through the common carrier pipeline; (iii) whether the applicant was able to make reasonable arrangements for use of the pipeline; and (iv) whether the existing pipeline represents the only economic way or is the most practical way or is a clearly environmentally superior way to transport the gas to be produced.

82 In this regard, the AEUB considered (i) the portion of the pool subject to the order; (ii) the tie-in points to be included in the order; (iii) the effective date of the order; and (iv) the transportation fee to be included in the order.

attempts to resolve its dispute with Dynegy in relation to the fee for transport of gas. The AEUB further held that negotiations between Avenir and Dynegy were at an impasse.

With respect to the terms of the common carrier order, the AEUB held that 3 September 2005 was the appropriate effective date of the order since the Agreements had terminated on that date and that the transportation fees should be set using JP-05 methodology, noting that "the methodology to calculate fees in the JP-05 guideline was developed with the intent of establishing fees that represent fair value to both the users and owners of a facility … [and] [t]he methodology has been developed by industry and has the support of industry."[83] The AEUB rejected Dynegy's argument that the transportation fee should be determined on a cost-of-service basis since the pipeline was not "analogous to that of a regulated pipeline, where the owner provides capacity for use by others and has no intention of shipping its own product."[84]

5. DECISION 2007-024: BEARSPAW PETROLEUM LTD. REVIEW OF WELL LICENCES, COMPULSORY POOLING, AND WELL SPACING[85]

In Decision 2007-024, the AEUB considered, in the context of issuing licences under the *OGCA*, the issue of legal entitlement of coalbed methane[86] (CBM) on split-title freehold mineral lands[87] where one party owns the natural gas rights and another party owns the coal.[88]

The issue arose in the context of a review of CBM licences held by Bearspaw Petroleum Ltd., Devon Canada Corporation, and Fairborne Energy Ltd. (collectively, the Natural Gas Rights Holders). Carbon Development Partnership (CDP) and EnCana (collectively, the Coal Owners) challenged the validity of the previously approved CBM licences on the basis that as the fee simple owners of coal, they were entitled to the CBM and the Natural Gas Rights

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83 Decision 2006-021, *supra* note 75 at 13.

84 *Ibid.* The AEUB further provided that the pipeline (*ibid.*):

> cannot be equated to a regulated pipeline, as the necessary conditions, such as in a natural monopoly where economies of scale provide that efficiency of distribution is best achieved through a single supplier, are not present. If Dynegy had wanted a cost-of-service methodology to be applied throughout the life of the pipeline or after the Agreements had ended, it could have negotiated for that when the Agreements were being developed…. [A] cost-of-service methodology ensures that the users of a pipeline fulfill the revenue requirement of the owner of a pipeline and bear the risk of any excess capacity … [T]he Board concludes that the risk of any excess capacity should be borne by Dynegy, as the owner of the pipeline.

85 AEUB, Decision 2007-024: *Bearspaw Petroleum Ltd., Devon Canada Corporation, and Fairborne Energy Ltd. — Review of Certain Well Licences and Compulsory Pooling and Special Well Spacing (Holding) Orders in the Clive, Ewing Lake, Stettler, and Wimborne Fields Part 2* (28 March 2007) [Decision 2007-024].

86 CBM is the gas, primarily methane, producible from coal seams.

87 In Alberta, the Alberta Crown owns approximately 81 percent of the mineral rights by land area. The remaining 19 percent are freehold mineral rights which are owned by the federal government or privately by companies and individuals. Owners of split-title freehold mineral rights hold title to all mines and minerals except coal or all mines and minerals except coal and petroleum.

88 In March 2004, the Alberta Government amended the *Mines and Minerals Act*, R.S.A. 2000, c. M-17, such that a coal lease grants the right to coal but does not grant any rights to natural gas, including CBM. However, this amendment only applies to Alberta Crown lands where the Alberta Crown owns all the mines and minerals. See s. 67 of the *Act*.

Holders were not entitled to obtain approvals to produce the CBM. The AEUB ultimately decided that the CBM licences were properly issued.

The AEUB considered, among other things, technical evidence regarding the nature and development of CBM, the jurisdiction of the AEUB to consider the issue of legal entitlement to CBM, and the demonstration of legal entitlement to produce CBM.[89]

In relation to the technical evidence on CBM, the Natural Gas Rights Holders submitted, among other things, that coal is a container for CBM, which is natural gas, whereas the Coal Owners took the position "that CBM is intrinsic to coal in that it interacts physically and chemically with other coal constituents and should therefore be considered as a constituent of coal."[90] The AEUB concluded that "CBM is a form of gas that should be considered to be gaseous at initial (undisturbed) in situ conditions and should not be considered to be part of the coal."[91]

Regarding the AEUB's jurisdiction to consider the issue of legal entitlement of CBM, most Natural Gas Rights Holders submitted that the AEUB has such jurisdiction despite the existence of a *bona fide* dispute. Carbon Development Partnership and EnCana disagreed, for different reasons, with the Natural Gas Rights Holders. Concerning the issue of jurisdiction, the AEUB concluded:

> [It] has jurisdiction to determine whether an applicant under section 16 of the *OGCA* "is entitled to the right to produce the oil, gas, or crude bitumen from a well…" for the purpose of granting a licence, notwithstanding that there is a *bona fide* ownership, proprietary, or other legal dispute over an applicant's entitlement. Even where it is unlikely that a Board decision on ownership or other proprietary rights under section 16 of the *OGCA* will constitute a final and binding determination between the parties for all purposes, the Board finds that it must take ownership or other proprietary rights into account when deciding whether to issue a well licence.[92]

It should be noted that although the AEUB determined that it has the jurisdiction to consider the issue of legal entitlement to CBM, the AEUB made it clear that its jurisdiction is solely for the purpose of granting a licence under the *OGCA*.

With respect to the demonstration of legal entitlement to produce CBM, the AEUB accepted that the proper principles to apply are set out in the leading cases of *Borys v. Canadian Pacific Railway*,[93] *Anderson v. Amoco Canada Oil & Gas*,[94] and *Alberta Energy Co. v. Goodwell Petroleum Corp*.[95] Significantly, the AEUB also stated:

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89 In Decision 2007-024, *supra* note 85, the AEUB also considered a regulatory entitlement approach for the purposes of issuing CBM licences. This summary of Decision 2007-024 does not address the regulatory entitlement approach. In addition, the Coal Owners submitted that the AEUB should consider the strata theory of coal ownership; however, the AEUB determined the strata theory not to be relevant.

90 *Ibid.* at 6.

91 *Ibid.* at 9.

92 *Ibid.* at 10.

93 (1953), 2 D.L.R. 65 (P.C.) [*Borys*].

94 2004 SCC 49, [2004] 3 S.C.R. 3 [*Anderson*].

95 2003 ABCA 277, 339 A.R. 201.

> It is important to note that the Board is not making final or conclusive decisions that bind the parties for all purposes when it finds that an applicant is the owner or otherwise entitled to produce the resource. That ultimate authority belongs to the courts. The Board is, rather, deciding that an applicant has demonstrated entitlement to the Board's satisfaction for the purposes of issuing well licences.[96]

In *Borys* and *Anderson*, the Judicial Committee of the Privy Council and the Supreme Court of Canada, respectively, held that "in ascertaining the intention of parties to the relevant grants, reservations, or exceptions, the words in the instruments must be interpreted in the ordinary or vernacular, not the scientific sense, as used by landowners, business men, and engineers of the day and not according to the opinion of the parties to the instrument."[97]

In determining the vernacular meaning of coal and CBM at the relevant periods of time, the AEUB relied on dictionary meanings from the early 1900s to present as well as past judicial interpretations and findings. In particular, the AEUB relied on the interpretative approach of the U.S. Supreme Court in *Amoco Production Co. v. Southern Ute Indian Tribe*,[98] which the AEUB determined was "very similar to the ownership approach taken in *Borys* and *Anderson*."[99] The AEUB ultimately concluded that "the vernacular meaning of coal at the relevant times is a solid, black or blackish, combustible rock and does not include CBM. Coal is a solid in an undisturbed reservoir.… The Board considers that CBM is a distinct gaseous substance when its ordinary meaning at the relevant times is applied and is gaseous in an undisturbed reservoir."[100]

Although the AEUB held that the Natural Gas Rights Holders are legally entitled to produce CBM and their previously issued CBM licences remain valid, it is important to note that the AEUB clearly stated that "[i]n making its determination … the Board is well aware that it is not making final or conclusive decisions that bind the parties for all purposes … [but], rather, deciding that an applicant has demonstrated entitlement to the Board's satisfaction for the purpose of issuing well licences."[101] As such, the AEUB's decision with respect to the legal entitlement of CBM is limited to entitlement for the purposes of issuing licences under the *OGCA*.

The AEUB also indicated that its conclusion in Decision 2007-024 sets aside immediately the directions in Bulletin 2006-19.[102] As such, applications held in abeyance in accordance with Bulletin 2006-19 will now be processed by the AEUB. The AEUB further held that:

> [The] conclusions in [Decision 2007-027] provide a sound basis for the Board's consideration of pending and future well licence … applications involving the right to produce CBM from split-title lands where objections based on disputed entitlement or ownership to CBM are filed. That is not to say that the Board will simply dismiss such objections without any consideration of the unique facts and circumstances of the

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96 Decision 2007-024, *supra* note 85 at 27.
97 *Ibid.* at 28.
98 526 U.S. 865 (1999).
99 Decision 2007-024, *supra* note 85 at 29.
100 *Ibid.* at 31.
101 *Ibid.* at 33.
102 AEUB, Bulletin 2006-19: "Applications Involving Objections Relating to the Legal Entitlement of Coalbed Methane" (30 May 2006) [Bulletin 2006-19].

> particular objection. The Board will, however, where appropriate, consider such objections in light of the conclusions made in [Decision 2007-027], in particular about the nature of CBM and coal and the vernacular meaning of coal and CBM at the relevant time in the decision.[103]

6. DECISION 2006-105: SUNCOR ENERGY INC. PRELIMINARY DECISION REGARDING VENTURES PIPELINE (OIL SANDS PIPELINE)[104]

The AEUB's jurisdiction to conduct an investigation and to fix just and reasonable rates for a previously unregulated pipeline under the Alberta *GUA*[105] was recently considered in Decision 2006-105.

On 23 March 2006, Suncor Energy Inc. (Suncor) applied to the AEUB for, among other things, an investigation of the services and tolls applicable to the Ventures pipeline.[106] Suncor holds long-term contracts for service on the 24-inch Ventures oil sands pipeline (the Ventures Pipeline). The Ventures Pipeline is held by TransCanada Pipeline Ventures Limited Partnership (Ventures Partnership). NOVA Gas Transmission Ltd. (NGTL) holds a 99.99 percent limited partnership interest in the Ventures Partnership, while the other 0.01 percent is held by TransCanada Pipeline Ventures Ltd. (Ventures Ltd.), the general partner of the Ventures Partnership.

In its 24 October 2006 preliminary decision, the AEUB first considered the question of whether the Ventures Pipeline is a "gas utility" under the *GUA*. Suncor submitted that because the Ventures Pipeline transmits, transports, and delivers gas directly to Suncor, Williams Energy, and NGTL, it falls within the definition of "gas utility" as set out in the *GUA*. Ventures Ltd. disagreed, arguing that the Ventures Pipeline does not supply gas "to or for the public," as set out in the *GUA*'s definition of gas utility. Ventures Ltd. argued that Suncor (and Williams Energy) did not fit the definition of being a member of the public and should not be in need of regulatory protection as it is a sophisticated party that freely entered into long-term contracts for service.

The AEUB determined that the words "to or for the public or any member of the public, whether an individual or a corporation," as found in the "gas utility" definition in the *GUA*,[107] suggest a liberal reading of the provision that is broad enough to include Suncor. The AEUB further determined that Ventures Ltd. indirectly provides service to the public on the Ventures Pipeline through a "transportation by others" agreement with NGTL.[108] As such, the AEUB held that the Ventures Pipeline is serving the public and that it is a "gas utility" as defined in the *GUA*.

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103 Decision 2007-024, *supra* note 85 at 43. See also AEUB, Bulletin 2007-07: "Processing of Applications Involving Objections Relating to the Legal Entitlement of Coalbed Methane" (28 March 2007).

104 AEUB, Decision 2006-105: *Suncor Energy Inc. Preliminary Decision Regarding Jurisdiction to have the Ventures Pipeline (Oil Sands Pipeline) Regulated Under the Provisions of the Gas Utilities Act* (24 October 2006) [Decision 2006-105].

105 *Supra* note 12.

106 Suncor applied to the AEUB under ss. 24, 36 of the *GUA*. This summary only considers s. 24 of the *Act*.

107 *Supra* note 12, s. 1(1)(g)(ii).

108 Decision 2006-105, *supra* note 104 at 4.

Since the *GUA* provides the AEUB with the authority to investigate any matter concerning a gas utility, the AEUB determined that it has the jurisdiction "to conduct an investigation into the Ventures Pipeline and the affairs of its owner(s)."[109] The AEUB further concluded that it would proceed "with an investigation to determine whether the rates charged are unjust or unreasonable or unjustly discriminatory, and then determine whether further action by the Board is warranted and appropriate given the circumstances."[110] Ventures Ltd. is pursuing an application to the Alberta Court of Appeal seeking leave to appeal the AEUB's decision and the AEUB has agreed to suspend commencement of the investigation pending a ruling from the Court.

7. DECISION 2006-058: WEST ENERGY LTD. REVIEW AND VARIANCE — OFF-TARGET STATUS OF WELL[111]

In June 2006, the AEUB granted a review and variance to West Energy Ltd. (West Energy) and revoked the "first well status" previously granted to a competitor's offsetting, off-target oil well in the same pool in accordance with Interim Directive 94-2.[112] In varying its September 2005 Decision so as to impose an off-target penalty on the competing well, the AEUB dealt with two issues of interest regarding interpretation.

First, the AEUB acknowledged that the wording in ID-94-2 and s. 4.060 of the *Oil and Gas Conservation Regulations*,[113] dealing with off-target penalties may be inconsistent and that where there are differences, the *OGCR* must take precedence. The AEUB went on to consider the s. 4.060(6) requirement that the "first well" must be "capable of production" and concluded that this meant sustained production within six months of the spud date of the well.[114] In the case before the AEUB, production from the well within the six-month period was considered to be a test of the well since sustained production could not occur until appropriate production facilities were in place to handle the sour gas present in the oil. As a result, the AEUB revoked the first well status and imposed an off-target penalty.

The AEUB went on to comment on what it viewed to be a race between two operators to qualify their respective wells for first well status and to offer a warning to industry that if similar examples come to the AEUB's attention in the future, it may consider a complete or partial revocation of its first well policy.[115]

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109 *Ibid.* at 8.

110 *Ibid.* at 12.

111 AEUB, Decision 2006-058: *West Energy Ltd. Review and Variance of Alberta Energy and Utilities Board Decision Respecting Off-Target Status of Well 00/03-34-048-08W5/0, Pembina Field* (20 June 2006) [Decision 2006-058], leave to appeal to A.B.C.A. refused, 2006 ABCA 269, 397 A.R. 372.

112 AEUB, Interim Directive ID 94-2: *Revisions to Oil and Gas Well Spacing Administration* (8 March 1994) [ID-94-2].

113 Alta. Reg. 151/71, s. 4.060 [*OGCR*].

114 Decision 2006-058, *supra* note 111 at 7.

115 *Ibid.* at 8.

8. ORDER U2006-292: GENERIC COST OF CAPITAL — RATE OF RETURN ON COMMON EQUITY (ROE) FOR 2007[116]

In keeping with the AEUB's Generic Cost of Capital Decision in which the AEUB established a return on equity (ROE) formula to be applied to certain utilities under its jurisdiction, the AEUB approved an ROE for 2007 of 8.51 percent. Consistent with the AEUB's formula, this ROE was premised on a 10-year forecast Government of Canada bond average yield of 4.15 percent and an estimated 30-year forecast Government of Canada bond yield of 4.22 percent. This 2007 ROE is a 42 basis point reduction from the AEUB's 2006 ROE of 8.93 percent.

9. DECISION 2007-005: ATCO GAS SOUTH CARBON FACILITIES[117]

In July 2004, the AEUB directed, at the impetus of several interveners,[118] ATCO Gas South (AGS), an operating division of ATCO Gas and Pipelines Ltd., to file an application which would address a 2005/2006 storage plan relating to certain AGS natural gas storage facilities and natural gas producing properties (collectively the Carbon Facilities), and which would also address concerns raised previously by AGS relating to the AEUB's jurisdiction over the Carbon Facilities. The Carbon Facilities had an extensive operational and regulatory history having been in regulated utility service for approximately 50 years and used to provide one or a combination of three functions: (i) company owned gas production; (ii) operational requirements including peaking gas, seasonal storage, load balancing, and emergency supply; and (iii) revenue generation via rental of capacity to third parties and seasonal price mitigation differentials — where revenue was offset against customer rates or the cost of gas for customers. Since approximately 2000, AGS had repeatedly sought to have the Carbon Facilities removed from the AEUB's regulation and had maintained that the facilities were no longer used as a utility asset and more recently that the AEUB no longer had jurisdiction over the facilities.[119]

In August 2004, AGS submitted a storage plan application in part as a response to the AEUB's July 2004 request and in part in compliance with a previous AEUB decision[120]

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116 AEUB, Decision 2004-052: *Generic Cost of Capital AltaGas Utilities Inc., AltaLink Management Ltd., ATCO Electric Ltd. (Distribution), ATCO Electric Ltd. (Transmission), ATCO Gas, ATCO Pipelines, ENMAX Power Corporation (Distribution), EPCOR Distribution Inc., EPCOR Transmission Inc., FortisAlberta (formerly Aquila Networks), NOVA Gas Transmission Ltd.* (2 July 2004); AEUB, Order U2006-292: *2007 General Return on Equity Result* (30 November 2006).

117 AEUB, Decision 2007-005: *ATCO Gas South Carbon Facilities Part 1 Module - Jurisdiction (2005/2006 Carbon Storage Plan)* (5 February 2007) [Decision 2007-005].

118 Alberta Irrigation Projects Association, Alberta Urban Municipalities Association, Consumers' Coalition of Alberta, First Nations, Public Institutional Consumers of Alberta, and the Utilities Consumer Advocate.

119 See AEUB, Decision 2001-75: *Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates (Methodology) Proceeding and Gas Rate Unbundling (Unbundling) Proceeding - Part A* (30 October 2001); AEUB, Decision 2002-072: *ATCO Gas, a Division of ATCO Gas and Pipelines Ltd. Transfer of Carbon Storage Facilities* (30 July 2002); AEUB, Decision 2004-022: *ATCO Gas South 2004/2005 Carbon Storage Plan* (9 March 2004) [Decision 2004-022].

120 Decision 2004-022, *ibid.*

relating to the Carbon Facilities. Subsequently, the AEUB issued Decision 2005-063,[121] which addressed preliminary questions relating to the Carbon Facilities and in which the AEUB determined that the question as to whether or not the Carbon Facilities were within the AEUB's jurisdiction should be addressed through an examination of whether or not the facilities were used or required to be used, or should otherwise remain in rate base. The AEUB determined that there were two uses for the Carbon Facilities which were relevant to its analysis: (i) revenue generation; and (ii) distribution system load balancing. Subsequently, Decision 2006-098[122] concluded that the Carbon Facilities were not used or required for utility load balancing service and should not otherwise remain in rate base. However, Decision 2007-005 found that the Carbon Facilities should be used or required to be used for revenue generation and as such, should remain in rate base and subject to the AEUB's jurisdiction. The AEUB articulated that ordinarily, revenue generation on a stand-alone basis would not typically satisfy the used or required to be used test for inclusion in rate base and any determination of that test must be made subjectively in light of the circumstances surrounding the particular assets being considered. In keeping with this, the AEUB indicated that its decision was based on the unique, historical, and current circumstances related to the Carbon Facilities. In particular, these circumstances included:

(i) The multiple purposes for which the Carbon Facilities were employed, including: company owned production, operational security, system balancing, peaking supply, emergency use, and revenue generation;

(ii) Revenue generation was part of the reason why the Carbon Facilities were used or required to be used from the time they were converted from a producing facility to storage facility and why the facility went through various evolutionary stages as a storage facility over the past 40 years. There had historically been little to no opposition to revenue generation and the use of that revenue for establishing just and reasonable rates; and

(iii) The significant impact on rates that the Carbon Facilities revenue generation function had provided during the majority of the time they operated and the fact that revenue generation had played an important role to the satisfaction of all parties throughout the history of the Carbon Facilities.

In making its decision, the AEUB noted that there is a lack of clarity as to the historical degree of usage of the Carbon Facilities for revenue generation and that it may not be appropriate for 100 percent of the facilities to continue in rate base or for 100 percent of the revenue generated by those rate base assets be used to offset revenue requirement. Consequently, the AEUB indicated that a further process (the Part 1B Process) would be established by which it would determine whether 100 percent of the Carbon Facilities are to be included in rate base and used to offset revenue requirement. The AEUB went on to indicate that upon a decision being issued in relation to the Part 1B Process, the AEUB

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121 AEUB, Decision 2005-063: *ATCO Gas South 2005/2006 Carbon Storage Plan Preliminary Questions* (15 June 2005).

122 AEUB, Decision 2006-098: *ATCO Gas Decision 2006-098 (Errata) Retailer Service and Gas Utilities Act Compliance Phase 2 Part B Customer Account Balancing and Load Balancing* (7 November 2006).

would direct AGS to file an application consistent with that decision which would address issues relating to an existing storage lease and/or the removal of certain assets from rate base.

The AEUB determined that in order to remove the Carbon Facilities from regulation the consent of the AEUB under s. 26 of the *GUA* would be required. To obtain that approval, AGS would have to demonstrate that the removal of the facilities from rate base satisfies the no-harm test. Citing the Supreme Court of Canada's decision in *ATCO*,[123] the AEUB stated:

> Although, the Court was considering a sales transaction, these words[124] seem equally appropriate to a removal of an asset from rate base out of the ordinary course of business. It would be incomprehensible that a utility could cause harm to ratepayers by circumventing the Board approval process under section 26(2)(d)(i) by simply removing an asset from rate base and declaring it to be non-utility and thereafter retaining all economic benefit therefrom, when it would be unable to realize that economic benefit through a sale transaction without first obtaining Board approval, thereby accomplishing indirectly what it could not do directly. The legislation is intended to prevent diminution of service or adverse rate impacts from the disposition of assets out of the ordinary course. The unilateral removal of a major asset from rate base outside of the ordinary course raises the same potential for harm to ratepayers as does a sale, mortgage or other disposition of such property. Accordingly, the Board considers that AGS will require the consent of the Board pursuant to section 26(2)(d)(i) of the GU Act prior to any removal of Carbon assets from rate base and prior to operating such assets as non-utility property.[125]

10. APPEAL OF ALBERTA ENERGY AND UTILITIES BOARD DECISIONS AND RELATED JURISPRUDENCE

a. *Milner Power Inc. v. Alberta (Energy and Utilities Board*)[126]

In *Milner*, the Alberta Court of Queen's Bench considered the extent to which the Court has jurisdiction to grant judicial review of a decision of the AEUB as well as the AEUB's standing to bring an application to strike an application for judicial review.

Milner Power Inc. (Milner) sought judicial review of the AEUB's refusal to grant Milner a hearing requested in a complaint application filed by Milner against the AEUB in August 2005.[127] Milner argued that it was entitled to judicial review of the AEUB's decision not to provide the complete record that was before the AEUB to the Alberta Court of Appeal *until* leave to appeal had been granted by the Court of Appeal.[128]

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123 *Supra* note 11.

124 Here the AEUB cited the following excerpt from *ATCO, ibid.* at 43: "I would note in passing that this power [under s. 26 of the *Gas Utilities Act*] is sufficient to alleviate the fear expressed by the Board that the utility might be tempted to sell assets on which it might realize a large profit to the detriment of ratepayers if it could reap the benefits of the sale."

125 Decision 2007-005, *supra* note 117 at 33.

126 2006 ABQB 537, 402 A.R. 378 [*Milner*].

127 In December 2005, the AEUB issued a decision dismissing the complaint and denying Milner's request for a hearing. In January 2006, Milner filed a notice of motion for leave to appeal to the Alberta Court of Appeal. Leave was granted, and the Court of Appeal handed down its decision on 21 August 2007, affirming the Trial Court's decision. See 2007 ABCA 265, 80 Alta. L.R. (4th) 35.

128 Subject to the granting of leave, an appeal lies to the Court of Appeal from the AEUB on a question of law or jurisdiction under s. 26 of the *AEUB Act*, *supra* note 49.

On the issue of standing, the Court held that the AEUB was not prohibited from bringing an application to strike Milner's originating notice. In particular, the Court stated "if no one comes forward to support the position … that this Court does not have jurisdiction to consider a judicial review, surely the [AEUB] itself is permitted to take that position."[129] The Court further provided that the AEUB was neither attempting "to defend the wisdom of its order" nor "arguing the merits of its decision at all."[130] Rather, the AEUB was "simply saying that the legislation gives Milner an alternative remedy and that this Court ought not be involved."[131]

In support of its judicial review application Milner argued, among other things, that "[i]ts ground of attack lies outside the record on appeal and, thus, can only be reached adequately by [judicial review]."[132] However, the Court held that there were no special circumstances which might override the adequacy of an appeal to the Court of Appeal. The Court confirmed that it has the jurisdiction to grant judicial review but refused to exercise that jurisdiction in this case, stating:

> [T]he legislature of this province has attempted to limit the intervention of the courts in the decisions of the Board. The courts of this country have repeatedly determined even where there is a privative clause, the remedy of judicial review will be available. However, where, as in [the *AEUB Act*], the legislature not only has a strict privative clause but has allowed for a statutory appeal to our Court of Appeal, the discretion to permit judicial review should be exercised cautiously.[133]

b. *Direct Energy Regulated Services v. Alberta (Energy and Utilities Board)*[134]

In *Direct Energy*, the Court of Appeal allowed in part Direct Energy Regulated Service's (Direct Energy) application for leave to appeal AEUB Decision 2005-105.[135] Direct Energy sought leave to appeal on grounds of procedural fairness as well as with respect to whether, contrary to s. 5(a) of the *Default Gas Supply Regulation*[136] and the *Regulated Default Supply Regulation*,[137] the AEUB failed to provide Direct Energy with a reasonable opportunity to recover prudent customer care costs and expenses incurred in 2004.

After stating the usual test that "leave will only be granted if the applicant demonstrates that the appeal raises a serious arguable issue on a question of law or jurisdiction which has a reasonable prospect of success,"[138] the Court of Appeal refused to grant leave on the procedural fairness grounds since "the Board's hearing process was procedurally fair in the

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129 *Supra* note 126 at para. 23.
130 *Ibid.*, citing *Alberta Energy Co. v. Goodwell Petroleum Corp.*, 2003 ABCA 277, 339 A.R. 201; *Canadian Pacific Air Lines v. C.A.L.P.A.*, [1988] 2 F.C. 493.
131 *Milner, ibid.*
132 *Ibid.* at para. 38.
133 *Ibid.* at para. 43.
134 2006 ABCA 165 [*Direct Energy*].
135 *Direct Energy Regulated Services Benchmarking Study of Customer Care Services* (13 September 2005).
136 Alta. Reg. 184/2003.
137 Alta. Reg. 168/2003.
138 *Supra* note 134 at para. 2.

sense that [Direct Energy] had full opportunity to participate in the hearing in a meaningful way."[139]

The Court of Appeal granted leave to appeal on the second ground on the basis that "[i]t is at least seriously arguable that the Board in making the directions that it did … ought to have foreseen that [Direct Energy] would not be given the opportunity to recover all of its prudently incurred customer care costs"[140] — an issue which the Board later confirmed "has reasonable prospect of success."[141]

c. *Graff v. Alberta (Energy & Utilities Board)*[142]

In *Graff*, Barbara Graff and Darrell Graff (the Graffs) sought leave to appeal the AEUB's decision in which the AEUB dismissed the Graffs' objections and declined to review the issuance of a sour gas well licence issued to EnCana Corporation. The Graffs, whose residence is located approximately 2 km from the proposed well site, opposed the proposed sour well on the basis that its proximity to their residence would directly affect them and have an adverse effect on "their already compromised medical condition, a condition known as chemical encephalopathy."[143]

The AEUB, relying on s. 26 of the *ERCA*, dismissed the Graffs' objections and declined to review their decision on the basis that "the Graffs failed to demonstrate they were potentially directly and adversely affected because [AEUB] Directive 056 requires the operator to consult only with residents within the greater of 0.2 km or the calculated EPZ (0.14 km)."[144]

The Graffs submitted, among other things, that the AEUB misinterpreted Directive 056 and fettered its discretion by improperly relying on Directive 056 to deny the Graffs the opportunity to make submissions regarding the direct and adverse impact the proposed sour well may have on their health sensitivities. The Graffs further argued that Directive 056 merely establishes "a minimum level of consultation and that it requires consultation specifically with those who have special needs, including those with pre-existing medical conditions."[145]

The Court of Appeal allowed the Graffs' application for leave to appeal since "the applicants raise a serious, arguable point which is of significance both to the practice and the action itself, and is potentially meritorious."[146] In particular, the Court of Appeal granted leave to appeal on the grounds that the AEUB, among other things, "erred in law or jurisdiction by granting the licence without affording the applicants a proper opportunity to

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139 *Ibid.* at para. 6.
140 *Ibid.* at para. 15.
141 *Ibid.*
142 2007 ABCA 20 [*Graff*].
143 *Ibid.* at para. 2. Chemical encephalopathy is asthma exacerbated by excessive sensitivity to chemicals, including emissions from the venting, flaring, and incineration of natural gas.
144 *Ibid.* at para. 4; Directive 056, *supra* note 65.
145 *Ibid.* at para. 5.
146 *Ibid.* at para. 9. The Court of Appeal applied the test for leave to appeal as set out in *Atco Electric Ltd. v. Alberta (Energy & Utilities Board)*, 2003 ABCA 44 at para. 17.

be heard, by disregarding, misapplying, or misinterpreting Directive 56, by improperly fettering its discretion, [and] by failing to properly apply s. 26 of the ERCA."[147]

d. *826167 Alberta Inc. v. Alberta (Energy & Utilities Board)*[148]

In *826167 Alberta*, certain landowners applied for leave to appeal from the AEUB's decision to grant Imperial Oil Resources Limited's (Imperial Oil) application to drill 28 natural gas wells.[149] The Court of Appeal ultimately granted the landowners' application for leave to appeal on two questions: (i) did the AEUB err in law or jurisdiction by restricting the nature of the decision it could have made (for example, denying the application or attaching conditions to a permit) and/or restricting matters it could take into account in reaching its decision; and (ii) did the AEUB err by making patently unreasonable findings of fact?

In granting leave to appeal, the Court of Appeal criticized the AEUB's reasoning in Decision 2006-037. In particular, the Court of Appeal stated that some of the AEUB's findings are "arguably inconsistent"[150] and that "clarity is lacking in parts of [Decision 2006-037], and other parts are subject to more than one interpretation."[151]

The Court of Appeal further provided that "[t]hese difficulties are exacerbated because there can be a blurring between the two topics that are central to [Decision 2006-037], operational issues and compensation matters."[152] For instance, the Court of Appeal remarked that:

> [D]espite the Board's finding regarding Imperial Oil's unwillingness to negotiate compensation, it would not comment on matters that were strictly compensation.… While it is clear from [Decision 2006-037] (and undisputed) that the Alberta Surface Rights Board has the power to set surface compensation and this Board does not, when the Board's statement is read in the context of [Decision 2006-037] it is not clear whether it considered Imperial Oil's conduct in regard to surface compensation issues as relevant to its decision-making process.[153]

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147 *Graff*, *ibid.*
148 2006 ABCA 305 [*826167 Alberta*].
149 AEUB, Decision 2006-037: *Imperial Oil Resources Limited Applications for Well Licences and Pipelines, Bantry Field* (2 May 2006) [Decision 2006-037].
150 *826167 Alberta*, *supra* note 148 at para. 8.
151 *Ibid.* at para. 4.
152 *Ibid.*
153 *Ibid.* at para. 7.

e. Reports on the Investigation into the Disclosure of Personal Information: Alberta Energy and Utilities Board[154] and West Energy Ltd.[155]

On 19 March 2007, the Office of the Information and Privacy Commissioner of Alberta (OIPC) issued two companion reports relating to the disclosure of personal information collected in the course of a participant involvement program associated with two well applications to the AEUB. The OIPC initiated its investigations of the AEUB and West Energy Ltd. (West Energy) under the *Freedom of Information and Protection of Privacy Act*[156] and the *Personal Information Protection Act*[157] respectively.

During the participant involvement process in support of two non-routine sour oil well licence applications, West Energy collected personal information from residents in the vicinity of the proposed well sites and subsequently compiled and submitted this information to the AEUB. The information was collected to complete the requisite line list under Directive 056[158] and to complete the emergency response plan for the applied for wells under the AEUB's Directive 071.[159] A combination of Directive 056 and 071 information was submitted electronically via the AEUB's Integrated Application Registry (IAR) and was subsequently posted on the AEUB's website. Additionally, to facilitate intervener pre-hearing access to its applications, West Energy distributed compact disc (CD) copies and hard copies of its application and also placed copies at a public location within the community. West Energy had removed most, but not all, of the personal information from its applications prior to distributions.[160]

The OIPC conducted two separate investigations: one into the AEUB's collection and disclosure of the personal information via its website, and the other into West Energy's collection and disclosure of personal information to both the AEUB and to interveners and the public. With respect to the AEUB, the OIPC concluded that, consistent with the *FOIP Act*, the AEUB had express statutory authority to indirectly, through West Energy, collect the both Directive 056 and Directive 071 personal information that was submitted as part of West Energy's applications.[161] Regarding the AEUB's disclosure of the personal information on the AEUB's website, again the OIPC concluded that in accordance with the *FOIP Act*, the AEUB had express statutory authority to disclose the personal information required under Directive 056, including acknowledgment of an objection as part of a well application. However, the OIPC concluded that the AEUB lacked authority to disclose emergency

[154] Office of the Information and Privacy Commissioner (OIPC), Investigation Report F2007-IR-002: *Report on an Investigation Regarding the Disclosure of Personal Information By the Alberta Energy and Utilities Board (Investigation #F3882)* (7 March 2007) [F2007-IR-002].

[155] OIPC, Investigation Report P2007-IR-003: *Report of an Investigation into the Disclosure of Personal Information West Energy Ltd. Investigation Report* (19 March 2007) [P2007-IR-003].

[156] R.S.A. 2000, c. F-25 [*FOIP Act*].

[157] S.A. 2003, c. P-6.5 [*PIPA*].

[158] *Supra* note 65.

[159] AEUB, Directive 071: *Emergency Preparedness and Response Requirements For the Upstream Petroleum Industry* (20 July April 2005) [Directive 071].

[160] F2007-IR-002, *supra* note 154 at 1-4; P2007-IR-003, *supra* note 155 at 1-4.

[161] F2007-IR-002, *ibid.* at 5-8. The statutory authority arose under s. 26 of the *ERCA*, *supra* note 58, s. 4, and various AEUB policy documents.

response planning information collected under Directive 071 and did not make reasonable security arrangements to prevent disclosure.[162]

Consistent with the OIPC having concluded that collection of the personal information by the AEUB indirectly through West Energy was statutorily authorized, the OIPC also concluded that West Energy did not require the consent of those whose personal information had been collected to disclose the personal information to the AEUB, because as required by the *PIPA*, the disclosure was for reasonable purposes. Similarly, the OIPC concluded that West Energy did not require consent to disclose the personal information to interveners in hard copy and CD form as, consistent with the *PIPA*, the disclosure was reasonable as it occurred as part of the public hearing process. However, the OIPC concluded that although the purpose for the disclosures was reasonable, the extent of the disclosures was not reasonable within the meaning of the *PIPA* as the disclosures included Directive 071 personal information that was not required by the AEUB to process the well applications. In effect, West Energy erred when it submitted to the AEUB and published its applications containing a line list that combined the requirements of Directive 071 with Directive 056.[163]

As a result of its investigations, the OIPC made several recommendations, including that the AEUB: review its personal information collection and disclosure practices to determine what needs to be disclosed; provide clear direction to applicants that Directive 056 information to be submitted via the IAR is separate from Directive 071 information; update the IAR to include prompts so applicants do not submit unnecessary personal information; ensure notification on its website and documentation provided to stakeholders is clear regarding what personal information needs to be collected and how it will be used and disclosed; and provide privacy training to its applications staff.

The OIPC recommended that West Energy undertake the following steps: train its newly appointed Privacy Officer in the requirements of privacy legislation and compliance; ensure that someone trained in privacy reviews the AEUB personal information requirements with respect to AEUB applications; ensure that someone trained in privacy review all licence applications and supporting documents prior to disclosure to the AEUB and other stakeholders; develop a privacy policy that specifically addresses the use and disclosure of personal information for the purposes of AEUB applications; and that West Energy ensure that all agreements with contractors relating to participant involvement programs include a provision relating to compliance with privacy legislation and West Energy's privacy policy.

Finally, the OIPC found as part of its investigations that the AEUB's and West Energy's disclosure of unnecessary personal information was inadvertent.

C. ALBERTA SURFACE RIGHTS BOARD

Where an operator and a landowner or an occupant fail to reach an agreement regarding entry or compensation related to resource activity on privately-owned or Crown-occupied

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162 F2007-IR-002, *ibid.* at 8-10, 13. The statutory authority arose under s. 12 of the *Alberta Energy and Utilities Board Rules of Practice*, Alta. Reg. 101/2001.

163 P2007-IR-003, *supra* note 155 at 6-12.

lands, under the *Surface Rights Act*[164] the Alberta Surface Rights Board (SRB) may, among other things, grant right of entry to the operator and determine compensation for such entry.

1. COMPENSATION FOR TEMPORARY WORKSPACE

In relation to the construction of its Corridor Pipeline, Corridor Pipeline Limited[165] (Corridor or Operator) applied for, and was granted, various right of entry orders (REO) by the SRB. Typically, REOs include a right of entry relating to two separate areas: the right of way (ROW) and adjacent temporary work space (TWS or Temporary Workspace) required only on a temporary basis during the construction phase. Among the orders granted for the Corridor Pipeline was one regarding property owned by Dalton, Gertrude, and Darwin Trenholm (the Trenholms) located at SE 10-62-20-W4, Right of Entry Order No. 1755/2001 (the Trenholm REO).

In the Trenholm REO, the SRB imposed a typical condition (Condition 8) that, upon completion of construction, Corridor was required to obtain a reclamation certificate before requesting partial termination of the REO with respect to the TWS. Under s. 28 of the *SRA*, the SRB will not grant an order for termination of a REO until such time as the operator of the pipeline has obtained a reclamation certificate. Reclamation certificates are within the jurisdiction of Alberta Environment and are issued under the *Environmental Protection and Enhancement Act*.[166] Reclamation refers to putting the land back into its pre-right of entry condition and the reclamation certificate process was meant to ensure operators' compliance with the *EPEA*.

On 22 September 2004, the Trenholms wrote to the SRB to request a hearing on the issue of additional compensation for TWS.[167] The Trenholm request was expressly made as a test case since there are other landowners on the Corridor Pipeline route that are affected by similar REOs. A hearing was set for 28 September 2005 in Edmonton. The Trenholm claim stems from a loop-hole created by a legislative conflict between the *SRA* and the *EPEA*. The SRB historically has awarded more compensation for land designated as ROW as opposed to land designated as TWS. Alberta Environment, as a matter of policy, will not issue reclamation certificates under the *EPEA* to an operator until such time as the operator has abandoned the pipeline. Conversely, the *SRA* does not empower the SRB to grant an order for termination of a REO until such time as the operator of the pipeline has obtained a reclamation certificate from Alberta Environment.

In the face of these policies, Corridor did not make applications for reclamation certificates on the Corridor Pipeline. The only apparent consequences of this legislative conflict appeared to be that Corridor would be precluded from complying with certain conditions of REOs (Condition 8 in the Trenholm REO), and REOs for TWS would not be discharged. The possibility of an additional consequence — a potential increase in

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

[165] Now Terasen Pipelines (Corridor) Inc.

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

[167] The Trenholms requested a review of SRB, Decision 2002/0208 (4 November 2002) [note that this decision forms part of a group consisting of 98 SRB decisions: SRB, Decisions 2002/0144-2002-0241]; SRB, Compensation Order No. 3471/2002.

compensation for TWS — did not arise until 2004, when the Trenholms requested the SRB hearing. The Trenholms argue that because Corridor cannot fulfill its obligation to discharge the Trenholm REO as it relates to the TWS, the TWS has *de facto* become a permanent right of way. As such, the Trenholms submit that they are entitled to compensation for TWS at the greater rate applicable for ROW rather than the existing rate of compensation for TWS as set out in Compensation Order No. 3471/2002.

In addition to pursuing legal options, Corridor initiated policy discussions with Alberta Environment. In order to avoid adjudication by the SRB before Alberta Environment was presented with the formal administrative consideration of this matter, Corridor submitted an application for a reclamation certificate for the Trenholm TWS in September 2005. In the interim, the SRB granted Corridor an adjournment of the 28 September 2005 hearing pending the resolution of the reclamation certificate issue. On 23 September 2005, Corridor received notice from Alberta Environment that its application for a reclamation certificate for the Trenholm TWS was rejected.

Corridor appealed Alberta Environment's decision to the Alberta Environmental Appeals Board (AEAB) on 10 November 2005.[168] As part of the appeal process, the parties were encouraged to participate in AEAB-sponsored mediation. That process included the Trenholms as interveners, Alberta Environment, and Corridor. Alberta Environment's initial position was that it would not issue a reclamation certificate for the Trenholm TWS. This was motivated by concerns of setting a precedent and perhaps encouraging additional requests by landowners for reclamation certificates before the necessary Alberta Environment policy and infrastructure was in place. The Operator persuaded Alberta Environment to revisit its position and the parties are now working to develop a policy that would allow the Operator to obtain a reclamation certificate for the Trenholm TWS and also allow the ongoing use of TWS for construction by all operators. In order to expedite potential resolution, Alberta Environment and Terasen requested an adjournment of the AEAB mediation process while the parties work directly with each other to resolve the matter without landowner involvement.

The parties are developing a template for a Reclamation Certificate Application for TWS. Should this process fail, it is unlikely that any resolution could be achieved through re-entering AEAB Mediation. Although Alberta Environment and landowners generally support the continued use of TWS, Alberta Environment's lack of human and financial resources hampers Alberta Environment's ability to commit to policy changes without consultation with the Minister of Environment. A successful appeal to the AEAB or, should it be required, to the Courts would force the Minister of Environment to resolve the matter.

In a separate proceeding, on 26 October 2006 the SRB issued its decision in *Terasen Pipelines (Corridor) Inc. and R&M Schroter Enterprises Ltd.*[169] In *R&M*, the SRB, relying on the legislative contraction between the *SRA* and the *EPEA* as set out above, ordered the

168 AEAB Notice of Appeal (10 November 2005).

169 SRB, Decision 2006/0148; SRB, Decision 2006/0149; SRB, Decision 2006/0150; SRB, Decision 2006/0151; SRB, Compensation Order 1050/2006; SRB, Compensation Order 1051/2006; SRB, Compensation Order 1052/2006; SRB, Compensation Order 1053/2006 [*R&M*].

Operator to pay additional compensation to landowners for TWS at the rate equal to that paid for ROW. On 30 November 2006, Corridor submitted a notice of appeal to have the SRB's decision in *R&M* reviewed in the Alberta Court of Queen's Bench.

2. ALBERTA SURFACE RIGHTS BOARD AND RELATED JURISPRUDENCE

a. *R. v. Strom*[170]

Mr. Strom was charged with engaging in the activities of a land agent without a licence under the *Land Agents Licensing Act*.[171] Strom had held himself out as an advocate for agriculture and promoted that he represented landowners in negotiations and had in fact represented landowners with respect to two separate incidents involving negotiations for surface rights leases and one incident involving negotiations for a utility right-of-way. During the course of these negotiations, Strom sought compensation from the operator seeking to acquire land rights from Strom's clients.

In convicting Strom, the Court considered the meaning and interpretation of "land agent" within the *Licensing Act* and concluded that it included persons who, for a fee, advise people with respect to engaging in activity connected with negotiations to dispose of an interest in land. Additionally, the Court dismissed an argument that the *Licensing Act* breached Strom's s. 7 rights under the *Canadian Charter of Rights and Freedoms*,[172] on the basis that there was insufficient evidence before the Court to determine whether the *Licensing Act* was overly vague or overly broad so as to deprive Strom of his right to life, liberty, and security of person. Additionally, the Court went on to conclude that even in the absence of evidence, Strom's s. 7 *Charter* rights were not breached as the impugned provision of the *Licensing Act* was neither overly vague nor overly broad.

The Court also stated that the *Licensing Act* created an unbalanced playing field favouring the oil and gas industry over landowners and for that reason may require revision.

D. OFFSHORE PETROLEUM BOARDS

There are two offshore Petroleum Boards regulating oil and gas development off of Canada's east coast. The Canada-Newfoundland and Labrador Offshore Petroleum Board (CNLOPB) and the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB). The CNLOPB was established in 1985 and is a federal-provincial authority that administers portions of the *Canada-Newfoundland Atlantic Accord Implementation Act* and *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*.[173] The CNSOPB was established in 1990[174] and is a federal-provincial authority that administers portions of the *Canada-Nova Scotia Offshore Petroleum Resources Accord*

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[170] 2007 ABPC 91, 73 Alta. L.R. (4th) 115.

[171] R.S.A. 2000, c. L-2 [*Licensing Act*].

[172] Part 1 of the *Constitution Act, 1982*, being Schedule B to the *Canada Act 1982* (U.K.), 1982, c. 11 [*Charter*].

[173] S.C. 1987, c. 3; R.S.N.L. 1990, c. C-2 [collectively, *NFLD Accord Acts*].

[174] CNSOPB, *1989-1990 Annual Report* (19 June 2000), online: CNSOB <http://www.cnsob.ns.ca/archives/pdf/English2.pdf> at 3.

Implementation Act and *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act*.[175] Under their respective legislative regimes, the CNLOPB and CNSOPB both generally regulate various aspects of energy development offshore of each of Newfoundland and Nova Scotia respectively, including: sale of interest in lands; issuing exploration and production licences; resource evaluation and data collection; and overseeing offshore development projects in relation to safety, environmental protection, and resource management.[176]

1. DECISION 2006.02: HIBERNIA DEVELOPMENT PLAN AMENDMENT[177]

In December 2006, the CNLOPB approved, with conditions, an application from the Hibernia Management and Development Company to amend its previously approved Hibernia Development Plan[178] to permit the drilling of 16 wells in the Southern Extension of the Hibernia Reservoir and to implement a gas flood scheme in a portion of the existing Hibernia development area.[179] In making its decision the CNLOPB considered a number of issues,[180] the majority of which were addressed via conditions on the approval including:[181] (1) filing with the CNLOPB copies of commercial agreements between resource interest owners as well as filing confirmation that royalty owners concur with such agreements prior to initiating production — the CNLOPB required this to ensure that the commercial terms were consistent with the intent of governing legislation to avoid waste of the resource;[182] (2) filing with the CNLOPB a report detailing an assessment and evaluation of de-bottlenecking and expansion options for production facilities as well as an evaluation of additional drill slots on the Hibernia platform — the CNLOPB required this as the development plan amendment was premised on using, and expanding, the existing Hibernia platform facilities which are fully utilized;[183] (3) filing with the CNLOPB an exploitation plan for the oil, natural gas, and natural gas liquids in the Hibernia field including an assessment of facility life — the CNLOPB noted that the design life of the Hibernia production facility was 30 years and in order to address the conservative oil reserve potential in the application and the significant upside potential of natural gas and natural gas liquids currently supporting oil production, an exploitation plan for oil and natural gas in the Hibernia field is required;[184] and (4) after approval of the CNLOPB's decision by the

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175 S.C. 1988, c. 28; S.N.S. 1987, c. 3 [collectively, *NS Accord Acts*].

176 See the CNLOPB website, online: CNLOPB <http://www.cnlopb.nl.ca/> and the CNSOPB website, online: CNSOPB <http://www.cnsopb.ns.ca>. Please note that decisions issued by the CNLOPB and the CNSOPB, respectively, may be accessed via these websites.

177 CNLOPB, Decision 2006.02: *Respecting an Amendment to the Hibernia Development Plan* (December 2006) [Decision 2006.02].

178 CNLOPB, Decision 90.01: *Updating Decision 86.01 Application of Approval Hibernia Development Plan Update* (August 1990). See also CNLOPB, Decision 97.01: *Respecting the Amendment to the Hibernia Development Plan* (March 1997); CNLOPB, Decision 2000.01: *Respecting the Amendment to the Hibernia Development Plan* (March 2000); CNLOPB, Decision 2003:01: *Respecting the Amendment to the Hibernia Development Plan* (March 2003); CNLOPB, Decision 2006.01: *Respecting the Amendment to the Hibernia Development Plan* (January 2006).

179 *Supra* note 177 at 1-4.

180 *Ibid.* at 2.

181 *Ibid.* at 6.

182 *Ibid.* at 30.

183 *Ibid.* at 50-51.

184 *Ibid.* at 2, 44-47.

Ministers,[185] filing with the CNLOPB an amended Hibernia Benefits Plan[186] — the CNLOPB noted that the originally approved Hibernia Benefits Plan did not adequately address legislated requirements relating to research and development, education and training, and affirmative action programs/funding as outlined in the CNLOPB's recently amended CNLOPB Benefits Guidelines.[187] It is important to note that in imposing this condition the CNLOPB stated that it would normally require the benefits plan amendment in advance of approving the development plan amendment, but in the interest of expediency, it decided to require the amendment as a condition of approval.[188]

As required by its enabling legislation, the CNLOPB provided notice to the Ministers of the decision and sought their approval.[189] The provincial Minister subsequently disapproved of the CNLOPB decision primarily on the basis that the issues addressed through the conditions of the approval are of interest to Newfoundland and the use of conditions will effectively prevent the Province from having a formal role in ensuring its concerns in relation to the issues are addressed.[190] In particular, the Minister took issue with approving the amended development plan in the absence of an approved Benefits Plan.[191] The Minister, in disapproving of the decision, also cited insufficient information relating to: modes of development via either potential upgrades to the Hibernia platform facilities premised on pending assessments or alternate potential modes of development; commercial and financial issues relating to multiple licensees and commercial agreements for production in the absence of unitization and related concerns regarding royalty and tax payments; facility constraints including water and gas processing constraints and drilling slot constraints; secondary reservoirs production being delayed or being left undeveloped in favour of production from the southern extension thereby potentially affecting ultimate recovery; and no information relating to the future development of natural gas from the Hibernia field.[192]

The CNLOPB replied to the provincial Minister first by noting that despite the province being fully informed of the application and its contents and despite numerous meetings between the province and the CNLOPB, the province failed to raise any concerns regarding insufficient information until after the decision was published. Second, the CNLOPB replied to each of the concerns raised by the Minister in disapproving the decision, by effectively providing additional reasoning for why the CNLOPB approved the application. Finally, the

185 *Supra* note 173, ss. 31, 32 of each *Act* require the CNLOPB to implement any decision only after obtaining approval of both the federal and provincial ministers.

186 *Ibid.* Section 35 of each *Act* requires a benefit plan be approved by the CNLOPB, unless the CNLOPB directs the requirement need not be complied with, prior to any development plan approval being issued. The Hibernia Benefits Plan was originally approved in CNLOPB, Decision 86.01, referred to in *supra* note 178.

187 CNLOPB, *Canada-Newfoundland and Labrador Benefits Plan Guidelines* (February 2006), online: CNLOPB <http://www.cnlopb.nl.ca/>.

188 *Supra* note 177 at 18.

189 See discussion contained in *supra* note 185.

190 Letter from Kathy Dunderdale, MHA, Minister of Natural Resources, Government of Newfoundland and Labrador, to Max Ruelokke, Chairman & CEO, CNLOPB (17 January 2007), online: Government of Newfoundland and Labrador <http://www.releases.gov.nl.ca/releases/2007/nr/letterjan17.pdf> at 2.

191 *Ibid.* at 5.

192 *Ibid.* at 3-5.

CNLOPB requested that the Ministers (federal and provincial) and senior government officials meet to discuss the matters raised by the province of Newfoundland.[193]

2. White Rose Development Plan Amendment Production Increase[194]

In September 2006, the CNLOPB received an application from Husky Oil Operations Limited (Husky) to amend the previously approved White Rose Development Plan[195] to permit increased annual and daily production rates from 100,000 to 140,000 bpd.[196] The CNLOPB sought public comment on the application until 19 January 2007 and a decision is pending.

3. Deep Panuke Offshore Gas Development Plan Application[197]

In September 2006, the CNLOPB received a development plan application from EnCana seeking approval to develop the Deep Panuke gas pool offshore of Nova Scotia. In 2002, EnCana had previously sought such approval but in 2003 subsequently withdrew its application. The EnCana Deep Panuke development plan application seeks approval to produce gas from four existing wells and one new well and also seeks approval to construct associated production facilities. If approved, EnCana anticipates the first gas flow to occur in 2010.[198] EnCana filed a related pipeline application with the NEB seeking approval to construct 176 km of pipeline from the Deep Panuke production facilities to the Maritimes and Northeast Pipeline.[199] EnCana's other pipeline option is a 15 km line to connect to the Sable Offshore Energy Partnership sub-sea pipeline. EnCana requested that the 176 km line be approved without foreclosing EnCana's ability to opt for the 15 km option if appropriate commercial terms are negotiated with Sable Offshore Energy Partnership to use its line. To facilitate a joint review of the applications, the CNSOPB and the NEB established the Deep Panuke Coordinated Public Review Secretariat to coordinate all aspects of the project review.[200] The oral hearing for the applications has concluded and a decision is pending.

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193 Letter from Max Ruelokke, Chairman & CEO, CNLOPB, to Kathy Dunderdale, MHA, Minister of Natural Resources, Government of Newfoundland and Labrador (31 January 2007).

194 CNLOPB, News Release, "Opportunity For Comment White Rose Production Volume Increase Development Plan Amendment" (15 December 2006).

195 CNLOPB, Decision 2001.01: *Application for Approval, White Rose Canada-Newfoundland Benefits Plan White Rose Development Plan* (26 November 2001).

196 Husky Energy, *White Rose Development Plan Amendment Production Volume Increase*, Husky Document No. WR-DVG-RP-0007 (September 2006) at 7-8.

197 CNLOPB, News Release "Deep Panuke Public Review Launched" (9 November 2006), online: CNSOPB <http://www.cnsopb.ns.ca/whatsnew/pdf/release_nov9_06.pdf>.

198 EnCana Corporation, *Deep Panuke Offshore Gas Development Project Summary Volume 1* (November 2006), online: CNSOPB <http://www.cnsopb.ns.ca/whatsnew/pdf/Volume_1_Project_Summary.pdf> at 1-1, 1-5, 2-3.

199 EnCana Corporation, *Deep Panuke Offshore Gas Development Application to National Energy Board for a Certificate of Public Convenience and Necessity* (November 2006), online: CNSOPB <http://www.cnsopb.ns.ca/whatsnew/pdf/NEB_Pipeline_Application.pdf> at A-2.

200 *Supra* note 197. See also Deep Panuke Coordinated Public Review Secretariat, online: Secretariat <http://www.deeppanukereview.ca/>.

4. APPEAL OR REVIEW OF OFFSHORE PETROLEUM BOARD DECISIONS

a. *Ruelokke v. Newfoundland & Labrador (Minister of Natural Resources)*[201]

The applicant, Ruelokke, who was selected to be the Chair and Chief Executive Officer (CEO) of the CNLOPB, brought an application seeking an order in the nature of mandamus requiring the provincial (Newfoundland and Labrador) Minister to appoint him Chair and CEO of the CNLOPB under the *NFLD Accord Acts*.[202] Under the *NFLD Accord Acts* federal and provincial Ministers of Natural Resources are to jointly appoint the Chair and CEO of the CNLOPB. However, the Ministers were unable to agree as to the appropriate candidate and consequently the federal Minister gave notice to the provincial Minister that it was triggering the mandatory appointment provisions in the *NFLD Accord Acts*. As a result, both Ministers agreed to appoint a panel to select both a Chair and CEO and the panel ultimately selected the applicant. Subsequently, the provincial Minister refused to appoint the applicant to the position of Chair and in doing so relied on the selection panel's unauthorized advice that the Chair and CEO positions be separated.

In granting a declaration, not an order, that the applicant had been the *de facto* Chair and CEO of the CNLOPB, the Court found that once the selection panel had made its selection to fill the Chair and CEO position, the provincial Minister was bound to that selection. The Court also found that in relying on the panel's unauthorized advice to separate the Chair and CEO position in the hope of having its own preferred candidate appointed as Chair, the provincial Minister was attempting to do an "end run" around the legislated selection process and that it also attempted to delay and frustrate the appointment of the applicant in the hope that it could persuade the federal Minister to appoint the provincial Minister's preferred candidate.[203] Finally, the Court awarded the applicant solicitor-client costs on the basis that the provincial Minister's conduct was callous and reprehensible and deserving of reproof and rebuke.

b. *Polaris Resources Ltd. v. Canada-Newfoundland & Labrador Offshore Petroleum Board*[204]

In January 2001, the applicant, Polaris Resources Ltd., responded to a call for bids for exploration licences and was subsequently issued three exploration licences by the CNLOPB, each of which required that an exploratory well be drilled within five years of the licence being issued otherwise the licensed rights would pass back to the Crown. Under the licences the CNLOPB had discretion to extend the five year period if it determined that: (i) the failure to drill the requisite exploratory well was for reasons beyond the reasonable control of the licence holder; and (ii) the interest holder continues to diligently pursue a remedy for such situation. In October 2005, in the absence of an established Newfoundland and Labrador royalty regime, the applicant sought an extension to the licences from the CNLOPB on the basis that: (i) a royalty regime was a necessary component permitting any smaller exploration

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201 2006 NLTD 127, 258 Nfld. & P.E.I.R. 308.

202 *Supra* note 173, ss. 12, 24 of each *Act*.

203 *Supra* note 201 at para. 29.

204 2006 NLTD 143, 260 Nfld. & P.E.I.R. 244.

company like the applicant to finance an exploration well; and (ii) the applicant, in bidding on the licences, had relied on representations made by the Government of Newfoundland and Labrador that a natural gas royalty regime was forthcoming in the near future. By way of two letters, the CNLOPB rejected the applicant's request on the basis that it was not in the public interest to grant an extension.[205] Subsequently, the applicant brought an application for judicial review on the basis that the CNLOPB, in issuing the letter decisions, breached its right to procedural fairness since the decisions failed to provide adequate reasons.

The Court, after reviewing various authorities, concluded that the CNLOPB did fail to provide adequate reasons since the letters did not reference the two factors contained in the licences, nor did they contain any analysis of those factors that the CNLOPB was obligated to consider in determining if the licences should be extended. The Court also concluded it did not have the authority to extend the licences and remitted the matter to the CNLOPB for further consideration and decision and the rendering of adequate reasons.[206] Subsequently, the CNLOPB did reconsider the matter and ultimately did not extend the exploration licences.[207]

In reaching its decision, the Court went on, in *obiter dicta*, to comment on the CNLOPB "reasons" submitted in the CNLOPB's submissions before the Court. In doing so, the Court indicated that the CNLOPB call for bids, to which the applicant had responded, contained no indication that the applicant's obligations under the licences to drill an exploratory well within five years was being issued contingent on the establishment of a natural gas royalty regime or on obtaining financing. The Court stated that to grant an extension on this basis would be improper as it would amount to changing "the rules of the game" and would destroy the fairness and balance of the bidding process, effectively rendering administration of the licences ineffective.[208] The Court stated that the intention and design of the bidding and licensing process was to promote exploration and ultimate development at the earliest possible time. Additionally, the Court indicated that when assessing whether to grant or refuse a licence extension it is only physical or technical matters that prevent the drilling of an exploratory well that should be considered, since to do otherwise would undermine future bidding processes:

> Waiving compliance with the licence would have a considerable negative effect upon the uniformity of future bidding processes. It would expose the bidding process to excessive and protracted negotiation of the terms of individual licenses. Even though not stated in Clause 11 of the Licences, I am satisfied that the failure to drill an exploration well for reasons beyond the reasonable control of the interest owner are confined to physical or technical matters which would have prevented or delayed the drilling of the well and that this section of the Licences is not intended to deal with the financial capacity of a licence holder to fund its exploration.[209]

Finally, the Court commented on the CNLOPB's jurisdiction and discretion to amend exploration licences stating:

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205 *Ibid.* at paras. 3-11.
206 *Ibid.* at paras. 18-19.
207 In March 2007, CNLOPB staff confirmed the CNLOPB's decision was not public.
208 *Supra* note 204 at para. 22.
209 *Ibid.*

> [S]ince agreement by the Board is required to such an amendment, the Board is afforded the widest possible latitude to determine whether a requested amendment should be made. I am satisfied that the Board's discretion in this regard is limited only by the requirement that it not act in bad faith or for an improper purpose.[210]

c. *Hibernia Management & Development v. Canada-Newfoundland Offshore Petroleum Board*[211]

On 5 November 2004, the CNLOPB established Guidelines for Research and Development Expenditures (R&D Guidelines) which were to apply to all existing and future offshore petroleum projects under the *NFLD Accord Acts*. The R&D Guidelines established expenditure obligations for research and development which would form part of Benefit Plans prepared by project operators. Subsequently, both Hibernia Management & Development Co. and PetroCanada, who each operate existing approved offshore projects, brought a joint application seeking judicial review of the CNLOPB's implementation of the R&D Guidelines in relation to their respective previously approved Benefit Plans. The applicants took the position that the CNLOPB had no authority, as it was *functus officio*, to impose the R&D Guidelines on their respective projects as the CNLOPB had already approved their respective Benefit and Development Plans. Additionally, the applicants submitted that they had acquired vested rights under their previous approvals issued under the *NFLD Accord Acts* and the R&D Guidelines would deprive them of these rights. Finally, the applicants took the position that the CNLOPB exceeded its jurisdiction under the *NFLD Accord Acts* to implement the R&D Guidelines, and more particularly with a research and development fund where unexpended portions of expenditures under the R&D Guidelines would be placed.

The Court denied the application. In doing so, the Court reviewed the pertinent provisions in the *NFLD Accord Acts* as well as each of the previous approvals of the applicants' Benefit Plans and concluded that the CNLOPB was not *functus officio* as the CNLOPB, in establishing the R&D Guidelines, was exercising continuing powers to monitor and assess the appropriateness of the research and development expenditures of the applicants throughout the life of the applicants' projects. In reaching this decision, the Court noted that each of the applicant's previously approved Benefit Plans took the approach of setting out broad principles and general commitments in relation to research and development and that the plans had not set out any specific monetary commitments. The Court found that the applicants' Benefit Plans specifically contemplated that the objectives and monitoring practices of the CNLOPB would be implemented on a regular basis over the duration of the projects. Further, the Court found that the CNLOPB's approvals of the applicants' Benefit Plans contemplated reporting and monitoring, in one instance it was a condition of the approval, to ensure research and development objectives were achieved. In this regard, the Court found that the applicants, in accepting the CNLOPB's previous approvals of their respective Benefit Plans, accepted that the CNLOPB had an ongoing obligation to assess and monitor the appropriateness of expenditures on research and development, and education and training, and as such, the applicants could not now deny the CNLOPB's authority to

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[210] *Ibid.* at para. 23.
[211] 2007 NLTD 14, 263 Nfld. & P.E.I.R. 40.

implement the R&D Guidelines. For similar reasons, the Court found that the R&D Guidelines did not interfere with the vested rights of the applicants.[212] Finally, in considering whether the CNLOPB exceeded its jurisdiction by implementing the R&D Guidelines and the research and development fund, the Court concluded that the CNLOPB acted reasonably in developing and implementing the R&D Guidelines and found that the research and development fund was simply an enforcement mechanism that itself was administrative in nature and hence squarely within the CNLOPB's jurisdiction.

E. ONTARIO ENERGY BOARD

The Ontario Energy Board (OEB) was established and enabled in 1960 under the *Ontario Energy Board Act*[213] and has delegated authority under other Ontario Acts.[214] The OEB regulates various aspects of energy utilities within Ontario, including: construction, operation and safety of provincial pipelines, natural gas storage facilities, and power lines; rates charged by natural gas utilities to transport, store, and distribute natural gas; and the rate charged to distribute electricity.[215] The OEB may review and vary its decisions and any appeal of an OEB decision goes to the Ontario Superior Court of Justice.[216] Select OEB decisions of significance to oil and gas lawyers during the May 2006 to April 2007 period are discussed below.

1. EB-2005-0551: NATURAL GAS ELECTRICITY INTERFACE REVIEW[217]

In 2003, the OEB initiated a review of natural gas regulation in Ontario in order to address the evolving natural gas market. The review was directed at infrastructure requirements to address changing natural gas flow patterns due to anticipated flat to decreasing natural gas supply, increasing reliance on non-conventional supply, and expansion of gas fired power generation. As a result of the review in 2004, the OEB initiated the Natural Gas Electricity Interface Review (NGEIR) to examine the regulatory treatment of natural gas infrastructure and services. In November 2005, the OEB initiated a generic hearing (the NGEIR Proceeding) initially to consider four issues, three of which were later substantively addressed. The remaining issue concerned s. 29 of the *OEB Act*, which would permit the OEB to refrain, in whole or in part, from regulating gas storage rates if it determines that there is sufficient competition in natural gas storage to protect the public interest.

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212 *Ibid.* at paras. 52-53. At paras. 58-74, the Court also rejected arguments made by the applicants in relation to various intergovernmental agreements specific to the applicants' individual projects as well as an argument relating to the legislative drafting principle of *ejusdem generis*.

213 S.O. 1998, c. 15, Sch. B [*OEB Act*].

214 Including, but not limited to: *Electricity Act, 1998*, S.O. 1998, c. 15, Sch. A; *Municipal Franchises Act*, R.S.O. 1990, c. M.55.

215 See the OEB website, online: OEB <http://www.oeb.gov.on.ca>.

216 OEB, *Rules of Practice and Procedure* (1997), online: OEB <http://www.oeb.gov.on.ca/documents/rulesofpractice_final_091002.pdf> at Part VII, s. 42; *OEB Act*, *supra* note 213, s. 33.

217 OEB, Oral Decision, OEB File No. EB-2005-0551 (7 November 2006), online: OEB <http://www.oeb.gov.on.ca/documents/cases/EB-2005-0551/Decision_Orders/dec_reasons_071106.pdf>. As of the date of this article, the OEB is currently considering three motions for review of this decision (OEB File Nos. EB-2006-0322, EB-2006-0338, and EB-2006-0340).

With input from various consumer and industry groups, OEB regulated companies such as Union Gas Limited (Union Gas) and Enbridge Gas Distribution Inc. (EGDI), federally regulated gas transmission providers such as TCPL, various natural gas fired power generators, and various gas suppliers and marketers, the OEB ultimately determined that it should refrain (forbear) in part from regulating natural gas storage rates and contracts.

The OEB found that although Union Gas and EGDI own substantively all of the gas storage in Ontario, they compete in a broader secondary market that extends into parts of the United States and is served by various pipeline and storage facilities and other mechanisms such as swaps, exchanges, and park and loan services that provided alternatives to storage and increased liquidity in the market. Consequently, neither Union Gas nor EGDI had market power and the market was workably competitive.

The OEB went on to consider, as required by s. 29 of the *OEB Act*, whether competition was sufficient to protect the public interest having regard to the legislative objectives most relevant to the case, including: facilitating competition in sale of gas to users; protecting consumers' interests with respect to prices, reliability, and quality of gas service; and facilitation of rational development and safe operation of gas storage. The OEB went on to conclude that it was in the public interest to forbear from regulating certain gas storage rates and contracts in some instances but not in others.

In-franchise[218] customers of both Union Gas and EGDI would not benefit from competition and have no direct access to storage alternatives. Consequently in-franchise customers would continue to be charged cost of service based rates for gas storage.

Market-based prices would be permitted for storage services offered by: (i) new third-party (non-utility) storage providers and Ontario consumers would not bear any risk associated with new storage developments; (ii) utility storage providers, subject to some transitional provisions, when providing ex-franchise storage service to other distribution utilities; (iii) new utility storage, including new storage services developed specifically for the high deliverability market created by gas fired power generators; and (iv) utility storage provided to ex-franchise customers.

Finally, the margins or premiums over cost of service that Union and EGDI were anticipated to earn for unregulated storage services provided through utility assets surplus to in-franchise needs, are to be shared with in-franchise customers.

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218 Historically, gas storage in Ontario was subject to cost-based and market-based rates. In-franchise customers (those receiving transmission, distribution, and distribution services) were protected by full cost of service rate regulation, while ex-franchise customers (storage customers who are not also distribution customers) were subject to market rates in excess of cost of service to an OEB-approved maximum. The margins associated with market-based rates were shared between the utilities and in-franchise customers generally on a 25/75 basis respectively. See OEB, Decision with Reasons, OEB File No. EB-20050-0551 (7 November 2006), online: OEB <http://www.oeb.gov.on.ca/documents/cases/EB-2005-0551/Decision_Orders/dec_reasons_071106.pdf>.

2. EB-2005-0211/EB-2006-0081: UNION GAS LIMITED DISPOSITION OF PROCEEDS FROM THE SALE OF CAPITAL ASSETS[219]

In 2005, Union Gas sought OEB approval, under s. 36 of the *OEB Act* which dealt with the setting of rates for the sale, transmission, distribution or storage of gas, for the disposition of funds held in certain deferral accounts. The funds included the proceeds from the sale of cushion gas used in the storage operations of Union Gas, which were historically treated as an undepreciated capital asset. Union Gas sought to retain the entire cushion gas proceeds on the basis that sale of the cushion gas did not harm or prejudice its customers. Since the *ATCO* case,[220] which dealt with similar subject matter, was currently before the Supreme Court of Canada at the time Union's application was before the OEB, the OEB decided to defer its consideration of the disposition of the cushion gas proceeds until following the Supreme Court's decision in *ATCO*.

After the Supreme Court's decision in *ATCO*, the OEB issued Decision and Order EB-2005-0211[221] in which it distinguished the Court's decision in *ATCO* on the basis of differences in the legislative regimes and factual circumstances, and found that it had the jurisdiction, under its broad rate-making authority in s. 36 of the *OEB Act*, to approve the sale of gas and to determine how the consequences of the sale were to be considered in the process of setting Union Gas's rates. At the same time, the OEB summarily dismissed issues relating to both retroactive rate making due to the delay in waiting for the Supreme Court's decision and allegations of a reasonable apprehension of bias due to the OEB's participation in the *ATCO* case before the Supreme Court. In the result, the OEB decided to hold a future proceeding to determine whether there were any consequences from the sale of cushion gas and how those should be considered in setting Union Gas's rates. Subsequently, Union Gas filed a motion for clarification of the Decision and Order EB-2005-0211 and filed an application for judicial review.

The OEB, on its own motion, decided to review the panel's Decision and Order EB-2005-0211 and to concurrently consider a similar decision relating to the apportionment of assets relating to EGDI. The result was the combined Decision and Order EB-2005-0211/EB-2006-0081.[222] In this combined decision, the OEB confirms it has jurisdiction to consider how to handle the proceeds of sale of utility capital assets and does so again by distinguishing the Supreme Court's decision in *ATCO* on the basis of differences between the Alberta legislation considered by the Supreme Court and the *OEB Act*. Specifically, the OEB takes the position that unlike the legislation under consideration in *ATCO*, which contained a specific legislative provision enabling the AEUB to approve the disposition of capital assets but lacked any express provision to deal with the proceeds, the *OEB Act* is silent and instead, the OEB's jurisdiction in relation to the sale of cushion gas by Union Gas arises in the context of its broad rate-making power under s. 36 of the *OEB Act*.

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219 OEB, Decision and Order, OEB File Nos. EB-2005-0211, EB-2006-0081 (30 January 2007), online: OEB <http://www.oeb.gov.on.ca/documents/cases/EB-2005-0211/decision_order_uniongas_cushioned gas_appendices_20070130.pdf > [note that this is a combined decision]. Notice of Appeal filed with the Ontario Superior Court of Justice, Court File No. 379/06.

220 *Supra* note 11.

221 *Supra* note 219 at App. A.

222 See *supra* note 219.

The OEB went on to state that its very broad rate-making authority under s. 36 included the authority to encourage or discourage utility behaviour that is in the public interest via incentives and disincentives and this authority could be exercised, in appropriate circumstances, where a utility has sold an asset.

In the result, the OEB again ordered that the original panel consider the extent, if any, to which the proceeds of the sale of cushion gas is to be allocated as between ratepayers and Union Gas.

F. BRITISH COLUMBIA UTILITIES COMMISSION

The British Columbia Utility Commission (BCUC) is enabled under the *Utilities Commission Act*[223] and has delegated authority under other British Columbia legislation.[224] The BCUC regulates various aspects of energy utilities within British Columbia, including construction of provincial pipelines and power lines, the rates charged by natural gas and electrical utilities, and certain aspects of non-utility pipeline operation.[225] The BCUC may review and vary its decisions and any appeal of a BCUC decision lies with the British Columbia Court of Appeal.[226] Select BCUC decisions of significance to oil and gas lawyers during the May 2006 to April 2007 period are discussed below.

1. ORDER G-15-07: MARAUDER RESOURCES WEST COAST INC. COMMON CARRIER AND PROCESSOR ORDERS[227]

In June 2006, Marauder Resources West Coast Inc. (Marauder) applied for an order declaring both Canadian Natural Resources Ltd. (CNRL) and Pioneer Natural Resources Canada Inc. (Pioneer) to be common carriers and processors of natural gas produced from the Velma Bluesky pool (the Pool). In addition to seeking common carrier and processor orders, Marauder also sought, to the extent necessary, that the BCUC require the sharing or rateable take of production from the Pool. Marauder also sought the effective date of such orders to be the date of application. Subsequent to filing its common carrier and processor applications, Marauder made an application to the Ministry of Energy, Mines and Petroleum Resources (MEMPR) for a reserve allocation order relating to the Pool.

The Pool contained three wells, two owned by Marauder and one owned by CNRL. At the time of the applications, only the CNRL well was producing and Marauder sought access, after failed commercial negotiations, via common carrier and processor orders to two separate pipelines and gas plants, each operated by CNRL and Pioneer respectively. The CNRL facilities processed gas from the CNRL well in the Pool while the Pioneer facilities did not process any gas from the Pool. Marauder was of the view that CNRL had excess

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223 R.S.B.C. 1996, c. 473.

224 Including, but not limited to, the *Pipeline Act*, R.S.B.C. 1996, c. 364, as amended.

225 See the BCUC website, online: BCUC <http://www.bcuc.com>. All decisions and orders issued by the BCUC may be accessed via this website.

226 *Supra* note 223, ss. 99, 101.

227 BCUC, Decision and Order G-15-07: *In the Matter of Marauder Resources West Coast Inc., An Application for Common Carrier/Common Processor Orders to Canadian Natural Resources Ltd. and Pioneer Natural Resources Canada Inc., Velma Field, Bluesky Pool* (14 February 2007).

capacity to handle Marauder's gas production from the Pool. In the alternative, if CNRL did not have sufficient pipeline or processing capacity then Marauder instead sought access to either: (i) the CNRL facilities on the basis that Marauder and CNRL would share the capacity and the production from their combined wells in the Pool based on their respective proportionate share, or rateable take entitlement, of the Pool on a reserves basis; or (ii) to the Pioneer facilities on the basis that Marauder obtain sufficient capacity to permit it to produce its proportionate share of the Pool and in the event that those facilities did not have sufficient capacity to permit Marauder to produce its share of the Pool, that CNRL be required to reduce production from its well on a rateable basis in keeping with its proportionate share of the Pool.

The BCUC, in considering its first ever common carrier and common processor applications,[228] adopted the AEUB's common carrier and processor criteria outlined in the AEUB's Directive 065[229] and also considered criteria relating to competitive drainage, surplus capacity, quality of gas, and proliferation of facilities. In reaching its decision, the BCUC highlighted that no one criterion is determinative with respect to common carrier and processor orders and that an exercise of discretion to vary the weight of the various criterion will occur based on the circumstances of each case.

Although certain of the criteria considered by the BCUC were met,[230] the BCUC denied both applications on the basis that Marauder failed to make substantial efforts to negotiate a resolution with Pioneer or CNRL. Specifically, the BCUC noted that Marauder constructed a pipeline in advance of Pioneer agreeing to permit Marauder access to its facilities and found as fact that Marauder was not particularly interested in negotiating reasonable arrangements with CNRL, but instead had a strategy to use the common carrier and processor remedies. Additionally, the BCUC found that Marauder's intention was to gain a competitive advantage over CNRL in order to out-produce CNRL in the Pool. Although the CNRL option may have been the most practical way of transporting and processing Marauder's gas, Marauder failed to demonstrate that the applied for common carrier and processor operations were the only feasible way. Further, the BCUC noted that the rate or the amount of return Marauder may have wanted to earn on its investment was not a determining factor.

Additionally, although the BCUC found that Marauder was suffering competitive drainage by CNRL, it also found that it was not inequitable drainage as Marauder could have alleviated the drainage by accessing other transportation and processing options. Having found that both CNRL and Pioneer's pipeline compression was at capacity, the BCUC stated that it would not compel an owner subject to a common processor or carrier order to invest in additional equipment not otherwise required to transport its own capacity to transport a third party's capacity. Similarly, the BCUC stated it would not require an owner subject to such orders to install sweetening or refrigeration facilities it would not otherwise require to process its own gas in order to accommodate a third party. Having denied both of Marauder's

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228 The BCUC had only previously considered common purchaser applications, the most recent being 1985.

229 AEUB, Directive 065: *Resources Applications for Conventional Oil and Gas Reservoirs* (3 July 2007) [Directive 065].

230 Including demonstrated producible reserves available for transportation through existing pipelines and a reasonable expectation of a market for the subject gas.

applications, the BCUC did not have to consider whether it had jurisdiction to allocate reserves in the Pool.

III. LEGISLATIVE DEVELOPMENTS[231]

A. FEDERAL

1. NEB LEGISLATION AND ASSOCIATED REGULATIONS[232]

There have been no legislative developments in relation to the NEB's enabling legislation and only non-substantive amendments to related delegating legislation since the last Regulatory Update.[233] Recent revisions to the *Onshore Pipeline Regulations, 1999*[234] include the repeal of s. 7 of the *Regulations* relating to certain instances when the NEB may have required submission of designs, specifications, programs, manuals, procedures, and plans (collectively, Designs and Procedures). Related amendments to other sections within the regulations that had referenced s. 7 were made to clarify when Designs and Procedures must be submitted to the NEB for approval.

B. ALBERTA

1. *ALBERTA ENERGY AND UTILITY BOARD RULES OF PRACTICE*

The *Alberta Energy and Utility Board Rules of Practice*[235] enacted under the *AEUB Act*,[236] were amended by Alta. Reg. 154/2006. The amendments include, among other things, amendments regarding submissions, questions of constitutional law, applications for review, and costs. In particular, s. 9.1 of the *Rules* now provides for the submission of objections prior to the filing of an energy development application provided that the objection is served on the proponent of the proposed application. Section 23.1 of the *Rules* also states that a person who intends to raise a question of constitutional law before the AEUB must give notice in accordance with s. 12 of the *Administrative Procedures and Jurisdiction Act*.[237] The requirements for review requests under s. 40 of the *ERCA*[238] were also clarified by changes to s. 46 of the *Rules*.

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[231] In preparing this article, only those legislative amendments relating to enabling and delegating legislation of select boards and administrative tribunals discussed herein were reviewed.

[232] Table of Public Statutes (1907 to 31 August 2007), C. Gaz. 2007.III. (Vol. 29, No. 2. c. 5-14); Associated Regulations — Consolidated Index of Statutory Instruments (1 January 1955 to 31 December 2006); C. Gaz. 2007.II. (Vol. 141, No. 6).

[233] See Paul Jeffrey & Gloria Chao, "Recent Regulatory and Legislative Developments of Interest to Oil and Gas Lawyers" (2007) 44 Alta. L. Rev. 619.

[234] S.O.R./99-294, as am. by S.O.R./2007-50.

[235] Alta. Reg. 101/2001 [*Rules*].

[236] *Supra* note 49.

[237] R.S.A. 2000, c. A-3.

[238] *Supra* note 58.

2. *ADMINISTRATION FEES REGULATION*

The *Administration Fees Regulation*[239] enacted under the *AEUB Act* was amended by Alta. Reg. 140/2006.

3. *GAS UTILITIES EXEMPTION REGULATION*

The *Gas Utilities Exemption Regulation*[240] enacted under the *GUA*[241] was amended by Alta. Reg. 306/2006.

4. *OIL AND GAS CONSERVATION REGULATIONS*

The *OGCR*[242] enacted under the *OGCA*[243] were amended by Alta. Reg. 40/2006, Alta. Reg. 142/2006, Alta. Reg. 153/2006, Alta. Reg. 269/2006, and Alta. Reg. 12/2007. Amendments include, among other things, the implementation of an amendment to facilitate the creation of a regional area for higher baseline well spacing as part of the AEUB's *Well Spacing Initiative*.[244] The AEUB's *Well Spacing Initiative* applies to the region of Alberta east of the 5th Meridian and south of Township 53, as shown on Schedule 13A of the *OGCR*. Specifically, baseline densities have been increased as follows: (i) gas pool — 2 wells per pool per section in the Manville Formation, 4 wells per pool per section in formations above the Manville; and (ii) oil pool — 2 wells per pool per quarter section in the Manville formation. Below the Manville formation, the well density of one well per pool per section for gas and one well per pool per quarter section for oil is maintained. Also, above the Manville formation, the well density of one well per pool per quarter section for oil is maintained. Target areas for the region set out in Schedule 13A of the *OGCR* have also been revised.

5. *ORPHAN FUND DELEGATED ADMINISTRATION REGULATION*

The *Orphan Fund Delegated Administration Regulation*,[245] enacted under the *OGCA*, was amended by Alta. Regs. 67/2006 and 35/2007.

6. *PUBLIC UTILITIES DESIGNATION REGULATION*

The *Public Utilities Designation Regulation*,[246] enacted under the *Public Utilities Board Act*[247] repealed Alta. Reg. 131/2000 and was amended by Alta. Reg. 10/2007. The *PUDR* lists the owners of public utilities subject to ss. 101, 102, and 109 of the *PUBA*. Sections 101,

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239 Alta. Reg. 135/2002.
240 Alta. Reg. 53/1999.
241 *Supra* note 12.
242 *Supra* note 113.
243 *Supra* note 76.
244 See Alta Reg. 153/2006.
245 Alta. Reg. 45/2001.
246 Alta. Reg. 194/2006 [*PUDR*].
247 R.S.A. 2000, c. P-45 [*PUBA*].

102, and 109 identify transactions by designated owners of public utilities which require prior approval of the AEUB.

7. *NATURAL GAS PRICE PROTECTION REGULATION*

The *Natural Gas Price Protection Regulation*[248] was amended by Alta Reg. 196/2006.

8. *NATURAL GAS ROYALTY REGULATION, 2002*

The *Natural Gas Royalty Regulation, 2002*[249] was amended by Alta. Reg. 208/2006.

9. *MINES AND MINERALS ACT*

Sections 3(2), 3(3), 3(5), and 3(6) of the *Administrative Penalties and Related Matters Statutes Amendment Act, 2002*[250] were proclaimed into force effective 8 November 2006. The provisions amend and repeal certain sections of the *Mines and Minerals Act*,[251] and deal with offences, vicarious responsibility, and powers of the Minister.

10. *EXPLORATION REGULATION*

The *Exploration Regulation*[252] enacted under the *Forests Act*,[253] the *Mines and Minerals Act*,[254] the *Public Highways Development Act*,[255] and the *Public Lands Act*[256] repealed Alta. Regs. 32/90 and 214/98 and was amended by Alta. Reg. 35/2007.

C. BRITISH COLUMBIA

1. BCUC LEGISLATION AND ASSOCIATED REGULATIONS[257]

In May 2006, the *Utilities Commission Act*[258] was amended as it relates to its interaction with the *Local Government Grants Act*,[259] the *Community Charter*,[260] and authorizations issued by the BCUC.[261] Additionally, an associated regulation, the *Public Utility Regulation*,[262] came into force in June 2006. No other substantive amendments to the enabling or delegating legislation of the BCUC have occurred since the last regulatory update.

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248 Alta. Reg. 157/2001.
249 Alta. Reg. 220/2002.
250 S.A. 2002, c. 4.
251 *Supra* note 88.
252 Alta. Reg. 284/2006.
253 R.S.A. 2000, c. F-22.
254 R.S.A. 2000, c. M-17.
255 R.S.A. 2000, c. P-38.
256 R.S.A. 2000, c. P-40.
257 British Columbia "Table of Legislative Changes" and "Point in Time Act Content" to December 2006.
258 *Supra* note 223.
259 R.S.B.C. 1996, c. 275.
260 S.B.C. 2003, c. 26.
261 *Miscellaneous Statutes Amendment Act (No. 2) 2006*, S.B.C. 2006, c. 24, s. 53.
262 B.C. Reg. 174/2006.

IV. DEVELOPMENTS IN POLICY, DIRECTIVES, AND GUIDELINES

A. NATIONAL ENERGY BOARD

1. NATIONAL ENERGY BOARD *FILING MANUAL*[263]

The NEB's *Filing Manual*, which was last issued in April 2004, was revised in April 2006.[264] The revisions are minor in nature and relate to both the NEB's most recent s. 58 Streamlining Order (Order XG/XO-100-2005), which updates the list of projects eligible for streamlining,[265] and guidance on scoping and analysis of cumulative effects, specifically guidance on what other projects should be included in any such assessment.[266]

2. *NATIONAL ENERGY BOARD RULES OF PRACTICE AND PROCEDURE*[267]

In February 2007, the NEB announced that it was considering amending the *National Energy Board Rules of Practice and Procedure* (the NEB Rules) and requested comments from counsel who regularly appear before the NEB.[268] Areas of the NEB Rules that that have been identified as possibly requiring amendment include: filing and service, reviews, interventions, oral statements, alternatives for public participation in proceedings, and motion procedure.

B. ALBERTA ENERGY AND UTILITIES BOARD

1. AEUB DIRECTIVE 038: *NOISE CONTROL*[269]

In February 2007, the AEUB revised Directive 038, which sets out the requirements for noise control as they apply to all operations and facilities under the AEUB's jurisdiction.[270] The revised edition of Directive 038 replaces Guide 38 as well as Interim Directive ID 99-08. The requirements deal with "environmental noise" as opposed to health-related impacts associated with noise.

Section 1.3 of Directive 038 provides a summary of the significant revisions which include, among other things, numerous additions and modifications of technical and procedural requirements.[271] In particular, in relation to permissible sound levels (PSLs), s. 2 of Directive 038 provides that "[n]ew facilities must not exceed a sound level of 40 dBA Leq (nighttime) at 1.5 km from the facility fence line if there are no closer dwellings."[272] In

263 NEB, *Filing Manual* (April 2004), online: NEB <http://www.neb.gc.ca/clf-nsi/rpblctn/ctsndrgltn/flngmnl/fmflngmnl-eng.pdf>.
264 *Ibid.* at 4A-1-4A-10, 4A-41-4A-46.
265 *Ibid.* at 4A-2, 4A-4-4A-10.
266 *Ibid.* at 4A-42.
267 *National Energy Board Rules of Practice and Procedure, 1995*, S.O.R./95-208.
268 NEB, Letter: "Amendment to National Energy Board Rules of Practice and Procedure, 1995 ('Rules') Request for Comments" (14 February 2007).
269 (16 February 2007) [Directive 038].
270 See *ibid.*, s. 1.4, which sets out the scope of Directive 038.
271 *Ibid.*
272 *Ibid.*, s. 1.3.

addition, in the context of noise impact assessments, s. 3.3 of Directive 038 provides that "[t]he predicted noise levels (sound pressure levels [SPLs]) of the facility plus the ambient sound levels must be compared to the PSL."[273]

2. AEUB DIRECTIVE 060: *UPSTREAM PETROLEUM INDUSTRY FLARING, INCINERATING, AND VENTING*[274]

Directive 060, which provides the regulatory requirements for flaring, incinerating, and venting for the upstream petroleum industry, was revised in November 2006. Appendix 1 of Directive 060 sets out the major revisions. Among other things, significant changes include the development of time limits for well test flaring and venting as well as the requirement that programs be developed and implemented to address fugitive emissions.[275] In particular, s. 3.2 of Directive 060 provides for well test flaring and venting time limits specific to each type of well. For instance, for conventional oil and gas wells, the time limit is 72 hours.[276]

3. AEUB DIRECTIVE 041: *ADOPTION OF CSA Z662-03, ANNEX N, AS MANDATORY*[277]

In December 2005, the Canadian Standards Association (CSA) published supplement No. 1 to CSA Z662-03, Oil and Gas Pipeline Systems (CSA Z662), which consists of a new Annex M: Sour Service Pipelines, which is mandatory, and Annex N: Guidelines for Pipeline Integrity Management Programs, which is not mandatory.

CSA Z662 is incorporated by reference into the *Pipeline Regulation*[278] under s. 9(2). Accordingly, since Annex M is mandatory and CSA Z662 is incorporated by reference into the *Pipeline Regulation*, pipeline licensees are required to implement the requirements set out in Annex M.

In July 2006, the AEUB issued Directive 041, which makes Annex N mandatory and requires that all pipeline licensees must develop and implement integrity management programs in accordance with Annex N of CSA Z662. Annex N "provides an approach for ensuring that pipelines are capable of transporting product safely, without short-term or long-term negative effects on public safety or the environment."[279]

4. AEUB DRAFT DIRECTIVE 071: *EMERGENCY PREPAREDNESS AND RESPONSE REQUIREMENTS FOR THE PETROLEUM INDUSTRY*[280]

In December 2006, the AEUB released Draft Directive 071 for stakeholder review and comment. Directive 071 provides the regulatory requirements concerning emergency

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273 *Ibid.*
274 (16 November 2006) [Directive 060].
275 *Ibid.*, s. 1.3.
276 *Ibid.*, s. 3.2.
277 (18 July 2006) [Directive 041].
278 Alta. Reg. 91/2005.
279 *Supra* note 277 at 1.
280 (December 2006) [Draft Directive 071].

preparedness and response, including emergency response plans (ERP). A significant change proposed by the AEUB involves the requirement to use a new computer software program — EUBH2S — for calculating emergency planning zones (EPZ) for sour wells, pipelines, and facilities.[281] In addition, Draft Directive 071 states, among other things, that the AEUB will no longer consider reduced EPZ requests and licensees will be required to submit their Corporate-Level ERPs to the AEUB for registration and ensure that a 24-hour emergency contact number is included in the emergency response plan.[282] Table 1 of Draft Directive 071 provides a summary of all of the proposed new requirements.

5. AEUB BULLETIN 2006-28: "COMMINGLING OF PRODUCTION"[283]

In Bulletin 2006-28, the AEUB acknowledged that "[t]he commingling of production from multiple pools in the wellbore is a longstanding practice in Alberta" and "that commingling maximizes conservation and is necessary for the economic and orderly development of lower productivity resources."[284] The AEUB further stated that in the vast majority of cases, experience has proved that commingling in the wellbore does not lead to additional operational or environmental risks. In addition, the AEUB noted that since the development of Alberta's resource base has shifted to lower productivity reservoirs "the need to commingle multiple pools in the wellbore has increased."[285] As such, the AEUB concluded that prior approval to commingle production from two or more pools will no longer be required in all cases. In particular, the AEUB determined that three processes will be available to manage the commingling of production in the wellbore: (i) development entity (DE);[286] (ii) self-declared commingling;[287] and (iii) applications in accordance with Directive 065.

6. AEUB DIRECTIVE 065: *RESOURCE APPLICATIONS FOR CONVENTIONAL OIL AND GAS RESERVOIRS*[288]

The AEUB revised Directive 065 in August 2006 and January 2007. The August 2006 revisions include changes to notification requirements for well spacing applications. In particular, under s. 1.6.4 of Directive 065 notification of well spacing applications must be conducted and the notification period, a minimum of 15 working days, must be completed prior to filing an application with the AEUB. In addition, notification requirements are broadened to include freehold mineral owners whose rights are leased in order to, among other things, provide them with information regarding potential development.[289]

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281 *Ibid.*, s. 3.
282 *Ibid.*, s. 2.
283 AEUB, Bulletin 2006-28: "Changes to the Management of Commingling of Production from Two or More Pools in the Wellbore" (8 August 2006).
284 *Ibid.* at 1.
285 *Ibid.*
286 See *OGCR*, *supra* note 113, s. 3.051(1).
287 *Ibid.*, 3.051(2).
288 (3 July 2007) [Directive 065].
289 *Ibid.* at 1-37.

In January 2007, the AEUB revised Directive 065 with respect to, among other things, applications for common carrier,[290] common purchaser,[291] and common processor[292] declarations. In particular, changes to Directive 065 were implemented to assist industry in applying for the AEUB to set prices or fees under s. 55 of the *OGCA*, which provides the AEUB with the authority to set the price to be paid to the common purchaser for gas, the fee to be paid to the common carrier for the transportation of gas or oil, and the fee to be paid to the common processor for the processing of gas.[293] The revisions to the common carrier and common processor portions of Directive 065 reflect the AEUB's support for setting fees under s. 55 of the *OGCA* using the formula and principles set out in JP-05.[294] For instance, in relation to common carrier applications, Directive 065 provides that if the applicant proposes an alternative method of calculating fees other than the JP-05 formula, it should offer detailed justification as to why the AEUB should not consider the JP-05 formula.[295]

7. AEUB DIRECTIVE 035: *BASELINE WATER WELL TESTING REQUIREMENTS*[296]

Under Directive 035, effective 1 May 2006, an applicant or licensee intending to drill a new well or complete or re-complete wells for the purpose of producing CBM above the base of ground water protection (BGWP) must comply with the Alberta Environment Standard for Baseline Water Well Testing for Coalbed Methane/Natural Gas in Coal Operations (AENV Standard).

As such, for CBM wells above the BGWP licenced on or after 1 May 2006, prior to filing a new well licence application, an applicant must offer to test any active water wells and observation wells within a 600 m radius of the proposed CBM well. If no such wells are identified with the 600 m radius, the applicant must offer to test the nearest water well or observation well within a 600 to 800 m radius. In either case, the applicant must document the process in accordance with the AENV Standard.[297] In addition, if an offer to test is accepted, the applicant must test the water wells and observation wells in accordance with the AENV Standard prior to drilling the CBM well and provide Alberta Environment and

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290 Section 48(1) of the *OGCA*, *supra* note 76, provides for the declaration of a common carrier of oil, gas, or synthetic crude oil. A common carrier order issued by the AEUB allows an applicant to share in the capacity of another party's pipeline.

291 Sections 50(1) and 51(1) of the *OGCA*, *ibid.*, provide for the declaration of a common purchaser of oil and gas. A common purchaser order issued by the AEUB would allow an applicant to share in the gas or oil market obtained by other producers in the pool and thereby obtain its share of production from the pool.

292 Section 53 of the *OGCA*, *ibid.*, provides for the declaration of a common processor of gas. A common processor order issued by the AEUB allows an applicant to share in the capacity of a gas processing plant.

293 See AEUB, Bulletin 2007-02: "Revisions and Additions to Directive 065: Resources Applications for Convention Oil and Gas Reservoirs January 2007 Edition Issued" (26 January 2007).

294 Canadian Association of Petroleum Producers *et al.*, *JP-05: A Recommended Practice for the Negotiation of Processing Fees — Joint Industry Task Force Report* (October 2005), online: Gas Processing Association of Canada <http://www.gpacanada.com/docs/committees/JP-05_final_report (endorsed).pdf>.

295 *Supra* note 288. See also Decision 2006-021, *supra* note 75, which confirms the AEUB's support for the setting of tariffs and fees using the formula and principles set out in JP-05.

296 *Supra* note 71.

297 *Ibid.*, s. 1.

landowners/occupants with copies of the tests within two months of testing.[298] In general, the testing will gather background information on the water well's production capability and water quality.

8. AEUB DIRECTIVE 019: *ERCB COMPLIANCE ASSURANCE - ENFORCEMENT*

Directive 019,[299] which deals with the enforcement aspect of compliance assurance and applies to all AEUB requirements and processes with the exception of utility rate matters, was revised by the AEUB in February 2007. In particular, Table 1: AEUB Enforcement of Low Risk Noncompliance; Table 2: AEUB Enforcement of High Risk Noncompliance; and Section 5, which addresses Enforcement Appeals were amended in response to individual stakeholder feedback received by the AEUB.

C. BRITISH COLUMBIA UTILITIES COMMISSION

1. G-130-06: *RULES FOR NATURAL GAS ENERGY SUPPLY CONTRACTS*[300]

In October 2006, the BCUC revised its Rules for Natural Gas Energy Supply Contracts to address the development of unbundled commodity supply options for commercial and residential natural gas customers in British Columbia, which commenced in November 2007.

[298] *Ibid.*, s. 2.1.1.
[299] (20 February 2007) [Directive 019].
[300] BCUC, Order No. G-130-06: *Rules for Natural Gas Energy Supply Contracts* (26 October 2006).