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

JOHN GRUBER*

This article canvasses significant regulatory and legislative development in oil and gas law during the period April 2004 to March 2005. Selected contributions of courts (the Federal Court of Appeal, Alberta Court of Appeal, and Alberta Court of Queen's Bench), regulatory bodies (the National Energy Board, the Alberta Energy and Utilities Board, and the Alberta Environmental Appeals Board), and legislators (at the federal and provincial levels) are summarized and analyzed, followed by a discussion of policy initiatives. The article deals with a variety of developments, highlighting themes of considerable importance to oil and gas law. These include: the continuing effects of GB 2003-028 on gas/bitumen conservation policy, the consequences of the recent regulatory decisions of the National Energy Board on TransCanada Pipelines Limited tolls on upstream and midstream companies and, more generally, changes to energy legislation in Alberta and British Columbia.

Cet article examine le développement réglementaire et législatif important qui a eu lieu dans le secteur pétrolier entre avril 2004 et mars 2005. Une sélection de contributions de cours (Cour d'appel fédérale, Cour d'appel de l'Alberta et Cour du banc de la reine de l'Alberta), d'organismes de réglementation (Office national de l'énergie, Alberta Energy and Utilities Board et Alberta Environmental Appeals Board), et de législateurs (niveaux fédéral et provinciaux) y est résumée et analysée et suivie d'une discussion sur les initiatives politiques. L'article aborde un certain nombre de développement, soulignant les thèmes d'importance pour le droit dans le domaine du pétrole et du gaz. Ces thèmes incluent les effets continus de GB 2003-028 sur la politique de conservation du gaz/bitume, les conséquences des récentes décisions réglementaires de l'Office national de l'énergie sur les droits de TransCanada Pipelines Limited à l'égard des sociétés d'activités médianes et en amont et, de manière plus générale, les changements aux lois énergétiques en Alberta et en Colombie-Britannique.

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* Thackray Burgess. The author gratefully acknowledges the invaluable assistance of David Farmer, Associate, Thackray Burgess and Katie Slipp, Student-at-law, Thackray Burgess.

I. INTRODUCTION

This article will summarize significant regulatory decisions, legislative amendments, and regulatory policy developments that took place between April 2004 and March 2005. The article will focus on those developments that impact the upstream and midstream oil and gas industry in the Western Canadian Sedimentary Basin. Decisions from the Alberta Energy and Utilities Board, the National Energy Board, and the Alberta Environmental Appeal Board are reviewed in addition to certain regulatory decisions by courts with supervisory jurisdiction.

This article is not intended as a complete summary of the regulatory landscape for the past year. Rather, a smaller number of decisions are focused on and the discussion will attempt to provide some analysis of each decision.

The Alberta Environmental Appeal Board considered an issue of significance to the oil and gas industry, namely the diversion of surface water for the purposes of secondary recovery. As the basin matures and competition for the water resource continues, water management issues that come before the Alberta Environmental Appeal Board will likely increase in scope and importance.

In addition to the normal applications that it is required to deal with, the Alberta Energy and Utilities Board continued to deal with the sequel from General Bulletin 2003-028 with respect to its gas/bitumen conservation policy. The Board's actions in these areas resulted in a number of challenges to both the Alberta Court of Queen's Bench and the Alberta Court of Appeal. In addition to conservation and other technical matters, the Alberta Energy and Utilities Board and reviewing courts have had to address issues related to administrative fairness and the deference granted to the Board in carrying out its conservation mandate. This ongoing process is of tremendous importance to the industry.

The National Energy Board issued a decision that has the potential to impact upstream and midstream companies. This decision respects the TransCanada Pipelines Limited Mainline tolls. The Federal Court of Appeal also had the opportunity to review the National Energy Board's methodology with respect to setting TransCanada Pipelines Limited tolls.

This article will also highlight a number of legislative changes in Alberta, British Columbia, and at the federal level. There have been a number of changes in the energy legislation in these jurisdictions that participants in the oil and gas sector need to be concerned with.

In addition to legislative changes, there have been a number of changes to various National Energy Board policy initiatives. The Alberta Energy and Utilities Board has also amended a number of its policies and procedures, and these changes are of interest to regulatory practitioners.

II. JUDICIAL DECISIONS

A. FEDERAL COURT OF APPEAL

1. *TRANSCANADA PIPELINES LIMITED V. CANADA (NATIONAL ENERGY BOARD)*[1]

Pursuant to s. 22 of the *National Energy Board Act*,[2] TransCanada PipeLines Limited (TCPL) appealed Decision RH-R-1-2002[3] of the National Energy Board (NEB).

This was an appeal with respect to TCPL's Canadian Mainline Natural Gas Transmission System (Canadian Mainline). The NEB considers the Canadian Mainline a major (Group 1) pipeline.

This appeal related to a 1994 hearing conducted by the NEB with respect to certain Group 1 pipelines, including Canadian Mainline. These hearings were conducted in order to fix the cost of capital for those pipelines for the period commencing 1 January 1995, and to establish an automatic mechanism to determine adjustments to the rate of return on equity. The purpose of this automatic adjustment was to avoid the future cost and inconvenience of numerous hearings to determine this issue.

NEB Decision RH-2-94,[4] issued in March 1995, fixed the Canadian Mainline's return on equity for the 1995 test year at 12.25 percent. In order to arrive at this number, the NEB used a deemed capital structure for the Canadian Mainline of 70 percent debt and 30 percent equity. The division between debt and equity is necessary in order to determine the utility's cost of capital, which is the aggregate return on investment that investors require in order to maintain their capital in the utility.

The return is realized in two ways: interest on debt, and dividends and capital appreciation on equity. The calculation of return on debt is generally straightforward, consisting of the weighted average interest rate for the test year on a utility's outstanding long-term debt. Conversely, the rate of return on equity is the subject of considerable dispute. The utility will generally seek a higher apportionment to the equity component, based on its perception of the business risk that it faces.

The NEB, in calculating the return required by equity investors, used its "Equity Risk Premium Method," which requires the NEB to estimate a risk free rate of return based on government bond rates, and adding a premium to account for the perceived risks associated with an investment in a "benchmark" pipeline.[5]

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1 (2004), 319 N.R. 171, 2004 FCA 149.

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

3 NEB, *In the Matter of TransCanada PipeLines Limited, Application Requesting a Review and Variance*, Reasons for Decision RH-R-1-2002 (February 2003).

4 NEB, *In the Matter of TransCanada PipeLines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd., Trans Quebec & Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd. and Trans-Northern Pipeline Inc., Submissions in Respect of Cost of Capital*, Reasons for Decision RH-2-94 (March 1995).

5 *Ibid.* at 2.1, 2.4.

In 2001, TCPL applied pursuant to s. 21(1) of the *NEB Act* for a review of Decision RH-2-94, and to set a fair rate of return for TCPL for the years 2001 and 2002. TCPL asked the NEB to substitute its "Equity Risk Premium" methodology for the "After Tax Weighted Average Cost Of Capital" (ATWC) formula. TCPL asked that the required return on equity for the Canadian Mainline be 12.5 percent for 2001 and 2002, and that the deemed equity component of the capital structure be increased to 40 percent.

As a consequence of TCPL's review request, the NEB conducted hearings between February and April 2002. The NEB then issued Decision RH-4-2001 in which TCPL's ATWC proposal was rejected. The NEB concluded that the rate of return on equity for Canadian Mainline should continue to be based on the adjustment formula contained in Decision RH-2-94. However, the NEB did increase the equity component of the Canadian Mainline's capital structure from 30 to 33 percent.

On 16 September 2002, TCPL applied for a review and variance (pursuant to s. 21(1) of the *NEB Act*) of Decision RH-4-2001.

By virtue of Decision RH-R-1-2002, the NEB declined to vary Decision RH-4-2001.

Generally, when a court of supervisory jurisdiction is reviewing the decision of an administrative body, there will be a significant discussion with respect to the standard of review. However, in this decision, the Court dealt with this issue in a somewhat abbreviated manner. The Court's discussion of this issue is contained in the following passage:

> In view of my conclusion that the appeal should be dismissed, it is not necessary to conduct an extensive standard of review analysis. Even on the most intrusive standard of review (correctness), it has not been demonstrated that the Board erred in law.[6]

The Court also commented on the fact that TCPL had chosen to appeal the Review Decision (RH-R-1-2002), rather than the decision subject to the review request (RH-4-2001). The Court appears to imply that as a consequence of this procedure, it might not be obligated to consider the actual decision, but that it would do so nevertheless.

One of the complaints made by TCPL was that in Decision RH-4-2001 the NEB considered, in assessing the Canadian Mainline's rate of return on equity, the impact on TCPL's customers. TCPL indicated that the consideration of customer issues was appropriate if it were restricted to the costs of the Canadian Mainline in general; however, it objected to those concerns having an impact on the required rate of return on equity. The Court agreed with TCPL's proposition, but stated that the NEB's decision did not improperly consider this issue. The Court made this point as follows:

> While the Board observed that the increase would not be an undue burden on shippers, there is no suggestion that the increase in the equity component of the Mainline's deemed capital structure was in any way suppressed by considerations of its impact on customers or consumers. Nor, as I have said, is there any indication that the Board determined a rate of return on equity for the Mainline and then adjusted it

6 *Supra* note 1 at para. 26.

> downward based on the impact it would have on tolls. In the absence of some indication in the Board's Reasons, there is no basis for such an assumption.[7]

TCPL also argued that the NEB was unfairly biased in favour of the adjustment mechanism contained in RH-2-94. TCPL stated that the NEB had placed an inordinately high onus on it to demonstrate that this adjustment formula should be revised.

The Court rejected TCPL's arguments in this regard. It indicated that when the NEB set out an indefinite process for rate adjustments and an interested party wished to change that process, it had the onus of demonstrating that its proposal was preferable. The Court concluded that the imposition of this onus did not constitute a fettering of discretion, impartiality, or bias, and TCPL's application was dismissed.

B. ALBERTA COURT OF APPEAL

1. *SOLEX GAS PROCESSING CORP. V. ALBERTA (ENERGY AND UTILITIES BOARD)*[8]

In Decision 2004-006[9] the Alberta Energy and Utilities Board (AEUB) dealt with what has been termed as a "sidestreaming" application by Solex Gas Processing Corp. (Solex). Solex sought approval to have their share of the gas flowing through the Nova Gas Transmission Line (NGTL) System diverted to the Harmattan Plant where it would be re-processed and a certain quantity of natural gas liquids (NGL) would be removed. The re-processed gas would then be returned to the NGTL System to be transported to the Cochrane Straddle Plant for further NGL extraction prior to being delivered to market. The Solex application contemplated that the Cochrane Straddle Plant would still receive a sufficient quantity of NGL to ensure its economic viability as is mandated by s. 35 of the *Oil and Gas Conservation Act*.[10]

The AEUB declined Solex's application in Decision 2004-006.

Solex sought leave to appeal Decision 2004-006 pursuant to ss. 26(1) and (2) of the *Alberta Energy and Utilities Board Act*,[11] and ss. 41(1) and (2) of the *Energy Resources Conservation Act*.[12] The grounds of appeal advanced by Solex were as follows:

(a) the AEUB exceeded its jurisdiction under the *OGCA* by seeking to protect the Cochrane Straddle Plant and straddle plants in general from side-streaming;

(b) the AEUB erred in law in concluding that the Solex application should be denied because there was no compelling public interest reason for approving it;

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7 *Ibid.* at para. 42.

8 (2004), 361 A.R. 232, 2004 ABCA 388.

9 AEUB, *Solex Gas Processing Corp.: Application to Amend a Gas Processing Scheme and for a Natural Gas Pipeline*, Decision 2004-006 (27 January 2004).

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

11 R.S.A. 2000, c. A-17 [*EUBA*].

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

(c) the AEUB erred in law in failing to take into account the provision of the *OGCA*, which provides that the purpose of the *OGCA* is to afford each owner the opportunity of obtaining its share of production;

(d) the AEUB erred in law in basing its decision on the potential impact of the sidestreaming on NGL markets and on the desirability of discouraging the proliferation of sidestreaming projects; and

(e) the AEUB contravened s. 7 of the *Administrative Procedures Act*,[13] in failing to make and state findings of fact supporting its decision.[14]

Applications for leave to appeal a Board Decision are heard by a single judge of the Court of Appeal. The Solex leave application was heard in chambers by O'Leary J.A. on 23 June 2004, and the Reasons for Decision were filed on 3 December 2004.

Justice O'Leary first discussed the applicable standard of review. In concluding that the standard was reasonableness, O'Leary J.A. stated as follows:

> However, where the alleged error of law is in respect of a matter within the Board's delegated jurisdiction and involves application of the Board's acknowledged experience and expertise, including decisions requiring the interpretation and application by the Board of the statutes and regulations consigned to its administration, the more deferential standard of reasonableness will be applied.[15]

The concept of the public interest was prevalent throughout the reasons of O'Leary J.A. He concluded the AEUB was entitled to balance the interests of Solex against the impacts of sidestreaming on the straddle plant system. Justice O'Leary reiterated the provisions of s. 4(c) of the *OGCA*, which state that the purpose of this legislation is to "provide for the economic, orderly and efficient development in the public interest of the oil and gas resources of Alberta."[16] He further concluded that a finding by the AEUB that the application was contrary to the public interest was one that was within the Board's jurisdiction.

Justice O'Leary found that the AEUB's jurisdiction to consider the public interest was not limited to the strict application of s. 35 of the *OGCA*. According to O'Leary J.A., the consideration of the public interest goes beyond simply determining whether the sidestreaming application does not encroach upon the minimum volume of NGL to which a straddle plant is entitled. In considering the public interest, the Board was entitled to consider government policy respecting NGL extraction and straddle plants.

Lastly, O'Leary J.A. agreed with Solex that natural gas producers are entitled to extract NGL from the natural gas they own and produce; however, this right is subject to the overall public interest.

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13 R.S.A. 2000, c. A-3.
14 *Supra* note 8 at para. 23, paraphrased.
15 *Ibid.* at para. 26.
16 *Supra* note 10.

Justice O'Leary, in dismissing the leave application, concluded that the test for leave had not been met.

2. *DENE THA' FIRST NATION V. ALBERTA (ENERGY AND UTILITIES BOARD)*[17]

This was an appeal by the Dene Tha' First Nation (DTFN) with respect to certain well licences issued by the Board to Penn West Petroleum Ltd. (Penn West). A single judge of the Court of Appeal granted leave to the DTFN on 11 December 2003, indicating that the questions on appeal were as follows:

> 1. Did the Board err in law or jurisdiction in determining that in order to have standing to advance constitutional and treaty-based arguments, the applicant must establish it has "a legally recognized interest, with respect to the land that may be directly and adversely affected" by the Penn-West Explorations Ltd. applications, and by concluding that the applicant "failed to establish [it] would be potentially negatively or adversely affected."
>
> 2. If the answer to question 1 is yes, what is the correct test for determining such standing.
>
> 3. If the answer to question 1 is yes and standing should have been granted, through what process should the Board have addressed the applicant's arguments.[18]

Penn West had advised the DTFN in 2002 that it proposed to drill a number of wells and put in access roads on certain Crown lands. These lands were not within the reserve of the DTFN, but were alleged by the DTFN to be within their "traditional lands." There were a number of meetings and discussions between Penn West and the DTFN, and Penn West provided a helicopter site tour of the proposed project to certain members of the DTFN.

As part of the consultation process, Penn West attempted to obtain information from the DTFN trappers who were potentially affected. However, the DTFN objected to direct communications between Penn West and the trappers, insisting that communication go through a central consultation office. It was in late November 2002 that Penn West advised the DTFN of the precise legal descriptions of the proposed development.

In late December 2002, the AEUB issued licences for some of the wells' roads. Immediately thereafter, the DTFN filed material with the AEUB seeking to intervene and object to the applications. There was an exchange of correspondence between all parties, following which the Board issued a letter, dated 16 January 2003, stating that the DTFN had not met the test for intervention set out in s. 26(2) of the *ERCA*.[19] In essence, the AEUB concluded that the DTFN was not "directly and adversely affect[ed]," as is stated in this section, by the development.

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17 (2005), 363 A.R. 234, 2005 ABCA 68, leave to appeal to S.C.C. refused, [2005] S.C.C.A. No. 176 (QL).

18 *Dene Tha' First Nation v. Alberta (Energy and Utilities Board)*, [2003] A.J. No. 1582 (QL), 2003 ABCA 372 at para. 6.

19 *Supra* note 12.

The DTFN then applied for a reconsideration of the Board's decision. Both the DTFN and Penn West submitted information to the AEUB setting out their respective positions. On 15 April 2003, the AEUB again concluded that the DTFN did not meet the test of adverse impact and the DTFN was not given intervener status.

The Court discussed the proper application of s. 26(2) of the *ERCA*, which reads as follows:

> 26(2) Notwithstanding subsection (1), if it appears to the Board that its decision on an application may directly and adversely affect the rights of a person, the Board shall give the person
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> (a) notice of the application,
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> (b) a reasonable opportunity of learning the facts bearing on the application and presented to the Board by the applicant and other parties to the application,
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> (c) a reasonable opportunity to furnish evidence relevant to the application or in contradiction or explanation of the facts or allegations in the application,
>
> (d) if the person will not have a fair opportunity to contradict or explain the facts or allegations in the application without cross-examination of the person presenting the application, an opportunity of cross-examination in the presence of the Board or its examiners, and
>
> (e) an adequate opportunity of making representations by way of argument to the Board or its examiners.[20]

The Court concluded that the test has two branches, the first being a legal test, which necessitates an inquiry into whether the claim, right, or interest being asserted is one known to law. The second branch is factual, demanding an inquiry into whether the application before the AEUB may directly and adversely affect such interest.

The Court of Appeal concluded, without much difficulty, that the first test was satisfied. The Court then analyzed the second branch of the test.

The Court asserted that in order for the AEUB to have made a factual finding in favour of the DTFN, it required specific evidence and information as to possible adverse effects. The AEUB was not compelled to find that standing existed as a consequence of a mere assertion of an Aboriginal or treaty right. The Court stated that the information that would speak to this issue was readily available to the DTFN, such as where its members hunt and trap. However, no such specific information was provided to the Board in this case.

In the result, the Court of Appeal held that the AEUB had correctly applied the factual test set out in s. 26(2) of the *ERCA*. The Court further pointed out that it had no jurisdiction to hear an appeal on the Board's determination with respect to the factual component of the test.

The Court then went on to make some comments with respect to consultation, as that formed a considerable part of the argument before it. Likely as a consequence of the decision in *Haida Nation v. British Columbia (Minister of Forests)*,[21] all parties to the appeal conceded that neither Penn West nor the AEUB had a duty in law to consult with the DTFN.

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20 *Ibid.*

21 [2004] 3 S.C.R. 511, 2004 SCC 73.

The Court did suggest, however, that the consultation engaged in by Penn West prior to filing its applications was adequate, or at least not demonstrably inadequate.

C. ALBERTA COURT OF QUEEN'S BENCH

1. *PROVIDENT ENERGY LTD. V. ALBERTA (SURFACE RIGHTS BOARD)*[22]

Provident Energy Ltd. (Provident) brought a judicial review application with respect to Surface Rights Board Decision No. 2003/0143.[23]

This case was the result of a situation that is unfortunately fairly common in Alberta. In 1984, an operator drilled a dry hole and abandoned the well, but failed to obtain a reclamation certificate. The surface interest was subsequently transferred a number of times and at some point, the owner became aware of the prior existence of the well and the fact that no reclamation certificate had been obtained. Pursuant to s. 144 of the *Environmental Protection and Enhancement Act*,[24] a reclamation certificate must be acquired before a surface lease can be surrendered or terminated.

In Decision 2003/0143, the Surface Rights Board referenced the decision of Sirrs J. in *Devon Canada Corporation v. Alberta (Surface Rights Board)*,[25] where it was held that the mere finding that the surface lease is still in effect does not automatically entitle the surface owner to payment for the arrears of rentals. The Surface Rights Board stated as follows:

> The Board having found that the Lease is in effect and that Provident Energy Ltd. is obligated to pay rent to the O'Hares does not automatically entitled the O'Hares to payment for the amount claimed. Justice Sirrs in Devon Canada Corporation and the Surface Rights Board, stated that the Board has discretion in this regard. He held that the Board may deny payment if the owner's claim is unjustified, absurd or provides an unjust enrichment.[26]

The Surface Rights Board went on to find that due to the compaction on the site, the surface owner suffered a loss of use in the form of decreased yields, and Provident was ordered to compensate him on this basis.

Justice Erb dismissed Provident's judicial review application. She concluded that the standard of review to be applied to the decision of the Surface Rights Board was "patent unreasonableness."[27] Applied against such a standard, Erb J. found that Decision 2003/0143 did not warrant interference by the Court.

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22 [2004] A.J. No. 1286 (QL), 2004 ABQB 650.

23 Alberta, Surface Rights Board, *Decision In the Matter of certain lands subject to a surface lease (L.S. 12 wellsite lease) in the North West Quarter of Section 28, Township 50, Range 3, West of the 4th Meridian, in the Province of Alberta*, Decision No. 2003/0143 (6 November 2003).

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

25 (2003), 337 A.R. 135, 2003 ABQB 7 [*Devon*].

26 *Supra* note 23 at 3.

27 *Supra* note 22 at para. 30.

She made the further finding that the *Limitations Act*[28] did not apply, as the Surface Rights Board is a statutory body and thus not subject to its provisions.

This decision represents the application of the principle set out in *Devon*. Prior to *Devon*, it was generally understood that once a surface owner demonstrated that no reclamation certificate was obtained, arrears of rent must be paid. As a result of this decision, the Surface Rights Board is mandated to go beyond simply determining that rental payments ceased in the absence of a reclamation certificate ascertaining non-payment. It must conduct a further inquiry to determine whether there is a factual basis for compensating a landowner.

III. REGULATORY DECISIONS

A. NATIONAL ENERGY BOARD

1. WESTCOAST ENERGY INC. TOLL SETTLEMENT, 2004 AND 2005[29]

Westcoast Energy Inc. (Westcoast) owned and operated a natural gas pipeline system, providing mainline transmission service in Zones 3 and 4. Westcoast and other relevant parties who represented Westcoast's shippers, gas producers, and end-use markets entered into a settlement agreement (the Settlement) regarding the appropriate methodology for fixing tolls in Zones 3 and 4.

In order for the Settlement to be valid, the NEB was required to approve it in its entirety. Pursuant to this, the NEB issued Order TG-3-2004 (the Order), which addressed the tolls charged by Westcoast for mainline transmission services for the 12-month period commencing 1 January 2004.

The objectives of the Settlement were to:

(a) enhance the British Columbia natural gas base;
(b) provide Westcoast's shippers with certainty and stability with respect to tolls;
(c) offer excellent pipeline service at the lowest cost possible without compromising efficiency, reliability, flexibility, utilzation, safety, or the environment;
(d) ensure that Westcoast remained financially viable; and
(e) reduce resources used.

Pertinent terms of the Settlement included the following:

(a) Westcoast's revenue requirements;
(b) the establishment of an appropriate rate base;
(c) the maintenance of deferral accounts;
(d) the establishment of tolls in Zones 3 and 4;
(e) the parameters for discretionary revenue sharing; and

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28 R.S.A. 2000, c. L-12.
29 RH-1-2004 (August 2004).

(f) a measurement improvement program to enhance measurement and reporting practices and requirements.

On 12 August 2004, the NEB issued Order TG-3-2004, finding that the Settlement was just and reasonable.

B. ALBERTA ENERGY AND UTILITIES BOARD

1. DECISION 2004-034: ANADARKO CANADA CORPORATION[30]

a. Background

Anadarko Canada Corporation (Anadarko) applied to establish separate holdings for gas production. The application was made pursuant to s. 79(4) of the *OGCA*[31] and s. 5.190 of the *Oil and Gas Conservation Regulations*.[32] The application was in respect of the Westerose South Glauconitic A Pool, a non-associated gas pool underlying more than 200 sections in portions of Townships 43 to 46, Ranges 1 to 4, W5M. This pool had been producing since 1977. The application was concerned with three wells, of which Anadarko had an interest in two. Cansearch Resources Ltd. (Cansearch) had an interest in the third adjoining well. The Board treated the application as one that would result in reduced gas well spacing and, therefore, considered it within the framework of s. 4.040(3) of the *OGCR*. This section provides that reduced spacing will not be permitted unless the following factors are present:

(a) improved recovery;
(b) the need for additional wells to drain the pool at a reasonable rate;
(c) the existence of reduced spacing within the pool; and
(d) the desirability of increased gas.

In addition to these factors, the AEUB also considered whether reduced gas well spacing would result in inequities between Anadarko and Cansearch.

Cansearch filed an Intervention seeking to have the AEUB decline the applications, submitting that the evidence put forward by Anadarko did not demonstrate that the incremental recovery of gas through the infill wells would be significant. Cansearch further submitted that the reduced spacing requested by Anadarko would result in inequitable drainage and decreased production from its well.

Cansearch took issue with Anadarko's technical evidence and raised a philosophical objection to the applications. Cansearch submitted to the AEUB that it was a private, family-operated company whose business strategy was directed towards exploration, as opposed to increased production through infill wells. Cansearch acknowledged that reduced well spacing had been previously approved for the application area; however, it indicated that

30 *Applications for Special Gas Well Spacing* (4 May 2004).
31 *Supra* note 10.
32 Alta. Reg. 151/1971 [*OGCR*].

these applications did not affect Cansearch's position, and each application should be considered on its own merit.

Cansearch further submitted evidence to show that the pool was being drained at a fairly even rate under the subject lands. This view was based on pressure data; however, the pressure data was not put before the Board at the hearing.

The AEUB considered the evidence and approved the application. The Board was satisfied that there was a significant degree of heterogeneity in the pool and that there was not good communication between Anadarko's wells and Cansearch's well.

Interestingly, the AEUB did not consider it important to measure with any degree of accuracy the incremental gas that would be recovered under Anadarko's reduced spacing scheme, although the Board did indicate that such recovery would be "modest."[33]

The AEUB appeared influenced by the fact that both Anadarko and Cansearch concurred in the view that the remaining life of all three wells was between 40 and 60 years, which the Board viewed as extraordinarily long. Note was also taken of Cansearch's position that the drilling of additional wells would shorten the three wells' life by approximately ten years, still leaving a considerable period of time over which gas would be recovered. The AEUB also acknowledged Cansearch's business philosophy, but indicated that it should not override the benefits that would result from accelerating production. Lastly, the Board indicated that where a single pool is being competitively produced, the unique business strategy employed by Cansearch may not be viable.

2. DECISION 2004-056: BUMPER DEVELOPMENT CORPORATION LTD.[34]

Bumper Development Corporation (Bumper) applied pursuant to s. 2.020 of the *OGCR*[35] for approval to drill a well and construct an access road. The application was filed on a routine basis, and the AEUB issued Well Licence 0287658 on 28 May 2003.

In early June 2003, Bumper completed the construction of the well site and access road. H.G. Norman and Sons (Norman) filed a request pursuant to s. 40 of the *ERCA*[36] requesting that the Board review the licence. Norman owned land adjacent to the access road and was concerned that the location of the access road would impact the drainage of its land.

The owner of the land upon which the well and access road were located did not object to the project.

Norman argued that it had not been consulted by Bumper in advance of the application being filed. It noted that the October 2003 edition of the AEUB's *Guide 56*[37] required such notification. In response, Bumper argued that it had complied with the October 2000 edition

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33 *Supra* note 30.
34 *Review of Well Licence No. 0287658, Davey Field* (13 July 2004).
35 *Supra* note 32.
36 *Supra* note 12.
37 AEUB, *Guide 56: Energy Development Applications and Schedules* (October 2003).

of *Guide 56*,[38] which did not require Norman to be notified. However, Bumper indicated that it did try to address Norman's concerns once it was made aware of them.

The AEUB indicated that while Bumper did meet the strict technical requirements of the then-current *Guide 56*, the spirit and intent of this document did require that Bumper notify Norman prior to filing the application.

A further ground of objection was that the material used to construct the road was causing metal contaminants to be washed onto Norman's lands. Bumper concurred that elevated levels of certain heavy metals had migrated onto Norman's lands, and Bumper committed to conduct further vegetation, water, and soil monitoring.

The AEUB further discussed the flooding and drainage issue raised by Norman. Norman stated that the location of the access road would result in an additional volume of water on its land. This excess water would require additional time for the land to dry and result in a loss of farming time. Bumper had been dealing with Alberta Environment with respect to the drainage issue and had in fact installed three culverts under the access road, which it indicated had resolved the drainage concern.

The AEUB also considered the views of the owner of the land upon which the project was located who did not concur with the view expressed by Norman, and indicated that his position was that the location of the access road would not adversely affect the drainage.

In the result, the AEUB allowed Bumper's licence to continue.

3. DECISION 2004-089: BLACKROCK VENTURES INC.[39]

BlackRock Ventures Inc. (BlackRock) filed an application with the AEUB pursuant to s. 10 of the *Oil Sands Conservation Act*,[40] for approval to construct and operate a thermal bitumen recovery project using steam-assisted gravity drainage (SAGD). As described by the AEUB, SAGD is the process whereby

> the oil sands zone is accessed by drilling horizontal well pairs from the surface....
>
> Upon commencement of the SAGD process, steam is injected into both the upper and lower wells. Once pressure communication has been established between the two wells, steam is injected into the upper well only and the lower well becomes the producer.
>
> During the SAGD production, steam injected into the upper well flows through the bitumen-depleted zone to the cold interface, where it condenses, heating the bitumen. Mobilized bitumen then drains by gravity to

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[38] AEUB, *Guide 56: Energy Development Application Guide* (October 2000), updated as Directive 056 (September 2005).

[39] *Application for a Steam-Assisted Gravity Drainage Project for the Recovery of Bitumen* (19 October 2004).

[40] R.S.A. 2000, c. O-7 [*OSCA*].

the lower well and is produced. As the pay zone is exploited, the steam chamber continues to rise and spread, eventually reaching the top of the bitumen-bearing zone.[41]

BlackRock's project contemplated two phases, the first consisting of approximately 56 SAGD well pairs and associated steam generation infrastructure. The second phase contemplated an additional 60 well pairs and associated infrastructure and steam generation.

Interventions were filed by area residents (the interveners) who argued that the project would negatively impact their quality of life and the value of their land.

During the hearing, the AEUB panel and staff conducted a site visit to the property of the interveners and the existing BlackRock operations. Neither BlackRock nor the interveners participated in this visit.

One of the issues that arose during the hearing was the relationship between lease boundary setbacks and maximum resource recovery. BlackRock's initial application contemplated a 50-m setback from the lease boundary edges, which was a reduction from the 100-m setback implemented in BlackRock's earlier pilot project.

In order to accommodate the concerns of Imperial Oil (who had filed an objection respecting lease boundary setback distances that was withdrawn prior to the hearing), BlackRock temporarily increased the lease boundary setback to 150 m. BlackRock indicated that in the future, when further technical information became available, it would seek to drill additional infill well pairs at a setback distance of 50 m.

The AEUB was concerned that the increase in lease boundary setback, which was an accommodation to Imperial Oil, not compromise the maximum recovery of resources. The Board requested that BlackRock and Imperial Oil continue to work together to ensure maximum resource recovery.

One of the issues dealt with by the AEUB was the interveners' concern that the project would result in increased arsenic levels in area groundwater. Apparently, data gathered by Imperial Oil at its Cold Lake Cyclic Steam Stimulation Project had indicated that heated wellbores in shallow formations might increase the solubility of the arsenic near the wellbore. The data indicated that the arsenic levels decreased at a distance of 300 to 400 m from the wellbore. This was a concern because a number of the area residents' water supply wells were located within 400 m of the BlackRock operations.

BlackRock stated that its risk assessment demonstrated that the safety of area drinking water would not be compromised and that its groundwater monitoring program would detect any increases in arsenic. BlackRock's conclusion that human health would not be affected as a result of the project was supported by Alberta Health & Wellness.

However, the interveners were of the view that BlackRock did not provide a complete assessment of the risk of arsenic exposure, particularly to children. There was also a concern

[41] AEUB, *EUB Inquiry: Gas/Bitumen Production in Oil Sands Areas* (March 1998) at 2.

that local doctors and nurses were not adequately trained to identify health problems related to exposure to arsenic through drinking water. As a result, a request was made that BlackRock and other area operators contribute to a regional health centre.

The AEUB took note of the fact that the Imperial Oil data regarding thermal arsenic increases may not be applicable to the BlackRock project due to lower operating temperature and lower wellbore density. The Board further noted that BlackRock's groundwater monitoring program was designed to detect increased arsenic levels. The AEUB found that BlackRock's human health risk assessment was acceptable, but did mandate that BlackRock supply the Board with a copy of its groundwater monitoring program after it had been approved by Alberta Environment. The Board also requested that BlackRock provide an annual groundwater monitoring report.

The interveners also had concerns with respect to the project's effect on surface water. This concern arose from the fact that the project contemplated the use of produced water for steam injection. The interveners were concerned that produced water could migrate to local lakes and other freshwater bodies. There was also a concern that surface spills could travel to lakes using shallow ground water as a conduit. The interveners requested that the AEUB acquire the implementation of measures such as seismic monitoring or thermal scanning by remote satellites.

The AEUB stated that the greatest risk to surface water was from surface spills and was satisfied with the mitigation measures proposed by BlackRock. In response to the concern regarding spills, the Board noted that BlackRock was required to comply with AEUB regulations concerning spill management and emergency response planning. Alberta Environment advised that it intended to require surface water monitoring for the protection of local lakes.

Notwithstanding BlackRock's intention to use produced water, it did indicate that the use of fresh water would be required should there be short periods of upset conditions in the produced water treatment facilities. As a consequence, BlackRock was applying to Alberta Environment to continue its existing licence allowing for the withdrawal of $600m^3$/day from the Quaternary formation.

The interveners were concerned that there was no method for monitoring the use of produced water in relation to fresh water. The AEUB noted that notwithstanding BlackRock's request for an extension of its fresh water withdrawal permit, it required BlackRock to ensure that 90 percent of the fresh water used was recycled, and within one year following the start of commercial operations, to provide an update as to the ratio of produced water use versus fresh water use.

BlackRock was required to deal with intervener concerns with respect to project emissions. These concerns related to acid deposition and ground level ozone. The interveners expressed a further concern regarding hydrogen sulfide and arsenic emissions from the flare, steam generators, or well pads. However, the interveners provided no scientific or empirical evidence to support these concerns.

As a consequence of the absence of evidence to the contrary, the AEUB accepted BlackRock's evidence that it would not exceed the Alberta Ambient Air Quality Guidelines. The Board was satisfied with BlackRock's commitment to an on-lease air-monitoring program, providing for six months of continuous monitoring. BlackRock's commitment to respond to air quality and odour concerns was noted by the Board, and it indicated that if a resident had a concern regarding odours, a complaint could be made to the Board's Bonnyville field centre.

The noise generated by the project was also expressed as a concern by the interveners. On the basis of the noise impact assessment conducted by BlackRock, the AEUB was satisfied that the project would be within the parameters of the Board's Noise Control Directive, Interim Directive ID 99-08.[42]

The interveners made submissions with respect to the effect of BlackRock's project on land values. The AEUB indicated that although it lacked the jurisdiction to award compensation for land devaluation, impacts on land values were one factor that it would consider during the approval process.

The interveners complained that they did not receive notice of the project until 21 January 2004, as they had moved onto their properties between 2002 and 2003, despite the fact that BlackRock had initiated public consultation in 2000. They further indicated that they received no application information until 20 February 2004, five months before the hearing. They then engaged in consultation with BlackRock, but were unable to have their concerns resolved.

The AEUB stated that BlackRock had satisfied the consultation requirements with local area stakeholders. However, it was noted that all involved parties could have been more attentive to the issue of new residents moving into the area.

4. DECISION 2004-090: EOG RESOURCES CANADA INC.[43]

EOG Resources Canada Inc. (EOG) applied for approval to drill a proximity critical level 2 sour gas well in the Bragg Creek area. The Emergency Planning Zone (EPZ) for this well would include all of a residential subdivision known as the Wintergreen Woods, consisting of 77 residences.

A number of area residents filed interventions opposing EOG's application. These objections were based on concerns regarding consultation, EOG's Emergency Response Plan (ERP), air quality, and property devaluation.

EOG's consultation process began in February of 2003. There were meetings with both landowners adjacent to the proposed well and discussions with some residents in the Wintergreen Woods subdivision. As a consequence of these discussions, EOG determined to include all of the Wintergreen Woods residents in future consultation or emergency

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42 AEUB, *Noise Control Directive*, Interim Directive ID 99-08 (1 November 1999).

43 *Application for a Licence for a Natural Gas Well, Jumping Pound West* (19 October 2004).

planning response. EOG identified four possible surface locations for the well and in September of 2003 conducted a meeting with landowners in the immediate vicinity of the proposed location. However, this meeting did not include residents of Wintergreen Woods.

The AEUB noted that the selected well location was not the ideal location for EOG, but it was the preferred location for the most directly affected landowners. EOG acknowledged at the hearing that it did not include the Wintergreen Woods residents in the decision to change the original location of the well; however, it indicated that it had informed these individuals shortly after the location was chosen and no concerns were raised at that time.

Not surprisingly, many Wintergreen Woods residents had a different view of EOG's consultation efforts and submitted to the Board that EOG had not conducted its negotiations in good faith. Specifically, residents felt that they should have been included in the decision to change the well site and that a surface location resulting in the residents being outside the EPZ should have been chosen.

The AEUB was generally satisfied with the consultation carried out by the EOG. However, it did comment on the fact that Wintergreen Woods residents were included in the initial consultation, but were largely excluded from the decision to change the well location. The AEUB felt that when a party is involved in the initial consultation with respect to a project, that consultation should continue uninterrupted and the residents should have been involved in the decision to change the surface location.

The AEUB further addressed issues related to public safety and air quality emissions. The Board noted that the ERP filed by EOG met or exceeded the Board's *Guide 71*[44] requirements. Specifically, the requirement that where an EPZ covers only part of a rural subdivision the entire subdivision must be included in the EPZ was acknowledged.

Some of the safety and evacuation concerns identified by the Wintergreen Woods residents were as follows:

(a) a single access route across an unmanned bridge;
(b) the high number of recreational users in the area; and
(c) the need for a "dry run" evacuation exercise.

The AEUB acknowledged these concerns, but was of the view that EOG's measures in this regard were adequate, noting that the ERP contained additional safety measures, such as the use of a "rover" stationed at the bridge, stationary monitors located throughout the planning zone, and early notification and evacuation prior to any release. The Board's view was that a "dry run" evacuation was not required, but did note that EOG had made a commitment to conduct a communication exercise designed to test its response protocols.

Concerns were raised by some residents that the project would have an adverse effect on air quality and emissions. EOG provided the AEUB with scientific evidence in the form of

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[44] AEUB, *Guide 71: Emergency Preparedness and Response Requirements for the Upstream Petroleum Industry* (June 2003), re-issued as Directive 071 (20 July 2005).

plume dispersion modelling, which indicated that in a worst-case scenario[45] the concentrations of hydrogen sulfide would result in no more than temporary discomfort to the residents. EOG also indicated that should the well prove to be productive, a permanent flare stack would be placed at the well site, but that it would not be used for continuous flaring, but rather only in response to an upset condition.

The AEUB was satisfied with EOG's proposed measures. The Board noted that EOG had agreed to monitor the air quality to ensure that guidelines were being met. Furthermore, in the event that EOG determined that flaring was required, they would need to submit an application and put forward modelling to show that emissions were within air quality guidelines.

The Wintergreen Woods residents further argued that EOG's well would negatively impact their property values. They submitted a report entitled "Impact of Oil and Gas Activity on Rural Residential Property Values." It was argued that the public perception associated with having a sour gas well in the vicinity of the residents would be detrimental to property values. Accordingly, the Board was asked to add as a condition to any approval a requirement that EOG provide compensation for any property devaluation.

The AEUB declined this request, stating that it did not have the statutory jurisdiction to order compensation to residents, even if there was compelling evidence that EOG's well would result in property devaluation. The property valuation issue was stated to be only one of a number of "impacts"[46] that the AEUB was mandated to consider in the course of considering the application.

The AEUB determined that the application should be approved, subject to conditions and commitments with respect to air quality and safety. The Board noted that breach of the conditions it imposed could result in suspension of the approval and shut-down of the facility.

5. DECISION 2005-009: PROVIDENT ENERGY LTD.[47]

Provident submitted an application to the AEUB for a change in pool designation from Gilby Basal Mannville A3A to Jurassic pursuant to s. 33 of the *OGCA*.[48] Progress Energy Ltd. (Progress) and ARR Resources Ltd. (ARR) subsequently filed Interventions. Progress asserted that the evidence in support of a pool re-designation was conflicting and inconclusive. ARR objected due to concerns that the pool re-designation would affect its gross overriding royalty interest.

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45 "Worst-case scenario" is defined as "a well blowout at the theoretical maximum rate under the worst-case weather conditions" (*supra* note 43 at 8).

46 *Ibid.* at 11.

47 *Application for a Change in Pool Designation* (15 February 2005).

48 *Supra* note 10.

This application was similar to the one resulting in Decision D 95-10,[49] known as the Hillcrest/Truax Decision. In D 95-10, the AEUB undertook a similar analysis with respect to the boundary between the Mannville and Jurassic strata and outlined certain criteria to be used in making the distinction between the two strata. These criteria included: mineralogy, the presence of coal, sulphide mineralization, palaeontology, geophysical log signatures, and trace fossils.

The AEUB considered all of the evidence provided and concluded that the pool re-designation sought by Provident was supported by the evidence. The Board placed considerable emphasis on the fact that the core log analysis submitted by Provident showed the presence of *in situ* phosphates, which the Board felt was a significant indicator of the Jurassic, rather than Mannville, strata.

This decision is interesting from the perspective of the AEUB's discussion of the standard of proof required for a pool re-designation. Progress, in its opposition to the application, argued that in the interests of the certainty as to ownership of mineral rights required by the industry, the Board should not allow pool re-designation applications in the absence of "definitive" or "compelling evidence." The AEUB specifically addressed this position a number of times in the decision. The Board rejected Progress' certainty requirement as follows:

> Operators must be aware that the EUB's initial zone determinations and, consequently, the corresponding pool designations are often based on limited available data. Progress commented on the need for regulator fairness, and in that respect the examiners believe the fairest approach is to make a determination based on a balance of the evidence presented to the Board, rather than the need for conclusive evidence before a change would be contemplated.[50]

Although it does not appear in the written decision, Progress directed the Board's attention to Decision 2003-080 (Stylus),[51] another application contemplating pool re-designation. In Stylus, the AEUB declined to make the requested pool re-designation on the basis that the applicant had failed to present "definitive evidence."[52]

It remains to be seen whether this decision will result in a proliferation of pool re-designation applications, particularly in light of the increasing number of deeper, higher risk plays resulting from a maturing basin.

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49 AEUB, *Hillcrest Resources Limited: Application to Determine the Base of Mannville in Township 40, Range 5, West of the 5th Meridian*, Decision D 95-10 (30 August 1995).

50 *Supra* note 47 at 14.

51 AEUB, *Stylus Exploration Inc.: Application for Approval to Produce Gas, Hardy Field*, Decision 2003-080 (4 November 2003).

52 *Ibid.* at 5.

C. JUDICIAL AND REGULATORY DECISIONS IN RELATION TO GAS OVER BITUMEN

Prior to discussing the latest regulatory developments in this ongoing issue, it is useful to briefly review the legal and procedural background. Below is a chronological outline of events respecting the gas over bitumen debate:

- In 1996, the AEUB perceived a concern with respect to potential adverse effects of gas production on bitumen in associated pools.

- In 1997, the AEUB conducted a general inquiry with respect to this issue.

- In March 1998, the AEUB released the results of its inquiry entitled *Gas/Bitumen Production in Oil Sands Areas*,[53] in which the Board accepted the premise that the production of associated gas could have a negative effect on bitumen production.

- In 1999, the AEUB issued Interim Directive 99-1,[54] which set the parameters on applications for gas production in specified areas. Pursuant to ID 99-1, an applicant had to demonstrate that the gas was non-associated or, if associated, why production should be permitted. Wells drilled prior to 1 July 1998 were exempt from ID 99-1.

- The post-ID 99-1 applications to produce gas resulted in extensive hearings. On 30 March 2000, the AEUB issued Decision 2000-22,[55] in which it declined to allow production from 146 wells in the Surmont Area.

- On 18 March 2003, Decision 2003-023[56] was issued by the Board and, as a result, 60 wells in the Chard-Leismer Area were shut in.

- General Bulletin 2003-012[57] was issued in April of 2003. With General Bulletin 2003-012, the AEUB indicated that the decision on exempted wells would be revisited and invited submissions from interested parties.

- On 3 June 2003, the AEUB issued General Bulletin 2003-016,[58] which amended ID 99-1 in that the affected area was reduced; however, all the wells would be shut in.

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53 *Supra* note 41.

54 AEUB, *Gas/Bitumen Production in Oil Sands Areas - Application, Notification, and Drilling Requirements*, Interim Directive 99-1 (3 February 1999) [ID 99-1]. There were four subsequent amendments to ID 99-1.

55 AEUB, *Gulf Canada Resources Limited Request for the Shut-In of Associated Gas, Surmont Area*, Decision 2000-22 (30 March 2000).

56 AEUB, *Chard Area and Leismer Field, Athabasca Oil Sands Area: Applications for the Production and Shut-in of Gas*, Decision 2003-023 (18 March 2003).

57 AEUB, *Gas Production in Oil Sands Areas*, General Bulletin GB 2003-12 (3 April 2003).

58 AEUB, *Proposed Conservation Policy Affecting Gas Production in Athabasca Wabiskaw-McMurray Oil Sands Areas*, General Bulletin GB 2003-16 (3 June 2003).

- The Board indicated that it felt that the protection of the bitumen resource required the shut-in of all Wabiskaw-McMurray gas wells in the area. It invited submissions for this proposal and consultation meetings were held in July of 2003.

- In July 2003, the AEUB issued General Bulletin 2003-028,[59] which set out a staged approach to dealing with the gas/bitumen issues.

  Phase 1: Interim shut in of 938 wells including those exempted under ID 99-1. Exemptions should be granted if non-association was demonstrated.

  Phase 2: Parties could challenge the exemptions granted under Phase 1.

  Phase 3: Upon the completion of the Regional Geological Study (RGS), the AEUB would determine the final status of gas production.

- The shut-in order was challenged by virtue of judicial review in the Alberta Court of Queen's Bench and statutory appeal in the Alberta Court of Appeal. The judicial review application was dismissed by Hillier J. with reasons dated 23 October 2003.[60]

- The RGS was released at the end of December 2003[61] and found 464 gas pools associated with bitumen and 313 gas pools were classified as non-associated.

1. DECISION 2004-045: PHASE 3 PROCEEDINGS UNDER BITUMEN CONSERVATION REQUIREMENTS AND APPLICATIONS FOR APPROVAL TO PRODUCE GAS IN THE ATHABASCA WABISKAW-MCMURRAY AREA[62]

This hearing was conducted in order to consider submissions with respect to the production of gas bearing intervals in the oil sands that were the subject of GB 2003-028.[63] In accordance with GB 2003-028, a Board staff submission group (SSG) submitted recommendations to the AEUB respecting the continuation or variance of a production status of wells contemplated by GB 2003-028. Parties that disputed the findings of the SSG were permitted to make submissions, and the hearing was subsequently conducted.

Although much of the evidence and argument at this hearing centred on technical and geologic issues, the Board did deal with a number of legal issues. By way of example, some parties questioned the authority of the AEUB to conduct the proceeding. In reply, the Board stated that it had the mandate to manage all energy resources and had the exclusive jurisdiction under Alberta's legislative energy regime to address conservation issues. The

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59 AEUB, *Bitumen Conservation Requirements Athabasca Wabiskaw-McMurray*, General Bulletin GB 2003-028 (22 July 2003).

60 *BP Canada Energy Company v. Alberta (Energy and Utilities Board)* (2003), 356 A.R. 363, 2003 ABQB 875.

61 AEUB, *Athabasca Wabiskaw-McMurray Regional Geological Study*, Report 2003-A (31 December 2003).

62 31 May 2004.

63 *Supra* note 59.

AEUB concluded that its jurisdiction stemmed from its general and specific duty with respect to the conservation of crude bitumen.

A number of parties also questioned the Board's perceived need for an expedited hearing process, which, in their view, jeopardized the fairness of the proceeding. The AEUB maintained that the danger to potential bitumen recovery was such that the delay which would necessarily result from a more protracted hearing process was unacceptable.

The participation of SSG in the process gave rise to concerns with respect to the reasonable apprehension of bias. The AEUB perceived these concerns as being based on the view that the proceeding before it was an extension of previous proceedings or Board-sponsored initiatives with respect to the issue of bitumen conservation. The Board stated that this was not the case, and that the present proceeding was independent of both previous AEUB proceedings with respect to bitumen conservation and the GB 2003-028 consultation process.

The AEUB then considered the technical evidence and issued an order with respect to the shutting in of production from certain intervals.

The AEUB noted the suggestion of one party that the Board recommend that the Alberta Government purchase the gas that would have been produced absent the Board's shut-in orders. The Board declined to make a recommendation, but indicated that it would draw this proposal to the attention of the Alberta Government.

The Board also took note of the fact that the Alberta Court of Appeal granted leave for appeal of Decision 2003-023.[64] The Board further noted the "stay" with respect to the EnCana and Canadian Natural Resources Ltd. (CNRL) wells, considered in Decision 2003-023 and in the associated lease decision, stating that the stay applied only to the perforated intervals referenced in Decision 2003-023 and did not extend to distinct intervals within the same wellbores.

2. DECISION 2004-062: REVIEW OF WELLS WITH WABISKAW-MCMURRAY INTERVALS PREVIOUSLY ALLOWED TO PRODUCE GAS BY DECISION 2003-023[65]

This decision resulted from a review of approvals to produce from the intervals identified in Decision 2003-023.[66] In March of 2004, the AEUB considered whether it needed to review approvals for gas for certain wells for the area considered as part of Decision 2003-023. The issue before the Board was whether the subject intervals contained gas associated with bitumen, such that the conservation of bitumen would be negatively affected. An expedited hearing limiting the scope for this hearing was contemplated by the Board.

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64 *BP Canada Energy Co. v. Alberta (Energy and Utilities Board)* (2004), 30 Alta. L.R. (4th) 248, 2004 ABCA 75.

65 *Chard Area and Leismer Field* (27 July 2004).

66 *Supra* note 56.

A concern was expressed with respect to the jurisdiction of the AEUB to review these wells using an expedited hearing process. In response, the Board noted that the gas pools were in an advanced state of depletion such that there was a significant risk to bitumen recovery, rendering a more protracted hearing unacceptable.

Further, the AEUB considered that it had the jurisdiction to review Decision 2003-023 pursuant to the provisions of s. 39 of the *ERCA*,[67] which permits the Board to review one of its own decisions on its own initiative.

The AEUB was also of the view that it could properly take into account the results of the RGS as evidence that was not available to it during the hearings that resulted in Decision 2003-023.

The Board indicated that in light of the urgency of the bitumen conservation issue, it was deviating from its usual practice of preparing a full report. The Board considered the technical evidence and issued an order that 36 wells (in addition to those ordered shut in by Decision 2003-023) be shut in by 1 September 2004.

3. DECISION 2004-88: PHASE 3 FINAL PROCEEDING UNDER BITUMEN CONSERVATION REQUIREMENTS, ATHABASCA WASBISKAW-MCMURRAY[68]

General Bulletin 2003-028[69] (Phase 3) outlined a final hearing to deal with any remaining disputes over allowable gas production. In advance of same, a pre-hearing meeting was held to consider the scope of the Phase 3 proceedings and identify parties that might participate.

There was an issue as to which wells should be considered in the Phase 3 proceedings. Some parties argued that only those wells subject to the Board's interim decisions should be considered, while the Board staff indicated that the scope should not be so restricted.

The AEUB concluded that Phase 3 should be broad enough to include all non-confidential wells and intervals within the RGS; however, the wells shut in by Decision 2000-22[70] would not be considered in the final hearing.

Some parties requested that prior to the final hearing, there be interim hearings which dealt with only conceptual or technical issues. The AEUB considered that such a process would unduly delay the ultimate resolution of the issue and declined this request.

There was also some issue as to whether the Phase 3 hearings should be restricted to a review of Board interim decisions or a hearing *de novo*. The AEUB indicated that while the hearings were more than a review of earlier decisions, it would consider only issues related

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67 *Supra* note 12.
68 Pre-hearing Meeting Decision (14 October 2004).
69 *Supra* note 59.
70 *Supra* note 55.

to the intervals that were the subject of Decision 2004-045, Decision 2004-062, or Interim Shut-In Order 04-002.[71]

The scope of the evidence to be presented at the Phase 3 hearings was also discussed. A number of parties wanted evidence to be restricted to that not previously put before the Board. Not surprisingly, in light of the complexity of the economic and conservation issues, the Board declined to impose any evidential restrictions.

4. *BP CANADA ENERGY COMPANY V. ALBERTA (ENERGY AND UTILITIES BOARD)*[72]

This was an application to the Court of Appeal seeking leave to appeal GB 2003-028[73] and a stay of the resulting shut-in order. The grounds of appeal proposed by the applicants included:

> The Board committed the following breaches of the *Administrative Procedures Act*[74] and the principles of natural justice:
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> (a) failing to provide the opportunity for affected parties to furnish relevant evidence to the Board;
> (b) failing to inform interested parties of facts in the Board's possession adverse to the interests of those interested parties;
> (c) failing to provide any or adequate reasons for its decisions.[75]

The Court dealt with the issue of whether the appeal would unduly hinder the progress of the action. It regarded the "action" as the ongoing process employed by the Board with respect to bitumen conservation.[76]

The Court further questioned whether any remedy on appeal would be of any assistance to the applicants, given that the AEUB intended to commence hearings with respect to this issue in March 2004. The Court noted that any appeal would be unlikely to be heard prior to the commencement of the March 2004 proceedings, with the result that the appeal may be moot.

In the result, the Court concluded that it did not have sufficient evidence to determine the issue of mootness. The Court concluded that the test for leave had been satisfied.

The Court also dealt with the application to seek a stay of the shut-in order resulting from GB 2003-028. In determining this issue, the Court went through the tripartite sequential test

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71 AEUB, *Phase 3 Proceedings Under Bitumen Conservation Requirements and Applications for Approval to Produce Gas in the Athabasca Wabiskaw-McMurray Area*, Decision 2004-045 (31 May 2004); AEUB, *Review of Wells with Wabiskaw-McMurray Intervals Previously Allowed to Produce Gas by Decision 2003-023, Chard Area and Leismer Field*, Decision 2004-062 (27 July 2004); AEUB, Interim Shut-In Order 04-002 (8 June 2004).

72 (2004), 346 A.R. 147, 2004 ABCA 32 [*BP Canada Energy Co.*].

73 *Supra* note 59.

74 *Supra* note 13.

75 *Supra* note 72 at para. 40.

76 *Ibid.* at para. 42.

set out in *RJR-MacDonald Inc. v. Canada (A.G.)*.[77] The Court concluded that while the questions before it were not frivolous, but rather seriously arguable, the balance of convenience favoured the continuation of the shut-in order. In reaching this conclusion, the Court made reference to the Board's assessment that the content of the bitumen reserves exceeded that of the shut-in gas production by 600 percent.

The Court also made reference to the principles of equity. It noted that the applicants offered no explanation for the failure to bring a stay application between the issuance of GB 2003-028 in July of 2003 and the stay application brought on 1 September 2003. The Court further commented that the applicants did not submit an undertaking as to damages in the event that the appeal was unsuccessful.

5. *BP ENERGY COMPANY V. ALBERTA (ENERGY AND UTILITIES BOARD)*[78]

In this decision, the Court of Appeal dealt with two issues:

(a) the refusal by the Board to grant an adjournment of interim proceedings related to bitumen conservation of the interim hearing scheduled for 8 March 2004; and

(b) the decision of the Board to include certain wells in the proceedings constituting Phase 3 of the gas/bitumen process that were excluded from Decision 2003-023 (Chard-Leismer).

With respect to the first issue, the Court of Appeal had little difficulty concluding that the AEUB was entitled to be the master of its own process. The Court of Appeal considered that prior to interfering with the Board's refusal there must be found to have been "egregious" conduct by the AEUB. The Court stated: "There are sound policy reasons for ensuring this Court's function is not to supervise every step of the Board. The legislation clearly intends the Board to determine and govern its own process."[79]

The Court also considered that the adjournment applications were premature. There was an acknowledgement that the refusal to grant an adjournment could be found to be a breach of procedural fairness; however, this issue could not be determined prior to the hearing and decision. The Court concluded that an appeal based on the failure to grant an adjournment could not be properly adjudicated until the final decision of the Board was issued.

The Court concluded that the applicants had met the test for leave with respect to the appeal of the decisions to include wells not subject to the original shut-in order in GB 2003-028[80] and included in Decision 2003-023.[81]

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77 [1994] 1 S.C.R. 311.
78 *Supra* note 64.
79 *Ibid.* at para. 24.
80 *Supra* note 59.
81 *Supra* note 56.

The Court concluded that pursuant to s. 3(5) of the *Oil Sands Conservation Regulation*[82] and s. 39 of the *ERCA*,[83] the Court had the authority to review any decision made by it. However, the Court concluded that the applicants did not receive notice of the Board's decision to review the Decision 2003-023 wells. The Court rejected the respondent's argument that notice to review these wells should have been inferred from GB 2003-028.

The Court granted the applicant's request for a stay of proceedings under GB 2003-028, but only insofar as those were applicable to the applicant's wells that were considered in GB 2003-023.

6. *ENCANA CORP. V. ALBERTA (ENERGY AND UTILITIES BOARD)*[84]

This was a decision of the Alberta Court of Appeal respecting applications for leave to appeal Decision 2004-045,[85] being the Phase 3 proceedings pursuant to GB 2003-028[86] brought by EnCana, Paramount Energy (Paramount), Devon Canada Corporation, and Giant Grosmont Petroleums Ltd. In addition, the applicant sought a stay of the order shutting in certain of their gas wells.

The argument of Paramount was essentially that because the Board had no jurisdiction to compensate Paramount in the event the Board's interim decision to shut in Paramount's wells was reversed, it lacked the authority for the interim order. Paramount relied on the Supreme Court of Canada's decision in *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*,[87] arguing that "a regulatory body has no jurisdiction to grant an interim order unless it also has the power to review and remedy its effect should the interim order be varied or rescinded upon a full and final hearing."[88]

The Court of Appeal rejected Paramount's arguments. It stated that the *Bell Canada* decision was concerned with an exercise of intrinsically financial matters, which differed from the resource conservation issues before the AEUB. It pointed out that the Board's primary objectives are the conservation of energy resources and the protection of the public interest, and that its enabling legislation did not permit the interpretation sought by Paramount. The Court described the AEUB's mandate as follows:

> Its overriding mandate to conserve energy resources in the public interest alone supports the view that it was intended to have that [interim shut-in] power. If it lacked interim shut-in authority, how could it ever fulfill its mandate in emergent situations? To put the matter another way, given the nature of the resources it is required to protect for the public, its ability to conserve resources could be seriously thwarted if it could only take preventative action after a full and final hearing.[89]

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82 Alta. Reg. 76/1988.
83 *Supra* note 12.
84 (2004), 354 A.R. 380, 2004 ABCA 259 [*EnCana*].
85 *Supra* note 71.
86 *Supra* note 59.
87 [1989] 1 S.C.R. 1722 [*Bell Canada*].
88 *EnCana*, *supra* note 84 at para. 15, quoting from Paramount's Memorandum of Argument at para. 21.
89 *EnCana*, *ibid.* at para. 21.

EnCana's approach was slightly different, arguing that the AEUB had committed an error in limiting the scope of the hearing leading up to Decision 2004-045. The Court had little difficulty disposing with this argument, stating that unless the Board could conduct expedited hearings, its ability to carry out its statutory mandate in time-sensitive situations would be frustrated.

The Court appeared troubled by the mere fact that the multiple affected leave applications brought by gas producers were being made. There was a suggestion by the Court that the stay applications were an attempt to circumvent denials of this remedy by the Court of Appeal in earlier applications. However, the Court did not expand on these concerns, simply indicating that because the test for leave had not been satisfied, the question of a stay need not be decided.

7. *PARAMOUNT ENERGY OPERATING CORP. V. ALBERTA (ENERGY AND UTILITIES BOARD)*[90]

On 2 September 2004 Paperny J.A. of the Alberta Court of Appeal heard the balance of the leave application with respect to Decision 2004-045.[91] The initial application was heard in July 2004, and it was argued that the AEUB lacked jurisdiction for the interim shut-in of wells which resulted from Decision 2004-045. The balance of the grounds of appeal considered by Paperny J.A. were as follows:

(a) bias in that two panel members participated in formulating the policy in GB 2003-028;[92]
(b) the Board failed to disclose its interpretation of evidence prior to making a decision;
(c) the Board failed to adhere to ID 99-1,[93] which set the requirements for gas/bitumen production; and
(d) an absence of reasons.

The Court concluded that because the Phase 3 proceedings were still ongoing, the leave application was premature. The applicant had argued a contrary position premised on the decision of Wittman J.A. in *BP Canada Energy Co.*[94] where leave was granted. The applicant argued that his reasons contemplated that concerns regarding procedural fairness might be dealt with in the interim proceedings. The applicant contended that these fairness issues were not resolved and therefore the present leave application should be granted.

In denying the leave application, the Court noted an appeal of the Board's interim decision would not be dispositive of the Phase 3 proceedings, and that there would be little benefit to sending it back to the AEUB for reconsideration. The concerns of Hunt J.A. with respect to *res judicata* were also repeated by the Court.

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90 (2004), 354 A.R. 375, 2004 ABCA 273.
91 *Supra* note 71.
92 *Supra* note 59.
93 *Supra* note 54.
94 *Supra* note 72.

D. ALBERTA ENVIRONMENTAL APPEAL BOARD

1. *MOUNTAIN VIEW REGIONAL WATER SERVICES COMMISSION V. DIRECTOR, CENTRAL REGION, REGIONAL SERVICES, ALBERTA ENVIRONMENT*[95]

The Alberta Environmental Appeal Board (EAB) was required to consider a decision by the Director, Central Region, Regional Services, Alberta Environment (the Director) to issue Preliminary Certificate No. 00198509-00-00 (the Certificate) and Proposed Licence under the *Water Act*[96] to Capstone Energy Ltd. (Capstone) providing for the allocation to Capstone of fresh water for a secondary recovery project. Once the Proposed Licence was issued and came into effect, it would allow for the diversion of 328,503 m^3 of water annually, at a maximum daily rate of 900 m^3, from the Red Deer River.

The EAB received notices of appeal from the Mountain View Regional Water Services Commission (RWSC), which provides water to a number of municipalities in the Red Deer area. The RWSC was of the view that the EAB should have regard to its three fundamental interests, as follows:

(a) ensuring a sustainable and dependable water supply for the municipalities;
(b) ensuring the water supply was sufficient for continued economic growth; and
(c) preserving the natural environment.

The local agricultural community also presented submissions to the EAB. Their concern was premised on the fact that farmers and ranchers were the project's immediate neighbours, and their livelihood was dependent on a stable supply of water. The EAB noted that the agricultural industry had to deal with water shortage issues over the past number of years.

The EAB stated that this case represented one of the most difficult balancing of interests that had come before it in over ten years of its existence, in that it was being asked to choose between legitimate competing demands for a valuable and finite resource.

The RWSC argued that Capstone's proposal conflicted with Alberta's Water Strategy and was not in the public interest, but rather for the sole benefit of Capstone. It argued that there should have been a more detailed investigation with respect to the alternatives to the water diversion for which Capstone had applied. A further articulated concern was that the Proposed Licence did not contain adequate protection for other water users, including fishermen and other recreational users.

The RWSC referenced the impact of the proposed water diversion on the hydrologic cycle. Generally speaking, the hydrologic cycle is the process whereby water evaporates from oceans, lakes, and streams and is returned to the land as rain or snow. Some of the rain or melted snow will flow over land to a stream channel and be returned to the cycle. Some water will go into the ground through infiltration and will be transpired to the atmosphere, through plants, as vapour. Water in the soil moves downward by the force of gravity, and at

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95 Re: *Capstone Energy* (26 April 2004), Appeal Nos. 03-116 and 03-118-121-R.

96 R.S.A. 2000, c. W-3.

a certain depth, the soil becomes saturated with water. The top of the saturation area is referred to as the water table, containing what is referred to as groundwater. Groundwater can flow through rock and soil until it discharges as a spring or enters upon lake or stream where it again evaporates and the cycle repeats. Water that forms part of the hydrologic cycle is reused, rather than lost.

The RWSC argued that the water injected by Capstone would not be returned to the hydrologic cycle and would be lost forever. It indicated that the volume of water needed by Capstone was the same as that used by the Town of Didsbury, which services 3000 individuals. However, the RWSC asserted that the Town of Didsbury returns 100 percent of this water back to the hydrologic cycle to be used an infinite number of times.

The agricultural community occupies land adjacent to the diversion well. Its interests stemmed from the fact that these lands were used for cattle raising and required a dependable water supply.

The agricultural community submitted that the Director had failed to balance the economic benefits and environmental impacts of the water diversion project, and did not adequately consider the alternatives to the proposed water diversion. The concerns of the RWSC with respect to the removal of water from the hydrologic cycle were echoed by the agricultural community. The effect of the project on both groundwater and surface water on adjacent properties was also raised by the agricultural community. The agricultural community argued that the potential effects of the project on the sloughs and dugouts on landowners' property were not examined, and such formations and structures were important as they were used to contain surface water used by their cattle. The agricultural community further argued that the Director had failed to consider future water use and allocation, along with long-term impacts on the riparian and aquatic environment.

The City of Red Deer also opposed the Proposed Licence, arguing that the Director had failed to comply with not only the specific requirements of the *Water Act*, but also the spirit and intent of that legislation. Like the RWSC and the landowners, the City complained that Capstone had failed to provide sufficient information with respect to the economic impact of the water diversion. As a result, the City argued that the Director was not in a position to evaluate whether the proposal represented a proper allocation and use of water as required by the *Water Act*. It was argued that the needs of municipalities should have a higher standing with respect to water allocation decisions, as municipalities return much of the water used back to the hydrologic cycle, and thus the public interest is better served. The City argued that on its face, the oilfield injection of potable surface water was a bad practice.

Capstone and the Director made submissions in support of the Proposed Licence. The Director took an interesting position, arguing that those who opposed the Certificate and Proposed Licence were attempting to effect policy change, and that the EAB was not the appropriate forum for such a change. The Director took the view that the *Water Act* does not assign priority to the purpose for which water is used, but rather sets out various statutory factors to be considered. The Director pointed out that there was no existing policy or legislation precluding the use of surface water for oilfield injection purposes. It was further asserted that if the municipal use of water were to rank ahead of industrial use, the *Water Act* would need to be amended to accomplish this change.

In addition, the Director made a number of technical arguments related to flow rates and flow volumes.

The EAB concluded that the Proposed Licence should be varied to reduce Capstone's water allocation. The EAB made a number of comments emphasizing the importance of the oil and gas industry to Alberta, and the fact that the industry was undertaking efforts to reduce the use of fresh water. The EAB again characterized its task as being the balancing of the protection of fresh water with ensuring that the oil and gas industry is sustained. The EAB also accepted the view that once fresh water is injected as part of an oilfield recovery injection process, it is lost from the hydrologic cycle for millions of years. As a result of this loss, s. 2 of the *Water Act* mandated that the proposed water diversion receive much greater scrutiny.

The EAB made the following further findings with respect to the application of the *Water Act* to requests for water diversion:

(a) in that the purpose for which water is used is referenced numerous times throughout the *Water Act*, the Director is obligated to take this into account when making licensing decisions;
(b) the fact that the proposed water use is for oilfield injection is not, standing alone, sufficient reason to refuse to grant an allocation of water under the *Water Act*, but rather one of a number of factors the Director must consider;
(c) the Director is obligated to consider the overall economic analysis and appropriateness of the water diversion project, as well as considering alternative sources of water for the proposed project; and
(d) the Director has an obligation to consider alternatives to the proposed water diversion, especially where the water will be effectively lost from the hydrologic cycle.[97]

The EAB then varied the Proposed Licence to reduce Capstone's allocation to 600 m^3/day, for a total allocation of 219,000 m^3 annually. The EAB also recommended that a condition be added requiring Capstone to utilize any alternative water sources, such as produced water, where possible, and to provide the Director with a report setting out a more detailed investigation of alternative water sources.

The EAB further directed that some of the monitoring provisions of the Proposed Licence be varied to require Capstone to provide the Director with a copy of any complaints received by Capstone. The EAB also recommended that the Director be permitted to shut in the diversion well, if necessary, while it investigated and resolved any complaints.

[97] In this case, Capstone was able to satisfy the EAB that carbon dioxide injection was not a viable option. However, the EAB again emphasized s. 2 of the *Water Act*, and stated that fresh water should only be used in this circumstance where there is no other feasible alternative.

IV. LEGISLATIVE DEVELOPMENTS

A. FEDERAL

1. *CANADA OIL AND GAS DRILLING AND PRODUCTION REGULATIONS*[98]

The *Canada Oil and Gas Drilling and Production Regulations* update and re-structure the *Canada Oil and Gas Drilling Regulations*[99] and the *Canada Oil and Gas Production and Conservation Regulations*[100] through consolidation into one regulation. These regulations establish requirements for engineering, safety, and environment and the conservation of resources and pertain to the design, construction, operation, and abandonment of exploration and production facilities under the *Canada Oil and Gas Operations Act.*[101]

These regulations are part of the NEB's efforts, under Smart Regulation, to update and streamline the administration of regulations.

B. ALBERTA

1. *CONSERVATION AND RECLAMATION REGULATION*[102]

Alta. Reg. 131/2004 amends the *Conservation and Reclamation Regulation*[103] associated with the *EPEA.*[104] This regulation adopts the *Code of Practice for Exploration Operations*[105] and the *Code of Practice for Pits.*[106] The *Code of Practice for Exploration Operations* governs the conduct or reclamation of an exploration operation and the *Code of Practice for Pits* governs the construction, operation, or reclamation of a pit listed in the *Activities Designation Regulation.*[107]

2. *PETROLEUM AND NATURAL GAS TENURE REGULATION*[108]

Alta. Reg. 155/2004 amends provisions of the *Petroleum and Natural Gas Tenure Regulation*[109] regarding offset notice periods and compensation (ss. 19-23), and petroleum and natural gas licences (ss. 9-11).

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98 C.R.C. c. 1517.
99 S.O.R./1979-82.
100 S.O.R./1990-791.
101 R.S.C. 1985, c. O-7.
102 Alta. Reg. 131/2004.
103 Alta. Reg. 115/1993.
104 *Supra* note 24.
105 Made under the *EPEA*, *ibid.*, and *Conservation and Reclamation Regulation*, *supra* note 103 (September 2005).
106 Made under the *EPEA*, *ibid.*, and *Conservation and Reclamation Regulation*, *ibid.* (1 September 2004).
107 Alta. Reg. 211/1996.
108 Alta. Reg. 155/2004.
109 Alta. Reg. 263/1997.

3. *CROWN MINERALS REGISTRATION REGULATION*[110]

Alta. Reg. 156/2004 amends the *Crown Minerals Registration Regulation*[111] provisions respecting the registration of statutory declarations to permit the registration of a statutory declaration as provided for in the *Mines and Minerals Act* (ss. 7-9).[112]

4. *OIL AND GAS CONSERVATION REGULATIONS*[113]

Amendments to this regulation[114] pertain to the requirement to provide security and a liability assessment upon an application for an approval for a oilfield waste management facility. The regulation provides that where security or a liability assessment is not provided, the AEUB may direct operations at the facility to be suspended pending the provision of security and/or the liability assessment.

The amount of security to be provided is the total amount of the costs set out in the liability assessment as approved by the AEUB. The Board may use security provided for the suspension, abandonment, site decontamination, or surface land reclamation of an oilfield waste management facility. The Board may also vary the amount of security where the cost of suspending, abandoning, decontaminating the site, or reclaiming the surface land has changed. Where such an adjustment is made, the Board must notify the approval holder of that adjustment.

In addition to the previous circumstances where the AEUB may direct that security be forfeited, the regulation adds the situation where the approval holder fails to commence or complete site decontamination or surface land reclamation in a timely fashion.

5. *NATURAL GAS ROYALTY REGULATION, 2002*[115]

On 6 October 2004, the *Natural Gas Royalty Regulation, 2002*[116] was amended by *Regulation* 225/2004. Section 6(12) was added, allowing the Minister, in determining royalties, to prescribe a quantity of conservation gas for the month for any eligible well event from which no production is recovered during the month, namely in the interval from the top of the Wabiskaw member to the base of the McMurray Formation in the Athabasca Oil Sands Area. Section 19 is amended by adding subsection (7), which provides that when calculating injection credits, no reduction shall be made with respect to conservation gas. Section 21 is amended by adding subsection (3.1), which provides that when calculating deposits made by royalty clients, no reduction shall be made with respect to conservation gas.

110 Alta. Reg. 156/2004.
111 Alta. Reg. 264/1997.
112 R.S.A. 2000, c. M-17.
113 Alta. Reg. 202/2004.
114 *Supra* note 32.
115 Alta. Reg. 225/2004.
116 Alta. Reg. 220/2002.

6. *MINES AND MINERALS ADMINISTRATION REGULATION* [117]

Alta. Reg. 154/2004 amends provisions of the *Mines and Minerals Administration Regulation*[118] respecting trespass (s. 22.1); functional equivalency (ss. 23.1-23.6); fees and penalties (Prescribed Fees and Penalties Schedule); the release of Crown mineral ownership data through the Land Status Automated System; and the release and waiver form for Verbal Surface Searches.

7. *SECURITY MANAGEMENT REGULATION*[119]

This regulation establishes the security measures intended to respond to a threat of terrorist activity for a "critical facility," which means "an oil sands mine, a facility for electrical generation, for gas processing or for oil sands processing, a transmission line, a pipeline or related facility, a petrochemical plant or a refinery named in the critical infrastructure list"[120] established under the Alberta Counter-Terrorism Crisis Management Plan. A licensee of a critical facility must implement an emergency response plan. The regulation also outlines the steps the AEUB must take where a threat of terrorist activity is present.

8. INNOVATIVE ENERGY TECHNOLOGIES REGULATION[121]

Alta. Reg. 250/2004 adds the new *Innovative Energy Technologies Regulation*, the purpose of which is to respond to Alberta's future energy needs by investing in research, technology, and innovation. This regulation allows industry to apply for funding for innovative technologies, providing for up to $200 million in royalty adjustments over five years, intended to offset the cost of implementation of innovative technologies to maximize oil, natural gas, and *in situ* oil sands reserve recovery. The objective of this regulation is to generate long-term royalties from the resulting increased recovery from Alberta oil, gas, and oil sands resources. Participants in this program must have applied prior to the 31 October 2005 deadline. To fulfill the purpose of the program, the resulting technologies will be made available to third parties on reasonable commercial terms.

9. *SPECIFIED GAS REPORTING REGULATION*[122]

Alta. Reg. 251/2004 provides that where a person releases or permits the release of a specified gas at a facility exceeding the Specified Gas Reporting Standard, the person responsible for the facility must submit a specified gas report. The regulation also contains provisions with respect to obligations of specified gas reporters with respect to record keeping, the ability to request confidentiality, and access to a specified gas report. A person responsible who contravenes the regulation is liable to a fine of not more than $50,000 in the case of an individual and not more than $500,000 in the case of a corporation; however, it

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117 Alta. Reg. 154/2004.
118 Alta. Reg. 262/1997.
119 Alta. Reg. 249/2004.
120 *Ibid.*, s. 1(c).
121 Alta. Reg. 250/2004.
122 Alta. Reg. 251/2004.

is a defence that the person took all reasonable steps to prevent the offence or that the data available was insufficient to permit compliance with any reporting period.

C. BRITISH COLUMBIA

1. AMENDMENTS TO THE *UTILITIES COMMISSION ACT*[123]

The relevant amendment to the *Utilities Commission Act* involves s. 2(4), which provides that specific sections of the *Administrative Tribunals Act*[124] apply to the B.C. Utilities Commission. These sections primarily address the rules governing the chair of a tribunal, the general powers of a tribunal to make rules respecting practice and procedure, the effect of a party not complying with tribunal rules or orders, and rules that apply in respect of tribunal proceedings. Section 2(4) provides that a reference to a deputy chair in the *Utilities Commission Act* is a reference to a vice chair under the *Administrative Tribunals Act*.

V. POLICY DEVELOPMENTS

A. FEDERAL

1. SMART REGULATION[125]

In light of the demand for a more effective, responsive, cost-efficient, transparent, and accountable regulatory system, the approach to federal regulation in Canada is to be redesigned through Smart Regulation.

There are three key characteristics of Smart Regulation:

(1) **"Smart Regulation is both protecting and enabling."** Smart Regulation uses the regulatory system to effect social and environmental benefits while promoting a "competitive and innovative economy."

(2) **"Smart Regulation is more responsive regulation."** Smart Regulation acts quickly to prevent risks and enable innovation and opportunity, allowing Canadians to benefit from new knowledge. Provided that high standards and accountability are in place, regulates are given more flexibility in terms of how results may be achieved.

(3) **"Smart Regulation is governing co-operatively for the public interest."** Smart Regulation balances the views of Canadian citizens, the needs of business and the responsibilities of government in a "complex global system."[126]

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

124 S.B.C. 2004, c. 45.

125 Canada, External Advisory Committee on Smart Regulation, *Smart Regulation: A Regulatory Strategy for Canada* (September 2004) (Chair: Gaëtan Lussier).

126 *Ibid.* at 12-13.

Smart Regulation has the following goals:

- support ... Canadian social, environmental and economic priorities;
- achieve high standards of protection for [Canadian] citizens;
- support the transition to sustainable development;
- enhance ... confidence ... in Canada's regulatory system;
- position Canada internationally as a place to do business;
- help Canadians take advantage of new knowledge; and
- make better use of government resources.[127]

To effect these goals, the External Advisory Committee on Smart Regulation (the Committee) was established to provide an external perspective and advice to the federal government.

The Committee's vision is that:

> Governments, citizens and businesses will work together to build a national regulatory system that maximizes the benefits of regulation for all Canadians, enables them to take advantage of new knowledge and supports Canada's participation in an international economy. Within this vision are three components:
>
> TRUST — The regulatory system must instil trust, confidence and credibility at home and abroad in Canadian products and services, markets and government institutions.
>
> INNOVATION — The regulatory system must enhance market performance and support innovation, competitiveness, entrepreneurship and investment in the Canadian economy.
>
> PROTECTION — The regulatory system must demonstrate to citizens that the public interest, which includes such issues as human health and safety and environmental protection, will be safeguarded within dynamic global markets.[128]

The Committee feels that this vision can be achieved through adherence to the following principles:

(1) Effectiveness — Regulation must achieve intended policy objectives, advance national priorities, provide flexibility in serving the public interest, reflect the latest knowledge and be modified when necessary.

(2) Cost-efficiency — Regulatory measures and enforcement should accord with the risks involved to achieve maximum cost-efficiency.

(3) Timeliness — Timelines for regulatory decisions and government services must reflect "the pace at which new knowledge develops, consumer needs evolve and business now operates."

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127 *Ibid.* at 13.
128 *Ibid.* at 14.

(4) Transparency — "[A]ccessibility and transparency of the regulatory system must be maximized to promote learning ... information sharing" and public trust in Canadian regulation.

(5) Accountability and performance — Regulators must announce their intended results and show their progress in achieving those results. "Performance should be monitored, measured and reported on publicly."[129]

The Committee was also mandated with identifying areas of regulation requiring reform. Of particular interest to the energy sector are proposed changes to the environmental assessment process and oil and gas exploration and development.

In terms of environmental assessment, the Committee is proposing a national environmental assessment system that is results-based, timely, predictable, cost-effective, and accessible and is co-ordinated within the federal government and among different jurisdictions.

In terms of oil and gas exploration and development, the Committee feels that regulation of the upstream oil and gas sector should allow for development in a manner that is environmentally sustainable while enabling an economically competitive and innovative industry.

B. ALBERTA ENERGY AND UTILITIES BOARD

1. GUIDE 31(B): GUIDELINES FOR UTILITY COST CLAIMS[130]

Guide 31(B) identifies circumstances in which the AEUB may award participants in a utility proceeding the reasonable costs associated with their involvement. Where the Board finds that an intervener's participation is premised solely on the protection of its business interests, it may be required to bear some or all of the costs of its participation in the proceeding. Where a party requests a review of a hearing that is denied on the preliminary question, it will be required to bear its own costs associated with that review.

2. DIRECTIVE 006: LICENSEE LIABILITY RATING (LLR) PROGRAM AND LICENCE TRANSFER PROCESS[131] AND DIRECTIVE 011: LICENSEE LIABILITY RATING (LLR) PROGRAM UPDATED INDUSTRY PARAMETERS AND LIABILITY COSTS[132]

Through the rescinding of the following Interim Directives and Guides, Directive 006 amends and consolidates the rules applicable to the LLR Program and Licence Transfer Application as follows:

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129 *Ibid.* at 14-15.
130 January 2004.
131 1 June 2004.
132 1 June 2004.

(a) ID 2000-09: Notification Requirements for the Discontinuation and Abandonment of Pipelines and the Abandonment of Facilities (24 October 2000);

(b) ID 2000-11: Energy Development Licence Transfer Requirements and Monthly Corporate Licensee Liability Rating (24 October 2000);

(c) ID 2000-11 Amendment: Interim Energy Development Licence Transfer Requirements and Monthly Corporate Licensee Liability Rating (12 April 2001);

(d) ID 2001-6: Electronic Submission of Licence Transfer Applications, Well Name Change Notifications, Facility Abandonment Notifications, and Linked Facility Notifications (19 October 2001);

(e) ID 2001-8: Revised Licensee Liability Rating (LLR) Program and Energy Development Licence Transfer Requirements (4 December 2001);

(f) Guide 69: Energy Development Licence Transfer (October 2000);

(g) GB 2002-3: Licensee Liability Rating (LLR) Implementation (2 April 2002);

(h) GB 2003-03: Licensee Liability Rating (LLR) Program; 2003 Industry Parameters and Clarification of Requirements (28 January 2003);

(i) GB 2003-10: Licensee Liability Rating (LLR) Program 2003 Industry Parameters, Return of Unaccepted Licence Transfer Applications (1 April 2003); and

(j) IL 2000-4: Replacement of the Long-Term Inactive Well Program with the Monthly Corporate Licensee Liability Rating (24 October 2000).

Directive 006 does not make any major changes to the above rules.

Directive 011 deals with updated deemed asset and liability parameters used by the AEUB to calculate the LLR. The Board has phased in payment of any additional security deposit requirements resulting from the new parameters, with one half of the increased security deposit due 2 July 2004 and the balance due on 3 June 2005.

3. DIRECTIVE 013: SUSPENSION REQUIREMENTS FOR WELLS[133]

Directive 013 establishes requirements for the suspension of inactive wells. The objectives of this directive are to ensure continued public safety, environmental protection, and resource conservation at inactive wells and to consider appropriate risk factors in formulating well suspension requirements.

[133] 1 December 2004.

4. DIRECTIVE 016: UTILITY REGULATORY AUDITS AND REVIEWS[134]

Directive 016 outlines the legislative authority for regulatory audits and sets out the work to be carried out by the Audit and Compliance Group of the Utilities Branch when conducting regulatory audits. It also outlines the AEUB's objectives for conducting regulatory audits and provides information with respect to the treatment of information obtained or generated by the Audit and Compliance Group during the course of an audit. Independent and objective third-party reviews of utility finances and operations are to be made available to the public by the Board.

5. DIRECTIVE 036: DRILLING BLOWOUT PREVENTION REQUIREMENTS AND PROCEDURES[135]

The purpose of this directive is to update the AEUB's minimum requirements regarding blowout prevention equipment and procedures for drilling wells. This directive replaces ss. 8.130 to 8.143 and Schedule 8 of the *OGCR*[136] and eliminates or modifies eight existing interim directives, general bulletins, and informational letters that relate to drilling operations.[137]

6. DIRECTIVE 065: RESOURCES APPLICATIONS FOR CONVENTIONAL OIL AND GAS RESERVOIRS[138]

Directive 065 simplifies the process for obtaining the necessary approvals from the Board to establish a strategy to deplete a pool by imposing a new set of requirements for all Enhanced Recovery (ER) scheme applications and eliminating Enhanced Recovery Recognition and Project Status applications.

To ensure the optimization of hydrocarbon recovery and that all ER scheme requirements are met, the Board will now review all ER scheme applications. ER scheme applications meeting the Directive 065 criteria will be processed in an expedited manner under a quick ER application process.

The Board will now audit all ER schemes approximately six months after approval or approval amendment.

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134 26 January 2005.
135 June 2004, 2d ed., incorporating Revision 1, Errata, 20 July 2004.
136 *Supra* note 32.
137 See AEUB, Bulletin 2004-18: "Directive 036: Drilling Blowout Prevention Requirements and Procedures" (5 July 2004).
138 30 November 2004, incorporating Revision 1, 14 December 2004 (Appendix H).