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

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The authors canvass important regulatory decisions and legislative developments during the period April 2001 to mid-May 2002.

Les auteurs examinent à fond les décisions réglementaires importantes et les développements législatifs pris entre avril 2001 et la mi-mai 2002.

TABLE OF CONTENTS

I. INTRODUCTION 189
II. REGULATORY DEVELOPMENTS 190
A. NATIONAL ENERGY BOARD 190
B. ALBERTA ENERGY AND UTILITIES BOARD 203
C. CANADA-NEWFOUNDLAND OFFSHORE PETROLEUM BOARD 224
D. ARBITRATION BETWEEN NEWFOUNDLAND AND LABRADOR AND NOVA SCOTIA CONCERNING PORTIONS OF THE LIMITS OF THEIR OFFSHORE AREAS: AWARD OF THE TRIBUNAL IN THE SECOND PHASE 228
III. LEGISLATIVE DEVELOPMENTS 229
A. FEDERAL LEGISLATION 229
B. ALBERTA LEGISLATION 231
C. BRITISH COLUMBIA LEGISLATION 233
D. SASKATCHEWAN LEGISLATION 234
E. NOVA SCOTIA LEGISLATION 236
F. NEW BRUNSWICK LEGISLATION 236
G. NEWFOUNDLAND LEGISLATION 236
IV. POLICIES, DIRECTIVES AND GUIDELINES 237
A. NATIONAL ENERGY BOARD 237
B. NORTHERN PIPELINE ENVIRONMENTAL IMPACT ASSESSMENT AND REGULATORY CHAIRS COMMITTEE 239
C. ALBERTA ENERGY AND UTILITIES BOARD 240

I. INTRODUCTION

This article identifies and discusses significant regulatory decisions, legislative developments and regulatory policy developments which have occurred across the country from April 2001 to mid-May 2002. Part II contains a discussion of recent regulatory decisions, with a focus on the National Energy Board (NEB) and the Alberta Energy and Utilities Board (AEUB). Commentary is also provided on certain decisions emanating from the Maritimes. Part III identifies recent federal and provincial statutory amendments and proposed amendments which may impact the oil and gas industry. Part IV identifies recent regulatory policy developments implemented by the NEB and the AEUB.

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Between April 2001 and mid-May 2002 the NEB has addressed a number of tolling matters, including negotiated settlements, tolling methodology and the prospective consideration of tolls relating to future pipeline projects. Tolling was also a topic before the AEUB in the context of a negotiated settlement and the continued evolution of the intra-Alberta gas transportation market. On the upstream end, the AEUB continued to address public consultation, gas/bitumen and jurisdictional matters. Developments in the Maritimes saw approval of the White Rose project and establishment of the offshore boundary between Nova Scotia and Newfoundland.

In preparing this article, the authors have not attempted to report on all regulatory matters emanating from all Canadian jurisdictions, nor have we attempted to produce comprehensive briefs for those regulatory decisions, statutory amendments and policy developments identified in this article. Rather, our goal has been to focus on recent significant developments of which oil and gas lawyers should be aware, and which they will hopefully find interesting.

II. REGULATORY DEVELOPMENTS

A. NATIONAL ENERGY BOARD

1. RH-3-2001: *Maritimes & Northeast Pipeline Management, Application for Final Tolls and Phase 2* [1]

RH-3-2001 started out as a fairly typical rate hearing. It ended up, however, with the NEB willing to consider tolling matters not for the original applicant, but rather for a hypothetical pipeline project.

On 23 March 2001, Maritimes & Northeast Pipeline Management (M&NP) filed an application seeking approval of its rate base, revenue requirement and deferral accounts for the 2001 and 2002 test periods. On 16 July 2001, the NEB, in its usual practice, issued Hearing Order RH-3-2001 with its Preliminary List of Issues. On 1 August 2001, a joint submission[2] was made to the NEB requesting that the following issue be added as issue four:

> As it applies to new pipeline facilities, the proper application and interpretation of Article 17 of the general terms and conditions of Maritimes and Northeast Gas Tariff (the Article 17 issue).[3]

Article 17 of M&NP's tariff is its Lateral Policy and provides:

> 17.1 Customers may request that [M&NP] construct a pipeline extension (other than a mainline extension) from [M&NP's] existing facilities to deliver gas to one or more Customers, including new delivery points and enlargements or replacements of existing laterals.... In the event [that M&NP] decides to construct such

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1 *Reasons for Decision on the Article 17 Issue* (8 November 2001), RH-3-2001 (NEB) [Article 17 Decision].

2 Cartier Pipeline & Company, Limited Partnership (Cartier), Societe en Commandite Gaz Metropolitain, The Consumers Gas Company, carrying on business as Enbridge Consumers Gas, Enbridge Gas New Brunswick and the Minister of Natural Resources and Energy of the Province of New Brunswick (the JS Group).

3 *Supra* note 1 at 1.

> facilities and the contracted demand requested by a Customer generates sufficient revenue each year, based on a test toll of $0.60/MMBtu ($0.5687/GJ) designed to maintain the competitiveness of [M&NP's] tolls, to recover the annual cost of service associated with the incremental capital and operating cost of the facilities, [M&NP] will proceed to construct the facilities without any contribution of the customer.... If the facilities do not generate sufficient revenue to cover the cost of service associated therewith, [M&NP] will require a Customer contribution.[4]

If the Lateral Policy applied, a Customer Contribution would be calculated using a cost of service methodology, with the customer paying the difference between the cost of the requested facilities and revenue generated under the $0.60/MMBtu test toll. The contribution would only be payable for the period during which the test toll revenues on the lateral resulted in a shortfall. On 13 August 2001, the NEB amended the Issues List to include the Article 17 issue.

On 14 September 2001, M&NP submitted to the NEB a settlement compliance filing, which addressed all issues except Article 17 matters. That settlement involved participation by M&NP's Tariffs and Tolls Working Group (TTWG), but did not include the Union of New Brunswick Indians (UNBI). The UNBI opposed the settlement based on objections relating to socio-economic benefits for Aboriginal peoples and their non-inclusion in the regulatory process, including the settlement negotiations. In its submissions, the UNBI asserted Aboriginal title and an interest in the land and resources of the province.

By way of letter dated 14 November 2001, the NEB issued its decision regarding M&NP's settlement compliance filing. The NEB held that the issues raised by the UNBI were not directly related to the issues before the NEB in RH-3-2001. Further, the RH-3-2001 proceeding was not considered the appropriate forum to address questions of Aboriginal interest and title, and such matters were beyond the NEB's jurisdiction under Part IV of the *National Energy Board Act*.[5] The NEB approved the settlement and indicated that the benefits of the settlement outweighed the objections raised by the UNBI. Further, the UNBI was encouraged to participate in the TTWG so that its issues could be dealt with outside of the hearing process.

The only remaining issue was that of the application of Article 17, which involved the hypothetical "Northwest Facilities." The Northwest Facilities comprised approximately 260 kilometres of pipeline which would extend from an interconnection with the proposed Cartier pipeline at the New Brunswick/Quebec border through northwestern New Brunswick to M&NP's existing mainline near Fredericton.[6]

The issue before the NEB was whether Article 17 would apply to the Northwest Facilities. Article 17 would only apply if those hypothetical facilities were considered to be a "lateral" and not a "mainline extension."

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4 National Energy Board, Gas Tariff, Maritimes and Northwest Pipeline Limited Partnership, Art. 17.1 at Sheet No. 238.

5 R.S.C. 1985, c. N-7 [*NEBA*]. Part IV deals with Traffic, Tolls and Tariffs.

6 Article 17 Decision, *supra* note 1 at 1-2.

The JS Group argued in their joint submission that the Article 17 issue affected the overall viability of the combined project comprising Cartier pipeline to the New Brunswick border and the Northwest Facilities. Further, it was of critical importance that the market know the cost of transporting gas from the Maritimes to markets in central Canada and the United States. Dealing with the Article 17 issue would not result in significant delay and it would actually save time and money. Also contained in the joint submission were a series of questions to M&NP regarding the Article 17 issue.

Following the inclusion of the Article 17 issue by the NEB, parties made submissions respecting the scope of matters to be addressed. The East Coast Producers Group (ECPG) and M&NP opposed the inclusion of the Article 17 issue. Their opposition was based on the added time, expense and delay it would cause, as well as relevance. They argued that the Article 17 issue was not relevant to a tolls hearing that was to deal with the test years 2001 and 2002. The ECPG submitted that the JS Group was in effect seeking relief for itself with respect to a pipeline that would not be in service until 2004, two years after the end of the 2002 test period. Following these preliminary arguments, two very different interpretations of the scope of the Article 17 issue developed.

Following the filing of evidence by intervenors, which included evidence relating to tolling methodology for the Northwest Facilities, on 18 September 2001 M&NP filed a motion to strike portions of that evidence. M&NP sought to strike the portions of the evidence filed on behalf of certain members of the JS Group that M&NP felt was beyond the scope of the Article 17 issue. M&NP indicated that its understanding of the Article 17 issue was that the issue covered no more than the interpretation of Article 17 and its applicability to new pipeline facilities. M&NP asserted that the impugned evidence dealt with matters that would arise in the event that Article 17 did not apply. The NEB, in a letter dated 21 September 2002, ruled that the evidence would be beneficial to the proceeding and that the NEB would solicit submissions from parties on the relevance of the evidence during final argument. The NEB's 21 September letter generated considerable comment from parties on both sides of this issue. Several parties indicated that they opposed the NEB's ruling that evidence relating to the appropriate tolling treatment on the Northwest Facilities should be permitted.

Several parties also expressed concern that dealing with the appropriate tolling methodology on the Northwest Facilities went beyond their understanding of the Article 17 issue. Further, procedural fairness concerns were raised based on the argument that the original public notice did not include the Article 17 issue, especially in a form which might deal with appropriate tolling methodology on the Northwest Facilities. Parties had made decisions on whether or not to intervene in the proceedings based on an Issues List that was very different from the one that developed through the course of the proceedings.

As a result of these submissions, the NEB clarified the scope of the Article 17 issue in a letter dated 3 October 2001, stating that it "had not decided to 'hear evidence relating to the general toll treatment of the Northwest Facilities in the event Article 17 does not apply.' Rather, the Board had left it open to parties to suggest that the evidence subject to the Board

Rulings may have some relevance to the interpretation of Article 17 itself."[7] The NEB held that its consideration of the Article 17 issue specifically did not include the following:

- tolls for Northwest Facilities, or other specific facilities;
- toll methodology for Northwest Facilities or other specific facilities;
- joint hearing on the Combined Project and any other application to expand the M&NP system;
- economic feasibility of the Northwest Facilities, or any other specific facilities;
- matters related to a *National Energy Board Act* section 52 determination, including supply and markets; and
- tolls on TQM, TCPL as a result of the addition of any new facilities or tolls for the Combined Project.[8]

The NEB indicated that it would be willing to deal with the issue of appropriate tolls for the Northwest Facilities by establishing a separate process treating Cartier as the applicant. In that event, it would be appropriate to provide Cartier with an opportunity to file sufficient evidence.

Following an oral hearing, the NEB rendered reasons for decision on the Article 17 issue by letter dated 8 November 2001. The question before the NEB was whether the Northwest Facilities were a lateral, in which case Article 17 would apply, or a mainline extension. In order to determine that question, the NEB had to determine the meanings of "lateral" and "mainline extension," as neither of those terms were defined in the M&NP tariff. To do so, the NEB looked at the context and intent of the Lateral Policy. The NEB found that the intent of rolling-in costs for laterals was to encourage the development of gas markets in the Maritimes by allowing local markets the potential to obtain gas at significantly less cost than if a separate distribution system was established to serve those markets. The NEB decided that "the application of the Lateral Policy, with its potential for subsidization of gas service in the Maritimes, should be limited to cases clearly contemplated by the joint panel."[9]

The NEB then considered whether the Northwest Facilities were consistent with the Lateral Policy. The NEB noted that:

- approximately 90% of the throughput from the Northwest Facilities will be exported from the Maritimes;
- those export target markets, for the most part, are already served by natural gas infrastructure;
- the Northwest Facilities would connect to existing markets through the Cartier pipeline, TQM, and the TransCanada system;
- the Northwest Facilities would likely be physically integrated with the rest of the M&NP system;
- all shippers could use the Northwest Facilities;
- all shippers who use the Northwest Facilities would use M&NP's upstream facilities;
- the same services would be offered on the Northwest Facilities as on M&NP's mainline;
- compared with the lateral facilities constructed to date, the Northwest Facilities would be larger and many times more costly; and

7 *M&NP Proposal for Separate Process — Clarification of Procedural Rulings* (Board Letter) (3 October 2001), RH-3-2001 at 2 (NEB).

8 *Ibid.*

9 Article 17 Decision, *supra* note 1 at 6. See also Joint Public Review Panel Report: Sable Gas Projects (October 1997) at 69-70.

- in theory, the Northwest Facilities could compete with the existing M&NP system.[10]

In the NEB's view, this was clear evidence that the physical and functional characteristics of the Northwest Facilities were significantly different from those of any laterals constructed in the Maritimes. The NEB held as follows:

> It would be a stretch of logic to apply the Lateral Policy, with its potential for subsidization, to such facilities.
>
> ...
>
> In summary, it is the Board's view that the Northwest Facilities are a mainline extension, as that term is used in Article 17 and not a lateral, and are not facilities to which the benefits of the Lateral Policy were intended to apply. Accordingly, the Northwest facilities fall outside the ambit of Article 17.[11]

The NEB made it clear that because hypothetical pipeline facilities were being considered, its reasons for decision would be applicable only insofar as future facilities were materially similar to the hypothetical facilities that were considered in the RH-3-2001 proceedings.

Phase 2 of the RH-3-2001 proceeding commenced with the NEB inviting Cartier to file submissions regarding tolling treatment on the Northwest Facilities if it wished to proceed as an applicant in that matter. On 10 October 2001, Cartier indicated that it wished to proceed on that basis and subsequently filed submissions respecting the appropriate toll treatment of the Northwest Facilities on 30 November 2001. The NEB issued Hearing Order RH-3-2001, Phase 2 on 15 January 2002. On 28 January 2002, the Canadian Association of Petroleum Producers (CAPP) applied to the NEB for a review and variance of Hearing Order RH-3-2001, Phase 2. CAPP also requested a stay of the application, pending the outcome of its review application. As well, M&NP filed a motion in the Federal Court of Appeal on 14 February 2002, requesting leave to appeal Hearing Order RH-3-2001, Phase 2.

On 19 February 2002, Cartier requested that the NEB terminate the RH-3-2001, Phase 2 proceeding by rescinding the Hearing Order. Cartier indicated that it did not intend to abandon its project, but the urgency had been tempered by a number of factors, including confirmation by PanCanadian Energy Corporation that gas from the Deep Panuke project was dedicated to export markets, downgrades of gas reserve estimates for the Sable Offshore Energy Project by Shell Canada and opposition by CAPP and the ECPG. Cartier expressed the desire to revisit issues related to the Northwest Facilities at a later date in a more favourable business environment.

2. GH-3-2001: *PETRO-CANADA, MEDICINE HAT PIPELINE*[12]

GH-3-2001 involved an application for the Medicine Hat Pipeline which would bypass the NOVA Gas Transmission Limited (NGTL) system at the Alberta–Saskatchewan border. The NEB, in approving the application, continued to let the market determine whether bypass pipeline projects proceed.

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[10] *Ibid.* at 6.

[11] *Ibid.* at 6-7.

[12] *Petro-Canada, Medicine Hat Pipeline* (December 2001), GH-3-201 (NEB).

On 25 July 2001, Petro-Canada applied under s. 52 of the *NEBA* for a 71.3 kilometre sweet gas pipeline running from Petro-Canada's Medicine Hat 3A compressor station to an interconnect with TransCanada Pipelines Limited's meter station near Burstall, Saskatchewan. Also applied for were four laterals and related facilities.

Two issues considered at the hearing were "markets and transportation contracts" and "economic feasibility." Petro-Canada indicated that it would be able to supply the pipeline from five producing properties in the Medicine Hat area and was prepared to pay for the entire pipeline. In response, NGTL took the position that the Medicine Hat Pipeline was different from other bypass pipelines because there were no long-term transportation contracts supporting the project. Consequently, the NEB would not have evidence that it had traditionally considered respecting whether the proposed pipeline would be used at a reasonable level and demand charges paid for over its economic life. The NEB concluded that the Medicine Hat Pipeline would supply markets in eastern Canada and the United States. Further, because it expected to see growth in those markets, the NEB found that the Medicine Hat Pipeline was likely to have reasonable markets and be used at a reasonable capacity over its life.

The NEB noted that Petro-Canada had diligently explored alternatives to the Medicine Hat Pipeline. Petro-Canada evaluated shipping on the Alberta Energy Company (AEC) South Suffield pipeline, which itself was a bypass of NGTL,[13] as well as continuing to ship on the NGTL system under a load retention service rule and purchasing the NGTL facilities. The Medicine Hat Pipeline would save Petro-Canada up to $4.7 million per year over continuing to ship on NGTL and up to $600,000 per year plus $3.7 million incremental capital costs over shipping on AEC. The NEB held that "the public interest will be served by the Medicine Hat Pipeline by lowering transportation costs, the benefits of which will not only accrue to Petro-Canada and any third parties selling their gas to the Applicant, but also to the region as a whole."[14]

3. RH-1-2001: *TRANSCANADA PIPELINES LIMITED 2001/2002, TOLLS AND TARIFF*[15]

On 3 May 2001, TransCanada Pipelines Limited (TCPL) filed an application for 2001/2002 tolls and tariffs after an unsuccessful attempt at reaching a unanimous negotiated settlement. Stakeholders representing all but approximately seven percent of annual mainline revenue agreed to the proposed settlement known as the Mainline Service and Pricing Settlement (S&P Settlement). Accordingly, TCPL was required to make a formal toll application to the NEB because the S&P Settlement was not unanimous as required by the NEB's *Guidelines for Negotiated Settlements of Traffic Tolls and Tariffs*, dated 23 August 1994.[16]

Notwithstanding the lack of unanimity, TCPL's application was based on the S&P Settlement. The NEB held that:

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13. *AEC Suffield Gas Pipeline* (July 1998), GH-2-98 (NEB).
14. *Supra* note 12 at 17.
15. *TransCanada Pipelines Limited, 2001 and 2002 Tolls and Tariff Application* (November 2002), RH-1-2001 (NEB).
16. File 4600-A000-3 (NEB).

> while some parties did not support the S&P settlement, all parties had a fair opportunity to participate in a negotiation process. Further, the Board recognizes that the S&P settlement received significant support from a broad cross section of TransCanada's stakeholders. For these reasons, the Board believes that it should give significant weight to the level of support accorded by stakeholders to the S&P settlement.[17]

The NEB indicated that there would be revisions to the settlement guidelines to address contested settlements (see Part IV.A.3 below).

Two other interesting issues addressed by the NEB in RH-1-2001 were the risk faced by TCPL due to decontracting and TCPL's proposed new service enhancements.

In 2001 TCPL was facing declining firm contract volumes on its mainline system. In 1999 and 2000 its volumes were down by 18 percent of total through-put. Exacerbating the situation was the fact that effective 1 November 2001 an additional 133,069 GJ/day of firm contracts were not being renewed and a further 910,926 GJ/day of firm contracts were up for renewal in 2002. TCPL proposed to continue its cost of service model to allocate its revenue requirements. In doing so, its customers would bear increased unit costs due to declining volumes.

The Cogenerators Alliance (CA) proposed a revenue shortfall sharing mechanism wherein each stakeholder would bear a portion of the shortfall in revenue due to decontracting. The scheme would see TCPL responsible for revenue shortfall related to return and associated income taxes (approximately 48 percent). Remaining customers would bear the shortfall associated with unavoidable costs (approximately 35 percent). Departing customers would bear that portion of revenue shortfall associated with the return of capital (approximately 17 percent). The plan would be implemented through stranded cost surcharges and exit fees. The CA also suggested that there be a five- to six-year transition period, after which TCPL would be responsible for 100 percent of the shortfall due to decontracting.

Pacific Gas and Electric Energy Trading and El Paso Merchant Energy Group (PG&E/El Paso) proposed an alternative methodology involving sharing in "2001 and 2002 of the revenue requirement impact of contract non-renewals in 2000, 2001 and 2002. Specifically, TCPL's billing determinants for each test year would be reduced by 50% of the cumulative decontracted units."[18]

The CA and PG&E/El Paso took the position that TCPL had not done all that it could do to be competitive in the market. PG&E/El Paso also took the position that TCPL had been aware of increasing competition, yet went ahead with expansion of its mainline system. The CA and PG&E/El Paso pointed to examples in the United States where pipelines were expected to take on more of the decontracting risk, as well as a more active role in pursuing new markets.

TCPL's position was that excess capacity was due to the entrance of Alliance Pipeline and Vector Pipeline into the market. Further, TCPL argued that it had been prudent in sizing its

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17 *Supra* note 15 at 26.

18 *Ibid.* at 8.

mainline system expansions and, contrary to PG&E/El Paso's suggestion, that it did not have an alternative to its 1999 system expansion, as construction was already underway when it became apparent that there would be increased available capacity due to the Alliance and Vector pipelines.

The NEB recognized that non-renewal of contracts was a significant problem faced by TCPL. It found that there was no clear indication that TCPL had been imprudent or that its actions had caused non-renewals, and the NEB was "not inclined to impose, after the fact, the financial impact of the realization of the risk that TransCanada has not traditionally borne."[19] It indicated that some sharing of risk may be appropriate if it is done on a prospective basis. The NEB rejected the CA and PG&E/El Paso proposals as neither party assessed the impact that its proposal would have on TCPL's ability to manage its risk, long-term viability or cost of capital.[20] The NEB also held that the comparison with American examples was not appropriate, as the Federal Energy Regulatory Commission cases involved pipelines and shippers that had reached agreements regarding risk in advance. The American regulatory precedents supported the notion that there should be some symmetry between the risk that pipelines accept and the tools they have at their disposal to manage that risk. The NEB indicated that reform is required to address the issue of decontracting. It expects pipelines and shippers to negotiate agreements in order to deal with the costs associated with non-renewal of firm transportation contracts.

A second issue addressed by the NEB was TCPL's proposed new service enhancements to firm transportation (FT). The enhancements proposed to FT service were make-up credits and authorized overrun service (AOS) credits. Under the make-up credit proposal, an FT shipper would be given a monthly credit towards interruptible transportation (IT) service based on the aggregate unutilized portion of its FT capacity. The AOS credit proposal would see four percent of a FT shipper's aggregate monthly FT demand charge credited towards that shipper's aggregate IT service monthly invoice. Neither type of credit can be carried forward from month to month, and they are non-refundable.

TCPL's proposed enhancements would lead to slightly higher FT tolls and lower IT tolls, thus benefiting only those FT shippers that also utilize IT service. Nevertheless, the NEB found that the new services would give additional value to FT contracts and increase flexibility for customers. It also found that the new measures were not unduly discriminatory as it was not possible to have enhancements that would apply to all shippers equally. In the result, the NEB approved the S&P Settlement in its entirety.

4. RH-2-2001: *B.C. GAS UTILITY (B.C. GAS), REVIEW OF REASONS FOR DECISION RH-2-98*[21]

RH-2-2001 is an example of the NEB's willingness, in certain appropriate circumstances, to address tolling matters in advance of facilities being constructed (see Part II.A.1 above).

19 *Ibid.* at 13.

20 *Ibid.* at 14.

21 *B.C. Gas Utility Ltd., Application dated May 2001 for certain orders pursuant to subsection 21(1) of the National Energy Board Act* (October 2001), RH-2-2001 (NEB).

In this case, B.C. Gas Utility Ltd. (B.C. Gas) sought a review of the NEB's decision in RH-2-98,[22] which established full zonal tolls for service on the Westcoast Energy Inc. (WEI) system from Kingsvale to Huntingdon, B.C.[23] B.C. Gas specifically sought, among other things, point-to-point tolls based on distance and volume for firm service on WEI, both from Kingsvale to Huntingdon and from Hope to Huntingdon. B.C. Gas also sought an order from the NEB directing WEI to include an incremental 105 MMcf/d capacity on the WEI system from Kingsvale to Huntingdon in its facilities expansion application to accommodate the B.C. Gas volumes.

B.C. Gas's interest in having RH-2-98 reviewed stemmed from its desire to transport gas from the Southern Crossing Pipeline at Oliver, B.C. to Huntingdon. B.C. Gas was interested in assessing the tolls relating to its Inland Pacific Connector pipeline project (the IPC Pipeline). Depending upon downstream tolls on the WEI system, the IPC Pipeline could connect Oliver, B.C. to Hope or Huntingdon. Alternatively, volumes could be transported on B.C. Gas's existing system from Oliver to Kingsvale, where it would then be transported on the WEI system to Huntingdon.

B.C. Gas argued that the grounds for review and variance of RH-2-98 were changed circumstances in the natural gas market. There was increased demand for pipeline capacity in the lower mainland for gas destined for American markets. The NEB held that the changed circumstances did support a review of RH-2-98.[24]

With respect to the Kingsvale to Huntingdon toll, the NEB noted that this application was not an opportunity to conduct a broad examination of WEI's tolling principles:

> Clearly, a broad-based review of tolls is preferable to a piecemeal approach whereby individual shippers file separate applications seeking more favourable toll treatment. Such an approach would frustrate [WEI's] consultative process currently underway to address tolls on a generic basis and could result in a series of individual decisions. At the same time, the Board recognizes that B.C. Gas needs a signal regarding the costs of shipping gas from Kingsvale to Huntingdon in order to make important business decisions. In reaching its decision, the Board has borne these two competing interests in mind.[25]

The NEB held that B.C. Gas's proposed point-to-point toll of 5¢/Mcf for service from Kingsvale to Huntingdon would not compensate WEI for the cost of providing that service and, as a consequence, other shippers would bear some of those costs. In addition, because transportation between Kingsvale and Huntingdon would not be possible unless the WEI system expansion was in place, it would not be fair for B.C. Gas to have a 5¢ toll while other shippers would have increased costs to fund that expansion. The NEB noted, however, that the Zone 4 (Station 2 to Huntingdon) toll of 26¢/Mcf approved in RH-2-98 was based on the now outdated assumption that the facilities north of Kingsvale might be underutilitized. As

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22 N.E.B., *In the Matter of B.C. Gas Utility Ltd.*, No. RH-2-98 (April 1999).

23 The NEB determined in RH-2-98 that a full zonal toll was appropriate at that time due to risk of stranded capacity on WEI's T-South line north of Kingsvale if B.C. Gas connected its Southern Crossing project to the WEI system at Kingsvale. RH-2-98 did not establish tolls for Hope to Huntingdon B.C.

24 *Supra* note 21.

25 *Ibid.* at 10.

that risk had been reduced, the NEB approved WEI's proposed 12¢/Mcf toll for Kingsvale to Huntingdon. The 12¢ toll only applied to contracted volumes following the 105 MMcfd expansion of the WEI system. Until that time, the existing Zone 4 toll applied.

A second issue considered by the NEB involved WEI's concern that B.C. Gas might decontract capacity in Zone 4. WEI offered to construct 105 MMcfd of capacity from Kingsvale to Huntingdon if, among other things, B.C. Gas agreed to "term up" existing contracts for five years. The NEB held that it was appropriate to order B.C. Gas to term up its contacts. Further, the issue of contract terms will be revisited when the application for the new facilities is heard and prior to the 12¢ toll going into effect.[26]

With respect to B.C. Gas's request for a Hope to Huntingdon toll, the NEB held that:

> For the same reasons as described above [regarding the requested Kingsvale to Huntingdon toll], the Board does not believe that a point-to-point toll is appropriate for Hope to Huntingdon service at this time. In the Board's view, it would not be appropriate to undertake a piecemeal approach to tolling while a comprehensive toll design study is underway. Further, the Board agrees with Westcoast and EUG that a toll decision for service between Hope and Huntingdon is premature, given that the specifics of the IPC project are not known with certainty.[27]

In the result, the NEB set a point-to-point toll for Kingsvale to Huntingdon which only required incremental capacity on the WEI system. In contrast, the NEB did not determine a point-to-point toll for Hope to Huntingdon, which would have required a greenfield pipeline (IPC Pipeline), sufficient details of which were not before the NEB.

5. *MURPHY OIL COMPANY: COMPLAINT BY BOW RIVER SOUTH GROUP CONCERNING TOLLS CHARGED ON THE MILK RIVER PIPELINE*[28]

This NEB decision arose out of a complaint dated 25 August 2000, filed by the Bow River South Group (BRS),[29] requesting an examination of the tolls charged on the Milk River Pipeline. The Milk River Pipeline is regulated by the NEB as a Group 2 Company; as such, its tolls are regulated on a complaint basis. During the proceeding, the Milk River Pipeline was sold by Murphy Oil Company (Murphy) to Plains Marketing Canada LP. It should be noted that the NEB continued to refer to the owner of the pipeline as Murphy throughout its Reasons for Decision.

On 31 August 2001, the NEB issued Order No. TOI-1-2000 authorizing Murphy's existing tolls to be charged on an interim basis. The NEB went on, in a written proceeding, to

26 *Ibid.* at 12. See also Part II.A.3 for a discussion of the NEB's consideration of decontracting on the TCPL system.

27 *Ibid.* at 13.

28 *Murphy Oil Company (now Plains Marketing Canada, L.P.), Complaint dated 25 August 2000 by PanCanadian Petroleum Limited, Alberta Energy Company Ltd., Gulf Canada (previously Crestar Energy Inc.) and EOTT Energy Canada Limited Partnership, collectively known as the Bow River South Group (BRS), Concerning Tolls Charged on the Milk River Pipeline* (August 2001), (NEB) [*Murphy Oil*].

29 The BRS consisted of PanCanadian Petroleum, Alberta Energy Company, Crestar Energy and EOTT Energy Canada.

consider a number of issues relating to Murphy's tolls, including competition, rate-base methodology, cost of capital and toll structure. With respect to competition, BRS claimed that Murphy had not altered its tolls for many years despite increases in throughput and theoretical reductions in its rate base. Further, there were no economically competitive alternatives to the Milk River Pipeline for crude oil flowing south to Montana, and as a result Murphy was able to charge excessive rates of return and unreasonable tolls.

The NEB held that the purpose behind economic regulation is to ensure that a company operating in a monopolistic environment does not exercise market power by charging unreasonable rates. In the present case, it indicated that:

> The evidence demonstrates that competing pipelines cannot access 30%-40% of the volumes available to the Milk River Pipeline.... Furthermore, the evidence shows that between 22% and 33% of the total Bow River volume transported on the Milk River Pipeline was from the Fincastle "locked-south" area ... which has no option but to travel south into the Milk River Pipeline.[30]

The NEB noted that the Milk River Pipeline's throughput and earnings had been steadily increasing while tolls had remained the same. It consequently held that the Milk River Pipeline exercised some degree of market power, thus warranting an examination of its tolls.

Regarding the issue of rate base, using a semi-depreciated rate-base methodology, Murphy calculated its 2001 rate base at $10,025,966. The NEB held that a semi-depreciated rate-base methodology "double counts a large portion of plant costs for the purpose of deriving a 'reasonable' return on equity and then re-counts half the net depreciated cost of assets in the calculation of a deemed interest expense."[31] The NEB distinguished Cochin Pipelines' use of a semi-depreciated methodology on the basis that that situation was intended to provide for lower initial tolls and revenue for a newly constructed pipeline. The NEB ruled that Murphy should use a fully depreciated, original cost-base methodology.[32] On that basis, Murphy's net rate base for 2000 and 2001 would be $8,193,512 and $7,884,391, respectively.

The NEB went on to deem a 50/50 debt/equity ratio for the pipeline. It also held that a cost of debt of 7.25 percent and return on common equity of 13 percent would be reasonable, as the Milk River Pipeline is exposed to higher risk than Group 1 pipelines.[33]

With respect to toll structure, it was noted that for the past ten years Murphy charged a premium of 53.6 percent on light crude oil from the Manyberries Pipeline versus medium and heavy crude received from the Bow River Pipeline. The NEB held that it was

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30 *Supra* note 28 at 4-5.

31 *Ibid.* at 10.

32 See also *In the Matter of Plateau Pipeline Ltd. Taylor to Kamloops Pipeline Application for Permanent Tolls Decision* (26 June 2001) at 33-36 (BCUD) in which the B.C. Utilities Commission disallowed Plateau Pipeline's use of a semi-depreciated rate base in favour of a fully depreciated historical rate base methodology.

33 *Supra* note 28 at 12-13.

> aware of no other pipeline that charges a premium for the transportation of light versus medium or heavy crude oils. Rather, medium and heavy crude oils are generally charged premiums over light crude oil as is the case on both the Express and Enbridge systems. Murphy has not demonstrated that there is any significant difference in required facilities, services or costs, to justify any toll differential being applied to light crude oil. This unusual toll structure could be interpreted as further evidence of market power. Therefore, the Board is not satisfied that any premium for the transportation of light crude oil is warranted and has decided that tolls for light crude oil should be set at the same level as those for medium and heavy crude oils.[34]

In the result, the NEB determined the final tolls and directed Murphy to refund approximately $1.2 million plus 7.25 percent interest to shippers for the period from 1 September 2000 to the date of the NEB's decision (1 August 2001).

6. OH-1-2000: *ENBRIDGE PIPELINES INC. TERRACE EXPANSION PROGRAM PHASE 2*[35]

The NEB's decision in OH-1-2000 addresses, among other things, a request to condition an approval to ensure that commitments to First Nations are met, and the distinction between applications appropriately made under s. 52 versus s. 58 of the *NEBA*.

Enbridge Pipelines Inc. (Enbridge) applied to construct facilities comprising the Terrace Expansion Program Phase 2.[36] Those facilities consisted of approximately 126 kilometres of pipeline in three loops between Hardisty, Alberta and Kerrobert, Saskatchewan, as well as modifications and additions to existing pump stations. The pipeline loops were applied for under s. 52 of the *NEBA* (Certificate of Public Convenience and Necessity). The pump units, related facilities and station piping were applied for under s. 58 (exemption order).

With respect to Enbridge's commitments to First Nations, the Treaty Four–Treaty Six Federation of Saskatchewan Indian Nations Task Force (the Task Force) requested that the NEB impose conditions that would provide "assurances that Enbridge honour any current and future commitments it may have with the Task Force, that the company report to the Board regarding its activities related to these commitments and that Enbridge develop an Aboriginal Policy."[37]

The NEB acknowledged that in previous matters it had exercised its discretion to impose conditions similar to those proposed by the Task Force. It found, however, that there are preconditions to the exercise of this discretion:

> [The NEB] must have regard for the clarity, certainty and direct relation of the proposed condition to the applied-for project. The imposition of conditions which fail to meet any of the above criteria could jeopardize a project that has been approved in the public interest, by initiating prolonged debate or litigation over the interpretation of a condition.[38]

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34 *Ibid.* at 16.

35 *Enbridge Pipelines Inc. Terrace Expansion Program Phase II* (May 2001), OH-1-2000 (NEB) [*Enbridge Pipelines*].

36 Terrace Expansion Program Phase I was approved by the NEB in *Interprovincial Pipe Line Inc. (IPL) Oil Pipeline* (June 1998), OH-1-98.

37 *Supra* note 35 at 13.

38 *Ibid.* at 14.

In the present case, there had been considerable consultation between Enbridge and two First Nations groups, which resulted in a "letter of commitments." The NEB found that the commitments in that letter dealing with construction and operation were clear and unambiguous. The NEB expressed concern over imposing conditions which required another level of agreement between the parties prior to construction and operation. If such conditions were proposed and the parties were unable to come to further agreement, the matter might have to be referred back to the NEB for adjudication, thus resulting in uncertainty for Enbridge respecting approval of its project. The NEB ultimately imposed a single condition obligating Enbridge to keep the NEB apprised of various aspects of the project which relate to Aboriginal interests.[39]

The NEB also addressed the issue of when applications are appropriately made under s. 52, as opposed to applications made under s. 58. Section 52 is the general approval provision for pipeline facilities under the NEB's jurisdiction. It has more onerous filing requirements and is subject to Governor in Council approval.[40] Pursuant to s. 58, the NEB may authorize the construction and operation of short pipelines and surface facilities.[41] Such authorization does not require Governor in Council approval.

Enbridge indicated that the project was required to be in-service by the fourth quarter of 2001 and, in order to meet that date, construction of the station facilities had to commence no later than 15 May 2001. Enbridge argued that the time between receiving a s. 58 exemption order and a s. 52 certificate would be approximately one month. If an exemption for the station facilities was not granted, the entire project would not be completed in time.[42]

The NEB noted that it often issued s. 58 exemption orders for discreet projects, involving additions and modifications to existing pipeline facilities, and for new pipeline facilities no greater than forty kilometres in length. Section 58 exemptions had also been issued for portions of larger projects considered within a public hearing process after a careful

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39 *Ibid.* at 14-15.

40 *Supra* note 5, s. 52:

> The Board may, subject to the approval of the Governor in Council, issue a certificate in respect of a pipeline if the Board is satisfied that the pipeline is and will be required by the present and future public convenience and necessity and, in considering an application for a certificate the Board shall have regard to all considerations that appear to be relevant, and may have regard to the following:
> (a) the availability of oil, gas or any other commodity to the pipeline;
> (b) the existence of market, actual or potential;
> (c) the economic feasibility of the pipeline;
> (d) the financing responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity of participating in the financing, engineering and construction of the pipeline; and
> (e) any public interest that in the Board's opinion may be affected by the granting or the refusing of the application.

41 *Ibid.*, s. 58:

> (1) The Board may make orders exempting:
> (a) Pipelines or branches of or extensions to pipelines, not exceeding in any case 40 km in length, and
> (b) Such tanks, reservoirs, storage facilities, racks, compressors, loading facilities, inter-station systems of communications by telephone, telegraph or radio, and real and personal property and works connected therewith, as the board considers proper, from any and all of the provisions of sections 29 to 33 and 47.

42 *Enbridge Pipelines*, *supra* note 35 at 22.

consideration of the evidence. Exemption applications require clear and compelling evidence demonstrating that the relief sought is warranted.

The NEB referred to its Reasons for Decision in GH-4-98,[43] which addressed the issue of severing components of a project for the purpose of obtaining a s. 58 exemption. In that case, M&NP applied under s. 58 in respect of a five kilometres section of pipe, and the NEB held that:

> The Federal Court, in *Alberta and WestCoast Energy Inc.*,[44] the Pesh Creek Reference that we referred to earlier, said, and I quote: "*The Board is obviously not entitled to partition a project into multiple sections so as to be able to consider all or some of them under the exceptional provisions of section 58 of its enabling statute* —" That is a compelling argument for not granting the application as made. The Point Tupper Lateral is a single project. To allow the applicant to carve out 5 km of that project and to seek approval for that portion of the project under section 58 of the *NEB Act* would be contrary to the clear meaning of section 52 of the Federal Court's pronouncement in the *Pesh Creek* Decision. The 5 km that were applied for under section 58 will not be excluded from the facilities applied for under section 52 of the Act.[45]

Enbridge attempted to distinguish GH-4-98 from the present case on the basis that M&NP sought an exemption for an indiscreet section in the middle of a contiguous pipeline, whereas Enbridge's application was for discreet pump and associated facilities located wholly on Enbridge land.

The NEB did not accept that the station facilities were discreet from the pipeline, as Enbridge had acknowledged that the station facilities could not be used without the loops.[46] Further, in this case the delay in obtaining Governor in Council approval was expected to be only one month. The NEB held that it was not in the public interest to grant an exemption order in the absence of some clear evidence of serious detriment to the project.[47]

In the result, the NEB approved the entire Terrace Expansion Program Phase 2 pursuant to s. 52 of the *NEBA* and exempted Enbridge from certain filing requirements.

B. ALBERTA ENERGY AND UTILITIES BOARD

1. DECISION 2002-044: *NGTL GENERAL TERMS AND CONDITIONS: INTERPRETATION OF ARTICLE 3 AS IT RELATES TO CO_2*[48]

The AEUB's recent Decision 2002-044 clarifies the legal interpretation of the gas quality specification provisions set out in Nova Gas Transmission Limited's (NGTL) tariff. A further proceeding is contemplated to examine the appropriateness of those specifications as they relate to CO_2.

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43 *Maritimes and Northeast Pipeline Management Ltd., Point Tupper Lateral Facilities Application, as amended, dated 14 August 1998* (January 1999), GH-4-98 (NEB).
44 *Alberta v. WestCoast Energy Inc.* [1997] F.C.J. No. 77 (QL).
45 *Supra* note 43 at 43 [emphasis in original].
46 *Supra* note 35 at 24.
47 *Ibid.* at 23.
48 (7 May 2002), AEUB Decision 2002-044 (AEUB).

On 21 December 2001 and 25 January 2002, a number of petrochemical and related entities (the Co-Applicants)[49] requested that the AEUB require NGTL to comply with and enforce its CO_2 specification at all receipt points until such time that the AEUB determines the appropriateness of another regime.

Article 3.1(e) of the NGTL tariff sets out the CO_2 specification as follows:

> 3.1 Quality Requirements
>
> Gas received at a Receipt Point: ...
>
> (e) *shall not* contain more than two (2%) percent by volume of carbon dioxide. [emphasis added]

The following other provisions of the NGTL tariff are also relevant to this decision:

> 3.2 Nonconforming Gas
>
> (a) If gas received by [NGTL] fails at any time to conform with any of the quality requirements set forth in paragraph 3.1 above, then [NGTL] *shall* notify Customer of such failure and [NGTL] *may*, at [NGTL's] option, refuse to accept such gas pending the remedying of such failure to conform to quality requirements. If the failure to conform is not promptly remedied, [NGTL] *may* accept such gas and *may* take such steps as [NGTL] determines are necessary to ensure that such gas conforms with the quality requirements and Customer *shall* reimburse [NGTL] for any reasonable costs and expenses incurred by [NGTL].
>
> (b) Notwithstanding subparagraph 3.2(a), if gas received by [NGTL] fails to conform to the quality requirements set forth in paragraph 3.1 above, [NGTL] *may at its option* immediately suspend the receipt of gas, provided however that any such suspension shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to [NGTL].
>
> 3.3 Quality Standard of Gas Delivered at Delivery Points
>
> Gas which company delivers at Delivery Points *shall* have the quality that results from gas having been transported and commingled in the Facilities.[50]

On 16 and 17 April 2002, the AEUB heard argument on the proper interpretation of Article 3. The debate centred around the extent of NGTL's discretion, if any, to accept gas containing more than two percent CO_2 by volume. Not surprisingly, the AEUB confirmed that the words "shall" and "may," as they are used in Article 3, are to be given their plain and ordinary meaning;[51] that is, "shall" is imperative and "may" is permissive. In making that finding, the AEUB noted that NGTL's tariff is a hybrid between a contract (between NGTL and its customers) and a regulation to the extent that its provisions are approved by the

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49 NOVA Chemicals Corporation, the Industrial Gas Consumers Association of Alberta, Dow Chemicals Canada Inc. and Williams Energy Services.

50 *Supra* note 48 at 7-8, 9 [emphasis in original].

51 *Ibid.* at 6, 8.

AEUB, and thus are not entirely at the discretion of the parties to the "contract." Consequently, principles of both contractual and statutory interpretation applied.[52]

The AEUB did not accept the Co-Applicants' argument that NGTL's discretion to accept "out of spec" gas was for a limited time period, such as under upset conditions. Instead, the AEUB found that Article 3 was to interpreted as follows:

> Paragraph 3.1(e) is a receipt point specification, and does not relate to delivery points.
>
> Under paragraph 3.2, NGTL has the discretion to accept or not accept gas containing more than 2% CO_2, by volume, and there is no express limit in paragraph 3.2 regarding how long NGTL may accept gas containing more than 2% CO_2 by volume.
>
> Paragraph 3.3 indicates that gas delivered at the delivery points has the quality resulting from commingling.[53]

However, the AEUB also noted that "the discretion of NGTL, set out in paragraph 3.2, can only be reconciled with the quality requirement of paragraph 3.1(e) if NGTL does exercise its discretion in a reasonable and principled manner, and in accordance with set criteria."[54] That finding is consistent with NGTL's duty under s. 25 of the *Gas Utilities Act*[55] to ensure that its actions and tariff do not have the effect of unjust discrimination or an unjust preference.

Having established the proper legal interpretation of gas quality specifications contained in Article 3, the AEUB will now convene a proceeding to consider the appropriateness of those specifications as they relate to CO_2 and, presumably, the Co-Applicants' interests in the CO_2 content of commingled gas at NTGL delivery points.

2. DECISION 2002-032: *CASE RESOURCES INC., ENHANCED OIL RECOVERY SCHEME, OIL WELL EFFLUENT AND WATER PIPELINES, CARROT CREEK FIELD*[56]

This decision illustrates, among other things, the respective roles and jurisdiction of the AEUB and Alberta Environment (AENV) regarding waterflood schemes.

The Carrot Creek Cardium GG Pool (GG Pool) began producing in 1983. By 1995, thirteen of the producing wells had been either shut-in or abandoned due to low oil flow rates. Cumulative production during that time totalled 54.2 10^3m^3 of oil and 44.1 10^6m^3 of gas. In 1996, the AEUB issued Approval No. 7947, pursuant to the *Oil and Gas Conservation Act*,[57] authorizing an enhanced oil recovery scheme (water injection) proposed by Murwell Resources (Murwell). Murwell also obtained Licence No. 19960429 from Alberta Environment pursuant to the *Water Act*,[58] authorizing the annual use of a maximum

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52 *Ibid.* at 5-6.
53 *Ibid.* at 9.
54 *Ibid.* at 10.
55 R.S.A. 2000, c. G-5.
56 (26 March 2002), AEUB Decision 2002-32 (AEUB).
57 R.S.A. 1980, c. O-5 [*OGCA*] [now cited as R.S.A. 2000, c. O-6].
58 R.S.A. 1980, c. W-3.5, s. 49 [now cited as R.S.A. 2000, c. W-3, s. 49].

of 19.3 million imperial gallons (87.7 10^3m^3) at a maximum rate of 40 imperial gallons (0.182 m^3) per minute. Murwell commenced the waterflood in the spring of 1996. From that time to November 2001, an additional 14 10^3m^3 of oil and 500 10^3m^3 of gas was produced from the GG Pool.

In 2001, Case Resources (Case), as successor in interest to Murwell and as the current operator of the waterflood, applied to amend AEUB Approval No. 7947 to add a new injection well (the 16-15 Well) in the northern part of the GG Pool. Case also applied for authorization to construct and operate a produced and fresh water pipeline from Case's water source well to the 16-15 Well and various extensions to the existing gathering system to connect suspended wells in the northern part of the GG Pool. Case estimated that as much as an incremental 1,118.7 10^3 bbl (177.8 10^3m^3) of oil could be recovered with the proposed additional water injection. Further, an estimated 320 10^3m^3 bbl (50.8 10^3m^3) of water injected over eight to ten months would be required to repressure the northern portion of the GG Pool. Produced water would also be reinjected, thus reducing further fresh water requirements to approximately the volume of oil produced.

Case's application was opposed by local landowners (the Webbs) who raised concerns about, among other things, the impact on the quality and level of domestic and livestock water supplies, the route selection of pipelines and constraints that pipelines would put on land use. AENV appeared as a Friend of the AEUB to explain the department's policy respecting groundwater allocation for oilfield injection and to answer questions about Case's *Water Act* licence.

In approving the 16-15 Well as an injection well, the AEUB noted its conservation mandate under s. 4(a) of the *OGCA* and confirmed its requirement that operators fully investigate enhanced recovery feasibility for new pools and timely implementation where technical, economic and impact issues warrant. The AEUB went on to find that the GG Pool is technically suited to waterflood optimization, but expressed "some disappointment" with the scheme's untimely commencement. The AEUB noted that a more timely implementation of the waterflood would have resulted in more incremental production and significantly less injected water to repressure the pool.[59]

The AEUB clarified AENV's role in approving waterflood schemes as follows:

> the Board notes that the jurisdiction and management of our provincial water resources are with AENV. To address its broad public interest mandate respecting the province's energy resources, the EUB must take into account the province's public policy on multi-use of water resources and how site-specific water licences are managed.... The Board notes that AENV will have an opportunity to review Case's licence [under the *Water Act*] when it applies for renewal prior to December 31, 2003.[60]

Appropriate use of water from Case's water source well is regulated by the terms of its *Water Act* Licence No. 19960429. Murwell would have been required to investigate the use of

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59 *Supra* note 56 at 8.
60 *Ibid.*

surface water, non-potable ground water and non-water alternatives prior to applying for that licence.

With respect to the Webbs' expressed concerns about the impact on the quality and level of domestic and livestock water supplies, the AEUB accepted the evidence of Case and AENV that there appeared to be a low probability of any communication between the aquifer in the Case water source well and the Webbs' domestic water well. Further, the aquifer that Case was using was not part of the hydraulic flow regime providing water to the springs located on the Webbs' property. Therefore, it was unlikely that withdrawals from the Case water source well had or would have any adverse impact on surface water on the Webbs' land.[61]

The AEUB appeared to take comfort from the fact that Case would have to renew its Licence No. 19960429 before 31 December 2003, thus providing an interested party, such as the Webbs, the opportunity to challenge the renewal if they could demonstrate that renewal of the licence would have an adverse effect on them. The AEUB also noted Case's commitment to conduct semi-annual monitoring and testing of the Webbs' domestic and livestock water wells and suggested that such monitoring and testing obligations be incorporated into the *Water Act* licence renewal.

The AEUB went on to deny Case's application for the water pipeline and gathering system extensions. The Webbs had expressed concerns regarding the proposed pipeline routing. Case submitted that it had examined alternative routes and ruled them out on the basis of impracticability and cost. It appears, however, that Case did not adduce evidence of detailed route comparisons. The AEUB found that it was "hindered by the lack of detailed route comparison, survey information, and offset landowner views."[62] Further, "Case has not fully investigated alternative routes that may result in a better project, considering all issues. In the absence of such detailed information, the Board finds it cannot reach a proper decision on the optimum route."[63]

In the result, the AEUB authorized Case to use the 16-15 Well as a new injector, but denied, without prejudice to a future application, Case's applications for a pipeline to transport water to that well and pipelines to gather the resulting incremental production.

3. DECISION 2002-020: *COMSTATE RESOURCES LTD., APPLICATION FOR SWEET NATURAL GAS PIPELINE, PEMBINA FIELD*[64]

The AEUB's expectations respecting industry's obligation to conduct a thorough and informative public consultation program are well established (see Part II.B.5 below). Often third-party consultants, such as land agents, undertake these public consultation activities. The following AEUB decision provides a caution to project proponents when retaining and instructing such consultants.

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61 *Ibid.* at 7, 9.

62 *Ibid.* at 12.

63 *Ibid.* at 13-14.

64 *Examiner's Report Respecting Comstate Resources Ltd. Application For Sweet Natural Gas Pipeline Pembina Field* (19 February 2002), AEUB Decision 2002-20 (AEUB).

Comstate Resources (Comstate) applied to construct and operate a sweet gas gathering system. Two local landowners expressed concerns about the right-of-way acquisition process, the pipeline route, land reclamation and the effect of construction, operation and abandonment of the pipeline on current and future land uses. Maltais, one of the landowners, retained a land consultant who assisted him in developing a list of twenty-seven conditions proposed to be incorporated into the right-of-way agreement.

The AEUB examiners considered the need for the pipeline, location of the pipeline, impacts caused by construction and reclamation, operation and abandonment and found in favour of Comstate on those issues.[65] They also considered the issue of "communication and the use of the 27 conditions." Comstate submitted that it had been successful in signing right-of-way agreements with seven of nine landowners impacted by the project. Further, it conducted a majority of its right-of-way negotiations through contract landmen or third-party consultants. Comstate was usually successful in conducting negotiations in this manner. When problems arose, senior company personnel were prepared to become involved.

Initial negotiations between Comstate's contract landman and Maltais began in July 2000. These negotiations progressed to a point in July 2000 when Comstate's landman apparently agreed in principle to a revised version of the twenty-seven conditions proposed by Maltais.[66] Comstate's evidence was that it was not initially aware of such agreement. Maltais alleged that Comstate subsequently withdrew from the agreement in principle unilaterally, thus damaging the trust between the parties and confusing the matter, as he did not know whether the landman had the authority to make such agreements.

The AEUB examiners found that:

> The examiners appreciate how promptly Comstate senior staff responded when they became aware of Mr. Maltais's concerns. However, this was after lengthy negotiations and after Comstate had overruled some of the previous agreements negotiated by the landman. The examiners recognize Comstate's need to use consultants and that this practice is successful in most instances. However, the examiners have *significant concern with Comstate's practice to delegate matters to third-party consultants without establishing firm guidelines about when to involve company staff and without clearly setting out the degree of authority that can be exercised by the consultants.* In this instance, the good-faith negotiations that occurred between Mr. Maltais and the contract landman on behalf of Comstate were followed by a deteriorating of trust between the two parties. The examiners are concerned that this became a lost opportunity and appears to have resulted in lowered trust between the parties when it became clear that the individual at the table for Comstate did not have the authority to respond adequately to this level of negotiations.[67]

The AEUB examiners also addressed Maltais' concern regarding his difficulty in obtaining information and long intervals between contacts with Comstate. They found that the issue of prompt and sufficient information is a responsibility that is shared by all parties and "should either party have concerns regarding long delays, the onus was on them to contact the other party regarding the lack of information or a response."[68]

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65 The examiners' findings and recommendation were subsequently adopted by the AEUB.

66 *Supra* note 64.

67 *Ibid.* at 13-14 [emphasis added].

68 *Ibid.* at 14.

In the result, the AEUB examiners found that certain of the twenty-seven conditions were not appropriate or were already covered by regulations. Accordingly, they did not recommend that any of the conditions be linked to the AEUB approval.

4. DECISION 2002-16: *NOVA GAS TRANSMISSION LTD., APPLICATION FOR APPROVAL OF COSTS, DELIVERY SERVICE TO THE FORT MCMURRAY AREA*[69]

The competitive market for intra-Alberta gas transportation services continues to evolve with a recent development involving NOVA Gas Transmission Ltd.'s (NGTL) entry into the Fort McMurray area. As noted in Part II.B.9 below, approval of costs relating to NGTL providing delivery service into the Fort McMurray area was not addressed in NTGL's 2001-2002 settlement or Decision 2001-44,[70] which approved that settlement. Rather, parties to the settlement elected to defer the matter to future negotiation or to an NGTL application.

Subsequent to Decision 2001-44, NGTL applied to the AEUB for approval to include in its revenue requirement transportation-by-others (TBO) costs related to service requests by Petro-Canada Oil and Gas (Petro-Canada), Suncor Energy and Syncrude Canada. At that time, gas delivery into the Fort McMurray area was served by four existing pipelines: the Albersun pipeline serving Suncor, a Simmons Group pipeline serving Syncrude and others, a NOVA Pipeline Ventures (Ventures) pipeline serving Suncor and Williams Energy (Canada) (Williams) and ATCO Pipeline's (ATCO) Muskeg River Pipeline serving the Albian Sands Energy oilsands facility, which is a joint venture among Shell Canada, Chevron Canada and Western Oil Sands. The Petro-Canada and Suncor service requests were for incremental volumes into the area. It appears that approximately half of Syncrude's original 89 MMcf/d service request was currently subject to a short term contract with Ventures that could be terminated if NGTL's application was approved.[71]

To provide the requested service, NGTL evaluated several options: (i) constructing new facilities; (ii) providing TBO arrangements on an existing pipeline; and (iii) purchasing an existing pipeline. NGTL conducted a bid process to determine the lowest cost of the three alternatives. TBO bids were received from Albersun, Simmons and Ventures. Based on those bids and its evaluation of the construction and purchase options, NGTL determined that a TBO arrangement with Ventures until 2004 and new construction thereafter was the lowest cost option on a cumulative present value cost of service basis over a thirty-year period. It would also allow NGTL to avoid significant investment until longer-term requirements were better defined. The NGTL/Venture's TBO arrangement provided for a monthly firm service demand charge of $3.65/Mcf for the period up to 31 October 2004, with renewal rights on twelve months' notice. While incremental volumes could be offered on the same terms if capacity was available, NGTL would not solicit bids for incremental volumes.

In approving NGTL's application, the AEUB considered the following issues: (i) whether a generic hearing was required to determine the rules of competition for intra-Alberta gas transportation; (ii) the regulatory and commercial framework; (iii) the impact of approving

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69 (5 February 2002), AEUB Decision 2002-16 (AEUB) [*Nova Gas Costs*].

70 *Infra* note 112.

71 *Supra* note 69 at 5-6, 21.

NGTL's application on others (the existing pipelines, their shippers and NGTL's ratepayers); (iv) the appropriateness of the proposed affiliate transaction; and (v) cost accountability respecting intra-Alberta delivery service.

The AEUB denied requests by ATCO and Alberta Laterals Company (ALC) for a generic hearing. In doing so, the AEUB held that such a process would necessarily involve other pipelines in Alberta and could be time consuming. It would be unreasonable to cause new facilities or services to wait until a generic proceeding is completed. The AEUB also noted that many issues raised by ATCO and ALC are matters subject to continuing negotiation among NGTL and its stakeholders. Accordingly, the AEUB directed NGTL to file a progress report on those negotiations no later that 1 August 2002, and to file a negotiated settlement or application no later than 31 December 2002.[72]

With respect to the regulatory and commercial framework, reference must first be made to Decision 2000-6, which approved NGTL's 1999 Products and Pricing application.[73] In that decision, the AEUB determined that the cost of new laterals would no longer be rolled into NGTL's rate base or revenue requirement. ATCO and Shell took the position that the regulatory and commercial framework was established when NGTL chose to pursue service to Fort McMurray through its unregulated affiliate (Ventures) as approved by the AEUB, rather than extending the NGTL mainline. As such, they argued that NGTL should not now be allowed to extend its mainline service into that area. The AEUB held that its approval of the Ventures pipeline and any of the other existing pipelines did not predetermine the regulatory and commercial framework so as to preclude NGTL or any other regulated or unregulated pipeline from serving Fort McMurray.[74]

Having determined that NGTL was not precluded from extending its mainline service into the Fort McMurray area, the AEUB next assessed the potential impact that the service applied for would have on the existing pipelines, their shippers and NGTL's ratepayers. That issue involved the fact that shippers on any of the four existing pipelines had to pay an NGTL receipt charge for gas sourced on the NGTL system, an intra-Alberta delivery charge which was set at zero in accordance with NGTL's rate design approved in Decision 2000-6,[75] and a toll to the respective existing pipeline. Under NGTL's application, however, shippers accessing the NGTL/Ventures TBO arrangement would only pay the NGTL receipt change and the intra-Alberta delivery charge, set at zero. NGTL determined that the TBO arrangement should be viewed as a mainline extension consistent with Decision 2000-6 and NGTL's Facility Liaison Committee's Guidelines for New Facilities.[76] As such, the TBO costs would be rolled into NGTL's rates.

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72 *Ibid.* at 9.

73 *NOVA Gas Transmission Ltd. 1999 Products and Pricing* (February 2000), AEUB Decision 2000-6 (AEUB) [*Nova Gas Pricing*].

74 *Supra* note 69 at 11.

75 *Supra* note 73 at 1, 20, 50-51.

76 *Ibid.* at 62: "[T]he Board accepts as reasonable NGTL's submission that in general new connections of 12 inches or less in diameter distinctly associated with one or a few customers would normally be considered laterals, while facilities required to meet the aggregate forecast of more than one customer would normally be classified as mainlines."

Shell Canada Ltd. (Shell) took the position that it would be at an unfair competitive disadvantage relative to other oil sands producers able to access NGTL's TBO proposal. Shell's volumes were subject to a long-term agreement with ATCO supporting the Muskeg River Pipeline. The terms of that agreement, however, were not made public. Similarly Williams, as the anchor shipper on the Ventures Pipeline, noted that it would receive similar service to shippers under the TBO arrangement, but would still have to pay a separate toll to Ventures. ATCO and ALC took the position that approval of NGTL's application put them at a competitive disadvantage — ATCO because its Muskeg River Pipeline would be unable to attract incremental volumes and ALC because it would have to charge incremental rates, whereas NGTL could roll-in costs for mainline extensions. NGTL suggested that, while the toll impact on its system would depend upon the volumes retained at its receipt points, incremental delivery volumes could have the effect of attracting incremental receipt volumes, thus leading to a toll reduction.

The AEUB noted that, due to limited evidence or, in some circumstances, no evidence, it could not assess whether approval of NGTL's application would have a material impact on Shell or Williams. Nonetheless, the AEUB found that:

> both of these shippers, and others on existing facilities, might be disadvantaged due to the proposed service extension. The Board further believes that as long as the costs of intra-Alberta delivery service continue to be recovered by current methodology, there is no price transparency. This transfer of income from system-wide shippers to a selected few could inhibit competition and result in inefficient intra-Alberta delivery services, to the detriment of NGTL, its shippers, and ultimately intra-Alberta customers.[77]

Further, respecting NGTL's claim that its application may lead to a toll reduction, the AEUB noted that that would only be the case if the incremental volumes attracted would not have accessed the NGTL system absent the TBO arrangement. No evidence was adduced on that point.

With respect to the appropriateness of the proposed TBO transaction between NGTL and its affiliate Ventures, the AEUB restated its view that not only must affiliate transactions be conducted at arm's length, they must also be perceived to be conducted at arm's length. Some intervenors did not perceive that standard to have been met. The AEUB went on, however, to note that even though NGTL had yet to implement an AEUB-approved code of conduct, there was no evidence that the NGTL/Ventures TBO arrangement was inappropriate as a result of the parties' affiliate relationship. In the present case, the Ventures Pipeline was the only existing pipeline that had available capacity and ATCO did not submit a TBO bid to NGTL. Further, no one had suggested that Ventures' demand charge was excessive.[78]

The final issue addressed by the AEUB was cost accountability respecting intra-Alberta delivery service. That issue, like the question of impact on other parties, involved the fact that the TBO arrangement was proposed as a mainline extension and that intra-Alberta delivery service would be charged a zero rate. The AEUB addressed the issue in two steps: first, whether the proposed delivery service extension satisfied the criteria set out in Decision

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77 *Supra* note 69 at 14.

78 *Ibid.* at 16.

2000-6; and second, whether intra-Alberta customers should be denied mainline delivery service on NGTL solely on the basis of the current rate structure as approved in Decision 2000-6.

The AEUB answered the first question in the affirmative, finding that "the requested service is to satisfy the aggregate demand of more than one customer in an area with a significant potential for increased natural gas requirements."[79] Regarding the second question, the AEUB held that:

> it would not be fair, just or reasonable to deny intra-Alberta customers new mainline delivery service consistent with current rate structure for intra-Alberta service. Nor would it be fair to deny this service based on unresolved cost accountability issues, particularly as the Board believes that these issues are not necessarily confined to mainline delivery extensions into the intra-Alberta market, but apply to NGTL's system expansion in general.[80]

In the result, the AEUB held that:

> [the] *desire to satisfy the need for service by rapidly growing industrial activity in the province has to be balanced with the desire to foster competition, by providing the right market signal and transparency in pricing of the service provided.* The Board is therefore prepared to approve the proposed TBO arrangements, but is only prepared to approve the inclusion of their costs over the term of the Settlement. The Board expects that either an agreement will be submitted regarding proper cost allocation among receipts, intra-Alberta and ex-Alberta deliveries, or an application will be filed with the Board for its consideration on or prior to expiration of the Settlement on December 31, 2002.[81]

5. DECISION 2001-109: *STAMPEDE OILS INC., SECTION 42 REVIEW OF WELL LICENSE NO. 0239741 AND APPLICATIONS FOR ASSOCIATED PIPELINES, TURNER VALLEY FIELD*[82]

Decision 2001-109 confirms the procedure and test applied by the AEUB in considering a review and variance application. It also illustrates the importance of clearly communicating and fulfilling commitments made to stakeholders during public consultation.

On 14 July 2000, the AEUB issued Stampede Oils (Stampede) a well licence in respect of a sour well (the 2-34 Well). The licence was issued having regard to the withdrawal of certain landowner objections based on commitments made by Stampede. Stampede finished drilling the 2-34 Well on 10 November 2000, and was in the process of completing its well when the matter came before the AEUB. On 12 December 2000, a group of local residents (the Intervenor Group) applied under s. 42 of the *Energy Resources Conservation Act*[83] for a review of the AEUB's decision to issue the 2-34 Well licence.[84]

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79 *Ibid.* at 19.
80 *Ibid.* at 20.
81 *Ibid.* at 21 [emphasis added].
82 (20 December 2001), AEUB Decision 2001-109 (AEUB) [*Stampede Oils*].
83 R.S.A. 1980, c. E-11 [*ERCA*] (now R.S.A. 2000, c. E-10, s. 39).
84 Stampede also applied on 21 August 2001, for a pipeline permit to construct and operate a sour oil effluent gathering line to tie in the 2-34 Well. That application was considered at the same proceeding.

The first matter considered by the AEUB was whether to grant the review application. Section 42 provides that the AEUB may review, rescind, change, alter or vary an order or direction made by it. The AEUB confirmed its procedure to consider such applications in two stages: "The first step is to determine the preliminary question as to whether the review should be granted, and the second step, if it is granted, is to hold a hearing on the merits."[85] The AEUB then referred to the tests now set out in s. 46(5) of its new *Rules of Practice*[86] (see Part III.B.4 below).

In the present case, the Intervener Group alleged new facts and changed circumstances. Specifically, it claimed that Stampede had flared sour gas, that it had been unable to contact Stampede's representative listed in the emergency and information packages and that Stampede failed to notify it prior to commencing completion operations, all of which were contrary to Stampede's prior commitments. By way of letters dated 12 June and 13 July 2001, the AEUB determined that a hearing on the merits should be held since "the area landowners raised a reasonable possibility that a review of these circumstances might alter the original decision to grant the well licence."[87]

After deciding that the review request should be granted, the AEUB went on to hold a hearing on the merits. The AEUB considered the following issues: (i) commitments; (ii) compliance; (iii) mineral rights, reserves, and productive capability; (iv) need for the pipeline and related matters; (v) public consultation, communications, and community relations; (vi) operations management; and (vii) future operations.

During its public consultation program, Stampede made an extensive number of commitments to the Intervener Group, and reduced them to writing in information packages that were provided to the Intervener Group. Among other things, Stampede committed: (i) to notifying residents before commencing completion or testing operations; (ii) to not flaring gas during well testing or production operations at the well site; (iii) to providing for veterinary and transportation services for livestock; and (iv) to working towards use of a sumpless drilling system to mitigate environmental effects. The Intervener Group took the position that Stampede did not fulfill its commitment to provide it with notice prior to a flaring incident. Further, Stampede did not explain that there might be some flaring during completion operations, nor did it make appropriate livestock transportation arrangements.

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85 *Supra* note 82 at 5.

86 Alta. Reg. 101/2001at s. 46(5):

> After determining the preliminary question under subsection (4), the Board may
> (a) dismiss the application for review if,
> (i) in the case where the applicant has alleged an error of law or jurisdiction or an error in fact, the Board is of the opinion that the applicant has not raised *a substantial doubt as to the correctness* of the Board's order, decision or direction, or
> (ii) in the case where the applicant has alleged new facts, a change of circumstances or facts not previously placed in evidence, the Board is of the opinion that the applicant has not raised *a reasonable possibility that the new facts, the change in circumstances or the facts not previously placed in evidence, as the case may be, could lead the Board to materially vary or rescind* the Board's order, decision or direction, or
> (b) grant the application. [emphasis added]

87 *Supra* note 82 at 6.

The AEUB noted Stampede's acknowledgement that it failed to notify residents before commencing completion or testing operations due to an oversight related to changing its engineering consultant. Further, because Stampede's discussion with residents about flaring did not specifically identify conditions when flaring might occur, it was reasonable that the Intervener Group might expect no flaring at Stampede's well site during any of its operations. The Intervener Group also appeared to have different expectations regarding the livestock transportation arrangements. The AEUB concluded with the following passage:

> The Board believes that Stampede failed to meet resident expectations with respect to its commitments related to sumpless drilling, flaring, and notification of completion operations. That said, the Board does not believe that the incidents in question compromised public safety. *Of greater concern to the Board is the apparent lack of management control and/or the miscommunication within Stampede's project team of staff and consultants. First, commitments were apparently made without a process to test practical feasibility. Second, the commitments were not communicated in a fashion that ensured consistency between resident understanding and Stampede's intentions. Third, Stampede failed to ensure that its obligations arising from its commitments* (e.g., notification of residents prior to starting well completion operations) *were properly communicated when staff and contractors changed.*[88]

In the result, the AEUB determined it was in the public interest to continue the 2-34 well licence under the condition that Stampede file the following: (i) a strategic and tactical plan outlining its public consultation/community relations program; (ii) terms of reference for an operations and compliance management plan within four months; and (iii) an operations and compliance management plan developed from the terms of reference, as well as an independent third-party audit of its management system and the regulatory compliance of its facilities, all within one year.[89]

6. EXAMINER REPORT E2001-05: *ARTEMIS ENERGY LIMITED, COMPULSORY POOLING, THREE HILLS CREEK FIELD*[90]

In this decision, a panel of AEUB examiners considered whether the majority or minority working interest owner should be appointed as operator pursuant to an AEUB pooling order.

Artemis Energy (Artemis) acquired all of the gas rights for s. 35, except for those in the NW¼, which were held by Gauntlet Energy (Gauntlet). Gauntlet was also owner and operator of the closest gas plant (the Gauntlet Plant). In February 2001, Artemis drilled a well (the 8-35 Well) and encountered a productive Belly River reservoir. Through negotiations and the AEUB's Appropriate Dispute Resolution process, Artemis and Gauntlet were able to agree on all aspects of a voluntary pooling arrangement with the exception of operatorship. To resolve the impasse, Artemis applied to the AEUB for, among other things, a pooling order designating it as the operator. Gauntlet opposed the application.

Artemis took the position that it should be the operator because it had the majority interest within s. 35; it had licensed, drilled and completed the 8-35 Well and it was an experienced

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

89 *Ibid.* at 30.

90 (8 August 2001), AEUB Examiner Report E 2001-5 (AEUB).

operator recognized by the AEUB. Artemis also noted that Gauntlet would be in conflict of interest as both operator of the 8-35 Well and the Gauntlet Plant, which was located only one hundred metres away. Artemis alleged that if the 8-35 Well was tied into the Gauntlet Plant, processing capacity available for the 8-35 Well could be reduced, resulting in potential drainage from s. 35. In that case, if Artemis was the operator, it could immediately make other arrangements.

Gauntlet took the position that it should be the operator if the 8-35 Well was tied into its gas plant, since that would be most practical from an operational perspective. It could co-ordinate the handling of potential problems, scheduled maintenance and safety issues that may arise. Gauntlet suggested that given the proximity of the 8-35 Well and the reasonable processing fee offered to Artemis, the Gauntlet Plant was the most economic option. With respect to the allegation of conflict of interest, Gauntlet took the position that a standard operating agreement should address Artemis' concerns and Artemis could seek alternative arrangements or regulatory relief if required.

The AEUB examiners noted that, because Artemis and Gauntlet were not able to agree upon a pooling arrangement, there was a need for a pooling order. With respect to who should be appointed as operator, normal AEUB practice was to name the well licensee as operator. That practice was established because the AEUB holds the licensee accountable for well operations through to abandonment, even if the well licensee retains a contract operator to physically operate the well on a day-to-day basis. The AEUB's practice would be applied unless there were compelling reasons justifying otherwise.[91]

The AEUB examiners concluded that there were no substantive reasons why Artemis should not be appointed operator of the 8-35 Well, and held that:

> It is not unusual for a well licensee to operate its own well that is producing into another party's facility without unduly hampering day-to-day operations or safety. There is no reason to consider that Artemis would not be cooperative when activities need to be coordinated. The examiners note that Artemis is not opposed to using the same contract operator for the 8-35 well as that engaged by Gauntlet to alleviate any concerns that Gauntlet may have with regard to coordination of the operations of the different facilities.[92]

Recognizing that Gauntlet's request to be named operator was conditional on the 8-35 Well being tied into the Gauntlet Plant, the AEUB examiners also held that a pooling order should not contain terms that limit the well licensee's ability to pursue what it considers to be the best means of placing the well on production and of obtaining an equitable share of pooled reserves. In the present case, the issue of where the 8-35 Well should be tied in was beyond the scope of the pooling application and it would be inappropriate for the decision to point directly to a specific facility or tie in.

The AEUB examiners went on to find that Artemis' conflict of interest issue was a valid concern and naming Gauntlet as operator could give it an undue advantage in a potential equity dispute. They stated that: "In the event that a conflict-of-interest issue arises, the

[91] *Ibid.* at 4.
[92] *Ibid.* at 4-5.

examiners believe that a scenario where Artemis is pursuing options while Gauntlet has the right to operate the 8-35 well may be prejudicial to Artemis."[93]

7. DECISION 2001-63: *PETRO-CANADA OIL AND GAS, INTERIM SHUT-IN OF GAS PRODUCTION, CHARD AREA*[94]

Perhaps the most significant regulatory development in Alberta in recent years has been the gas over bitumen proceedings. Of particular note is the AEUB's Decision 2000-22 respecting Gulf Canada Resources' application to shut-in gas production in the Surmont area.[95] In that decision the AEUB ordered the shut-in of 146 out of 186 wells to avoid pressure loss and hence production loss in bitumen formations. The AEUB is currently hearing applications by Petro-Canada Oil and Gas (Petro-Canada) and Franco-Nevada Mining Corporation (Franco-Nevada) to shut-in certain gas production in the Chard area and the Leismer Field.[96] Those hearings are expected to be completed shortly.

On 29 January 2001, Petro-Canada applied under the *Oil Sands Conservation Regulation*[97] for an order to shut-in Wabiskaw-McMurray gas production from a number of wells in the Chard area. Petro-Canada submitted that shut-in of gas production was necessary in order to prevent sterilization of the bitumen resource in the area since the gas cap and bitumen were in pressure communication. Franco-Nevada also made a similar application.

On 26 April 2001, the AEUB advised that it would hear the Petro-Canada and Franco-Nevada applications together. Further, the AEUB denied Petro-Canada's request for an interim shut-in order on the basis that "the evidence required to make such a determination is both detailed and complex and, therefore [the AEUB] was not prepared to make such a decision in advance of considering all the evidence at the main hearing."[98] Petro-Canada subsequently filed an application for review and variance of the AEUB's 26 April decision. After receiving submissions from the Chard Gas Producers[99] (the CGP) and Northstar Energy opposing Petro-Canada's review application, the AEUB decided on 5 June 2001, to hold a hearing on Petro-Canada's request for an interim shut-in order.

The first issue addressed by the AEUB was whether it had jurisdiction to shut-in gas wells on an interim basis. Section 3(5) of the regulation provides:

> [W]here it appears to the Board that the ultimate recovery of crude bitumen in the oil sands strata may be affected by gas production, the Board may, on its own initiative or on application by an affected party, make

93 *Ibid.* at 5.

94 (2 August 2001), AEUB Decision 2001-63 (AEUB) [*Petro-Canada*].

95 *Gulf Canada Resources Limited, Request for the Shut-In of Associated Gas, Surmont Area* (March 2000), AEUB Decision 2000-22 (AEUB) [*Gulf Surmont*]. See also *AEUB Inquiry: Gas/Bitumen Production in Oil Sands Areas* (March 1998).

96 AEUB Application Nos. 1085793 and 1086353.

97 Alta. Reg. 76/88, s. 3(5).

98 *Supra* note 94 at 1.

99 Calpine Canada Natural Gas Company, Canadian Forest Oil Ltd., Paramount Resources Ltd. and Rio Alto Exploration Ltd.

any order or directive it considers necessary to affect the conservation of the crude bitumen in any particular case.[100]

The AEUB went on to note that, while the tripartite test applied by the courts for injunctive relief (serious question to be tried, irreparable harm and balance of convenience) provides some guidance, its strict application was not appropriate for an interim shut-in application. The AEUB's primary concern in such circumstances is the conservation of energy resources, and that matter would be moot if ongoing pressure declines, leading up to the main hearing, resulted in reduced bitumen recovery. The AEUB held that irreparable harm need not be proved conclusively by Petro-Canada, nor was it necessary to consider the balance of convenience between the parties, stating that "[w]here it appears to the Board that bitumen recovery may be affected by gas production, the Board may take such conservation action that it deems necessary. The Board's focus is centred on the potential for significant waste of bitumen resources during the period required to consider the main shut-in application."[101] The AEUB also held that it did not have the authority to compel Petro-Canada to provide an undertaking for damages as would likely occur in a civil action where interim injunctive relief is granted.

After finding that it had the requisite jurisdiction to issue an interim shut-in order and determining the appropriate test to be applied in this case, the AEUB went on to consider, among other things, the geological interpretation, the effect of associated gas production on bitumen recovery by steam-assisted gravity drainage (SAGD), the feasibility of artificial repressuring, economics and public interest.

With respect to the geological interpretation, the AEUB identified geology which, based on the well logs before it, indicated no vertical communication between the gas cap and the bitumen layer where basal mudstones were present, but communication in the absence of such mudstones. Further, "the bitumen within the underlying stacked channel sands at Chard is of sufficient quantity and quality to warrant consideration for protection for future development."[102] Applying the definition of a "region of influence" from AEUB Interim Directive ID 99-1,[103] the AEUB identified ten wells in the Chard area that had the potential for communication between the gas and bitumen in underlying stacked channel sands.

The AEUB considered a number of reservoir simulation models to assess the effect of associated gas production on bitumen recovery, with regard to which Petro-Canada had been previously cross-examined during the Gulf Surmont proceeding. The AEUB held that:

Considering the previous extensive debate on Petro-Canada's simulation work and the differing views presented at the interim hearing, the Board believes there needs to be a more thorough debate of the simulation work for the Chard area before it is prepared to reconsider its conclusions on the simulation work submitted by Petro-Canada to the Gulf Surmont Hearing. Until this is done at the main hearing, the Board is of the view

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100 *Supra* note 94 at 4.

101 *Ibid.* at 4.

102 *Ibid.* at 6.

103 *Gas/Bitumen Production in Oil Sands Areas Application, Notification, and Drilling Requirements*, (3 February 1999) AEUB Interim Directive ID 99-1 (AEUB).

> that producing gas from the specific perforated intervals in the 10 wells ... could have a detrimental effect on bitumen recovery.[104]

In the Gulf Surmont decision,[105] the AEUB held that recovery becomes more difficult at pressures below 800 kPaa and the minimum pressure where bitumen recovery is possible is between 400 to 600 kPaa. In the present case, the evidence at the interim shut-in hearing was that pool pressures ranged from 335 to 1085 kPaa.[106] The AEUB was not prepared to consider artificial repressuring until field tests had been conducted to demonstrate that its implementation is both feasible and practical.[107]

The issue before the AEUB respecting "economics and public interest" was the economic impact of the amount of bitumen that might be sterilized compared with the cost of deferred gas production. The AEUB noted that the impact of a 75 kPaa drop in pressure over the course of one year on a single 30,000 bpd. SAGD project using a 10 percent discount rate would be two million barrels of unrecovered bitumen, $3 million of increased operating costs and reduced Crown royalties and pre-tax cash flow by about $7 million. The combined losses of four potential SAGD projects in the Chard area could be several times larger. In contrast, the value of pre-tax cash flow and royalties from all future gas production at Chard discounted at 10 percent would be approximately $40 million dollars. Deferral of this income for one year would result in a loss of approximately $4 million using a 10 percent discount rate.

In the result, the AEUB ordered shut-in of 10 out of the 40 gas wells for which Petro-Canada had requested shut-in. In doing so, the AEUB was careful to note that it would not be bound by its interim shut-in decision when ruling on Petro-Canada's application at the main hearing.

8. DECISION 2001-64: *FRANCO-NEVADA MINING CORPORATION INTERIM SHUT-IN OF GAS PRODUCTION 00/10-23-076-07W4M/0 WELL, LEISMER FIELD*[108]

On 9 and 10 July 2001, the AEUB heard an interim shut-in application made by Franco-Nevada Mining Corporation (Franco-Nevada) respecting an Anderson Exploration (Anderson) gas well (the 10-23 Well) in the Leismer field. Similar to the Petro-Canada interim shut-in application discussed above, the AEUB considered the geological interpretation, the effect of associated gas production on bitumen recovery by SAGD, the economics and public interest.

Based on interpretation of available well logs, the AEUB held that Wabiskaw gas at the 10-23 Well might be in communication with underlying bitumen. The highly variable nature of intervening sediments, lack of extensive correlatable mudstone units and the unpredictable nature of channel environments all suggested potential for vertical communication in the Leismer area. The AEUB also held that "bitumen within the Wabiskaw and McMurray sands

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104 *Supra* note 94 at 7.
105 *Gulf Surmont*, *supra* note 95.
106 *Supra* note 94 at 7.
107 *Ibid.*
108 (2 August 2001), AEUB Decision 2001-64 (AEUB).

on the Franco-Nevada lease is of sufficient quantity and quality to warrant consideration for protection pending the outcome of the main hearing."[109]

Based on Franco-Nevada's and Anderson's estimates of the current rate of pressure decline for the region of influence containing the 10-23 Well, the AEUB found that the pressure drop used for this interim review would be 260 kPaa, and not 1000 kpaa as proposed by Franco-Nevada. That would result in an approximate average pressure of 1415 kPaa one year from the date of an interim shut-in order. Such a reservoir pressure would be higher than the 800 kPaa pressure level that the AEUB concluded would make artificial lift more difficult. The AEUB held that Franco-Nevada did not demonstrate that there would be a significant loss of bitumen if gas production was permitted to continue in the interim period.[110]

With respect to the issue of economics and public interest, the AEUB noted that, based on a pressure drop of 1000 kPaa and a 10 percent discount rate, the combined economic losses including royalties, taxes and corporate profits would be approximately $4 million per well pair. Given that the drop in pressure over the year is expected to be only 260 kPaa, the economic effects in the interim period would be much less than $4 million.

In the result, the AEUB denied Franco Nevada's application because it was "not persuaded at this time that the impacts described by Franco-Nevada are significant enough to have a material effect on the economic desirability of the Franco-Nevada lease."[111] Again, the AEUB made it clear that it would not be bound by its interim shut-in decision when ruling on Franco-Nevada's application at the main hearing.

9. DECISION 2001-44: *NOVA GAS TRANSMISSION LTD., APPLICATION FOR APPROVAL OF THE ALBERTA SYSTEM RATE SETTLEMENT FOR 2001-2002*[112]

In Decision 2001-44, the AEUB approved Nova Gas Transmission Ltd.'s (NGTL) Alberta System Rate Settlement (the Settlement). The Settlement determined NGTL's revenue requirement for 2001 and 2002 at $1390 million plus non-routine adjustments and $1347 million plus non-routine adjustments, respectively. The AEUB also approved, consistent with the Settlement, interim tolls[113] as final respecting 1 January to 30 May 2001 final tolls for the remainder of 2001 and two new service offerings.[114]

The AEUB convened a written proceeding to consider the Settlement. No parties objected to approval of the Settlement in whole or in part. The AEUB applied a two-part analysis in assessing the Settlement. The first part was to determine if the AEUB should consider the Settlement in its entirety or various individual elements. The second part was a determination

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109 *Ibid.* at 3.
110 *Ibid.* at 5.
111 *Ibid.*
112 (29 May 2001), AEUB Decision 2001-44 (AEUB).
113 *NOVA Gas Transmission Ltd., Application for 2001 Interim Rates, Tolls and Charges* (19 December 2000), AEUB Decision 2000-80 (AEUB).
114 Point to Point Service, an intra-Alberta service from a specific receipt point to a specific delivery point available for the term of the Settlement, and One Year Nonrenewable Firm Transportation Receipt Service.

of whether the Settlement was in the public interest and reasonable and fair to all interested parties.

The Settlement was the product of negotiations among NGTL and a wide variety of stakeholders.[115] The AEUB found that NGTL complied with the AEUB's criteria for negotiated settlements[116] by including all affected parties in an appropriate forum where they could participate on a confidential and without prejudice basis and by providing proper notice and sufficient information to stakeholders. The AEUB also noted that parties "have negotiated the Settlement on the basis that it is acceptable to the Board in its entirety" and that it likely reflected a number of compromises made by the parties.[117] On that basis, the AEUB determined that it was appropriate to approve the Settlement as a whole and not examine individual components.

With respect to the second part of the analysis, the AEUB noted that there were no objections or concerns raised in response to the AEUB's public notice of NGTL's application and that diverse interests participated in the negotiation process. Accordingly, the AEUB found that "the Settlement reflects an appropriate balance of the interests of affected parties, and results in rates that are just, reasonable, and in the public interest."[118]

Other notable matters coming out of Decision 2001-44 include: including Fort McMurray delivery service costs, if subsequently approved by the AEUB, as a flow-through non-routine adjustment (see Part II.B.4 above); reserving to NGTL the right to offer load retention services in accordance with AEUB Decision U97096; requiring parties to the Settlement to negotiate an appropriate revenue requirement adjustment if NGTL divests more than $150 million of its assets on an annual aggregate basis; requiring NGTL to provide an annual audit report respecting the Settlement to the AEUB and NGTL's Tolls, Tariff and Procedures Committee; and recognizing the ongoing stakeholders' commitment to address a number of outstanding issues, including cost allocation among receipt, intra-Alberta and extra-Alberta deliveries, as well as finalizing an NGTL code of conduct.

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115 Signatories to the Settlement were NGTL, the Canadian Association of Petroleum Producers, North Core Committee (Canadian Forest Products Limited, City of Edmonton Consumers Coalition of Alberta, Federation of Gas Co-ops, Gas Alberta Inc., Municipal Intervenors, Public Institutional Consumers of Alberta, and Treaty 8 Aboriginal People), the Small Explorers and Producers Association of Canada, Gas Alberta Inc., the Industrial Gas Consumers Association of Alberta, Mirant Americas Energy Marketing Canada, Alberta Department of Resource Development (now Alberta Department of Energy), Pacific Gas and Electric Company, B.C. Gas Utility, Clan Duncan Resources, and Syncrude Canada. Stakeholders participating in the Settlement negotiations comprised an even larger group.

116 *Negotiated Settlement Guidelines – Tolls, Tariffs, and Terms and Conditions of Service* (15 May 1998), AEUB Information Letter IL 98-4 (AEUB).

117 *Supra* note 112 at 8.

118 *Ibid.* at 9.

10. DECISION 2001-48: *GULF CANADA RESOURCES LIMITED, APPLICATIONS FOR WELL LICENCES AND PIPELINES, VULCAN FIELD*[119]

Decision 2001-48 reflects the AEUB's concern that public consultations take place in a fair and complete manner to allow local landowners the opportunity to understand proposed energy projects and make informed decisions as to how such projects may affect them.

Crestar Energy (Crestar) applied to the AEUB for approval to drill three level-1 non-critical sour gas wells. Crestar's applications indicated that there were no residences within the calculated emergency planning zones and there were no outstanding public or industry objections to its applications. On that basis, the AEUB processed the well applications as "routine" and on 8 August 2000 issued Well License Nos. 0240543, 0240544, and 0240545 (the Well Licences) to Crestar. Crestar subsequently applied to the AEUB for approval to construct and operate gathering lines to tie-in those wells.

On 21 August 2000, local landowners (the Graffs) advised the AEUB that they opposed Crestar's proposed wells and pipelines because Crestar had not responded to objections set out in their letter dated 9 June 2000. The Graffs subsequently requested that the AEUB suspend the Well Licences and conduct a review hearing pursuant to s. 43 of the *Energy Resources Conservation Act*,[120] based on the allegation that the Graffs had an outstanding objection to Crestar's applications.

In response to the Graffs' submissions, the AEUB conducted an audit of Crestar's applications as contemplated in its Guide 56.[121] Based on Crestar's audit materials, the AEUB determined that the Graffs did indeed have an outstanding objection at the time Crestar made its well applications. Consequently, the AEUB suspended the Well Licences on the basis that Crestar's application did not comply with Guide 56 and placed Crestar on Level-3 of the AEUB's Enforcement Ladder. On 11 October 2000, the AEUB granted the Graffs' request for a review hearing and continued suspension of the Well Licenses pending the outcome of that hearing. In November 2000, Crestar and the Graffs participated in an unsuccessful mediation.

In February 2001, Crestar and Gulf Canada Resources (Gulf) amalgamated. In Decision 2001-48, the AEUB refers to the amalgamated entity as "Gulf/Crestar," but notes that Crestar was responsible for the activities surrounding the subject applications prior to the amalgamation. The AEUB convened the review hearing from 6 to 8 March 2001 and considered issues relating to the need for the wells and pipelines, public consultation and communication, as well as impacts on the intervenors (health and operational issues).

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119 (5 June 2001), AEUB Decision 2001-48 (AEUB).

120 R.S.A. 1985, c. E-11, s. 43(1) [now R.S.A. 2000, c.10, s. 40(1)]:

> A person affected by an order or direction made by the Board without the holding of a hearing may, within 30 days after the date on which the order or direction was made, apply to the Board for a hearing.

121 *Guide 56: Energy Development Application Guide* (October 2000), AEUB Guide 56, online: AEUB <www.eub.gov.ab.ca/bbs/products/guides/g56-v1.pdf>.

With respect to the issue of public consultation, it is apparent from Decision 2001-48 that there was significant mistrust and miscommunication between Gulf/Crestar and the Graffs. The Graffs took the position that Gulf/Crestar was well aware of their health concerns yet never met with them, as Gulf/Crestar indicated it would do in its public notification materials, nor did it follow up on their 9 June objection. The Graffs requested that the AEUB cancel the Well Licences.

Gulf/Crestar acknowledged that the Graffs' original objection had "not been noted" and that the consultation with the Graffs began in the mediation. Further, the lack of consultation resulted from the Graffs' mistrust arising out of prior dealings regarding another Gulf/Crestar well located on the Graffs' property. Because the Graffs advised Gulf/Crestar that they would not meet with company representatives and would only communicate in writing, a public communication process could not succeed. Gulf/Crestar noted that, notwithstanding that the operation proposals it made during mediation did not lead to an agreement, it still pursued many of them, presumably based on having gained a better understanding of the Graffs' concerns through mediation.

The AEUB provided the following useful reminder regarding the intent of a public consultation program in the context of its application process:

> The purpose of the public consultation process is to ensure that a proponent informs persons whose rights may be directly and adversely affected by a project so that they may voice their concerns and have them heard. The *consultation information must be detailed enough to permit these persons to assess the impact of the proposed project on themselves*. The Board notes that a proponent must attempt to address the concerns raised by these persons and if it cannot resolve the concerns raised, the *outstanding objection must be clearly disclosed in the application filed with the EUB*. Failure to fully disclose outstanding objections at the time of making an application may result in the suspension of licences if subsequently the public involvement questions on the application are found to be false or inaccurate.[122]

The AEUB found that Gulf/Crestar was fully aware of the Graffs' objection prior to making its applications and that such action was unacceptable. The Well Licences were suspended and additional enforcement action was taken as a result. The AEUB held that, in taking the enforcement action and granting the Graffs' request for a review hearing, it had effectively remedied the lack of consultation.[123]

Regarding the issue of communication, the AEUB went on to state that:

> [The AEUB] expects *applicants and interveners* to work together to ensure that concerns and complaints with respect to existing wells or facilities are addressed. Lines of communication must remain open. The Board expects operators to make a reasonable effort to communicate with stakeholders. Furthermore, the Board believes that *direct verbal and telephone contact is necessary for timely communication*. In that regard, the Board also notes that it would be in the stakeholders' best interest to cooperate and participate in the

122 *Supra* note 119 at 9 [emphasis added].
123 *Ibid.* at 10.

communication process if they want their concerns addressed in a timely manner and if they want early notification of industry activities.[124]

The AEUB held that, even though the Graffs requested only written communication sent by registered mail, that was not sufficient in the present case. Rather, verbal communication, at least by telephone, was required in order for Gulf/Crestar to provide the Graffs with notification of activities and address the Graffs concerns. The AEUB urged the Graffs to accept Gulf/Crestar's offer to provide an answering machine for this purpose and recommended that written communication continue as a follow up to document information exchanges.[125]

The AEUB also noted the Graffs' claim that their health problems were due to oil and gas operations in the area. Expert medical witnesses for both the Graffs and Gulf/Crestar agreed that the Graffs were ill. Those witnesses disagreed, however, as to the cause and nature of the illness. The AEUB held that "the resolution [of the Graffs' health problems] does not lie in the rescission of the well licences in question, since the Board is of the view that the wells can be drilled and operated safely and that the applied-for pipelines can be constructed and operated safely,"[126] and that the proposed mitigation measures would achieve that result. The AEUB further noted the lack of empirical evidence to support a correlation between the Graffs' illness and oil and gas activities, as well as the fact that environmentally triggered illnesses have yet to be recognized as a disease or distinct syndrome by the Alberta Heritage Foundation for Medical Research.

With respect to operational issues, the AEUB found Gulf/Crestar's management system required improvement, notwithstanding the numerous commitments made by Gulf/Crestar, such as inline testing, limiting flaring to well completion and clean-up, ambient air monitoring and a closed system design. The AEUB was concerned with ensuring that procedures were in place to identify, address, monitor and verify that response measures are taken relating to off-lease impacts. The AEUB required Gulf/Crestar to submit a summary and performance evaluation of its operations management system within one year.[127]

In the result, the AEUB held that it would reinstate the Well Licences after three months' time, to allow the Graffs a further opportunity to sell their farm, or on the date the Graffs moved, whichever was sooner. The AEUB also approved Gulf/Crestar's pipeline application.

124 *Ibid.*
125 *Ibid.* at 10-11.
126 *Ibid.* at 15.
127 *Ibid.* at 17-18.

C. CANADA-NEWFOUNDLAND OFFSHORE PETROLEUM BOARD

1. DECISION 2001.01: *HUSKY OIL OPERATIONS LIMITED AND PETRO-CANADA, APPLICATION FOR APPROVAL OF WHITE ROSE CANADA-NEWFOUNDLAND BENEFITS PLAN AND WHITE ROSE DEVELOPMENT PLAN*[128]

Proponents of projects in the Newfoundland offshore area are required under the *Canada-Newfoundland Atlantic Accord Implementation Act*[129] and the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*[130] (the *Newfoundland Accord Acts*) to obtain approval from the Canada-Newfoundland Offshore Petroleum Board (CNOPB). This legislation requires a proponent to obtain approval for both a benefits package and a development plan.

On 15 January 2001, Husky Oil Operations Limited and Petro-Canada (the Proponents) applied to the CNOPB for approval of the White Rose Canada-Newfoundland Benefits Plan (the Benefits Plan) and the White Rose Development Plan (the Development Plan). After an oral hearing which included a review under the CNOPB issued its Decision 2001.01, dated 26 November 2001. Decision 2001.01 is lengthy and deals with all aspects of the project. The following discussion summarizes the more general aspects of the project and does not attempt to detail all issues addressed.

The White Rose field was discovered in 1984. It is located approximately 350 kilometres east of St. John's, Newfoundland, on the eastern edge of the Jeanne d'Arc basin and contains both oil and natural gas deposits. The Proponents proposed to develop the South Avalon oil pool using a steel floating production storage off-loading vessel (FPSO) in conjunction with seabed completions. It is estimated that the total recoverable oil in the basin is 45 $10^6 m^3$ or 283 million barrels. Although the CNOPB estimates that the gas resources in the White Rose field are approximately 76.7 $10^9 m^3$ or 2.7 tcf, development of the gas resources did not form part of the application.

The *Newfoundland Accord Acts* contain provisions designed to ensure that resources offshore of Newfoundland are developed in such a way that benefits accrue to the province and to Canada. Canadian enterprises and individuals are to be provided full and fair opportunity to participate in the supply of goods and services, with first consideration going to those businesses located within Newfoundland. The goods and services must be competitive in terms of market price, quality and delivery.[131] As well, provisions in the *Newfoundland Accord Acts* require that first consideration for training and employment be given to residents of Newfoundland.[132]

The CNOPB assessed and approved the Benefits Plan in accordance with the requirements of the *Newfoundland Accords Acts*. The assessment of the Benefits Plan was divided into five major areas: office in the province; employment; research and development and employment

128 (26 November 2001), CNOPB Decision 2001.01 (CNOPB) [*White Rose*].
129 S.C. 1987, c. 3.
130 R.S.N.L. 1990, c. C-2 [*Canada-Newfoundland and Labrador Accord Implementation Act*].
131 *Supra* note 128 at 32-34.
132 *Ibid.* at 29-30.

and training; goods and services; and disadvantaged individuals and groups. In addition, it considered monitoring and reporting.

The Proponents opened an east coast regional office in St. John's in 1997. That office has responsibility for managing all operational aspects of the Proponents' programs on the Grand Banks. The CNOPB was satisfied that the regional office had the appropriate decision-making authority to manage the engineering, procurement, construction and operation of the project.[133]

With respect to employment, the CNOPB distinguished between the project's development and operating employment phases. The CNOPB was generally satisfied that the Proponents' employment-related policies met the requirements of the *Newfoundland Accord Acts* for the employment of Canadians and, in particular, residents of the province.[134] However, the CNOPB conditioned the approval requiring the Proponents to file a human resources plan within sixty days of project sanction that outlines in greater detail how human resource needs of both phases of the project will be met.[135]

The *Newfoundland Accord Acts* require the Proponents to make expenditures for research and development, as well as education and training, within Newfoundland.[136] The Benefits Plan identified the Proponents' financial support for the Centre for Cold Ocean Research and Engineering, Memorial University Seismic Imaging Consortium, Newfoundland Environmental Industries Association and Memorial University of Newfoundland. The CNOPB held that it would establish parameters, criteria and target levels for such expenditures.[137]

The Proponents committed to establishing programs for the early identification of human resource needs, pre-startup training for key offshore personnel, discipline-specific offshore operations training and using the existing training centres and infrastructure within Newfoundland. The CNOPB conditioned its approval by requiring the Proponents to submit for approval a plan regarding research and development and education and training within sixty days of project sanction.[138]

With respect to goods and services, the CNOPB held that the policies and procedures described in the Benefits Plan would ensure that Canadian goods and services would be given full and fair opportunity, with first consideration to goods and services from Newfoundland. However, the CNOPB attached several conditions to its approval relating to contractor/subcontractor obligations, reports concerning contracting activity, forecasts of development activity, competitive markets in Canada and the province, and bid evaluation.[139]

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133 *Ibid.* at 27-28.

134 *Canada-Newfoundland Atlantic Accord Implementation Act*, *supra* note 129; *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act*, *supra* note 130 at s. 45.

135 *Supra* note 128 at 28-30.

136 *Supra* note 134.

137 *Supra* note 128 at 30-31.

138 *Ibid.* at 30-31.

139 *Ibid.* at 32-34.

The CNOPB found that the Benefits Plan was deficient respecting the provision of opportunities to disadvantaged groups. While the Proponents' affirmative action program concerning women was found to be well developed, it failed to address other groups identified as disadvantaged, including Aboriginal people, persons with disabilities and visible minorities. The CNOPB's approval was conditioned such that the Proponents must file a report with the CNOPB at the time of project sanction outlining a revised approach to affirmative action.[140] The CNOPB placed a number of conditions on the approval to ensure that the Proponents monitor and are able to report to the CNOPB, governments and the public regarding the nature and level of economic activity associated with the White Rose project.[141]

The second aspect of Decision 2001.01 related to the Development Plan. The Development Plan set out the Proponents' interpretation of the geology and reservoir characteristics of the White Rose field. It provided estimates of hydrocarbon reserves, described the approach and facilities that will be used to recover those reserves and included a description of the environmental parameters governing the design of the facilities. The CNOPB also approved the Development Plan subject to several conditions.

The CNOPB's responsibility respecting the review of the Development Plan was to ensure that production facilities would be designed and operated having regard to safety and the protection of the environment, as well as to ensure that resources would be produced in accordance with good oilfield practice to maximize recovery and prevent waste. In Decision 2001.01, the CNOPB considered three main areas respecting the Development Plan: conservation of the resource; safety of operations; and protection of the environment.[142]

The White Rose field comprises several fault-bounded blocks and hydrocarbon pools. Exploration and delineation drilling have confirmed the presence of hydrocarbons in several of these fault blocks. The Proponents intended to develop the South Avalon oil pool and in future years to produce oil from the North and West Avalon pools. As well, natural gas could eventually be produced from these areas if it is economically viable to do so.[143]

The CNOPB approved the resource conservation aspects of the Development Plan. Although the original concepts, approaches and preliminary designs were accepted, there will be more detailed analysis as plans evolve and other specific approvals from the CNOPB are obtained for the execution of various components of the project. The CNOPB attached several conditions relating to resource conservation to the approval.[144]

The CNOPB also approved the safety aspects of the Development Plan relating to the production system, including structures, facilities, equipment, operating procedures and personnel. Several conditions were imposed on the approval, including: submission for approval of a safety plan with each application for development work authorization; development and documentation of detailed operation procedures; submission for approval

140 *Ibid.* at 34-35.
141 *Ibid.* at 35-36.
142 *Ibid.* at 3.
143 *Ibid.* at 4.
144 *Ibid.* at 3.

of a training proposal with respect to individuals employed on the FPSO and support craft; disconnect procedures; demonstration that the best practicable evacuation technology will be used on production and drilling installations; approval of the CNOPB for the configuration of the support vessel fleet; and functional specifications for stand-by vessels prior to contracting for those vessels. Further, the CNOPB required the Proponents to submit for approval a plan to document and track the suite of safety studies required for detailed design within ninety days of project sanction.[145]

The White Rose project was subjected to a comprehensive study pursuant to the *Canadian Environmental Assessment Act*.[146] The responsible authorities for the comprehensive study were the CNOPB, Environment Canada, the Department of Fisheries and Oceans and Industry Canada. The comprehensive study addressed a wide range of environment-related topics, including discharges and emissions, as well as the proposed Environmental Protection Plan (EPP). The operation of the offshore facilities will result in the emission of greenhouse gases, drilling discharges and production discharges (production and cooling water). The Proponents committed to ensuring that these routine discharges would be treated and disposed of in accordance with the NEB's *Offshore Waste Treatment Guidelines*[147] as amended.[148] The Proponents have also committed to investigating the feasibility of reducing chlorine use when treating cooling water.[149]

The White Rose operations are expected to emit approximately 370,000 tonnes (CO_2 equivalent) of greenhouse gases. This would represent approximately four percent of Newfoundland's emissions in 2000. The Proponents undertook to evaluate the potential for reducing such emissions through technological advances and operation procedures. They were directed to provide the CNOPB with a report on the technical and economic feasibility and review the feasibility every three years as part of its EPP.[150]

The EPP addresses many environmental matters and will form part of a more comprehensive Health, Safety and Environmental Loss Management System for the White Rose project. Various areas of environmental protection planning were considered by the CNOPB, including: environmental assessment methodology and follow-up; environmental effects monitoring (especially on seabirds); cumulative environmental effects monitoring; effects on fishing; and effects on third-party offshore observers. On the whole, the CNOPB indicated that the measures proposed in the EPP were consistent with the requirements under the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations*.[151]

On 11 June 2001, the federal Minister of the Environment determined that the project, with the proposed mitigation measures, was not likely to cause significant adverse environmental effects.

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145 *Ibid.* at 103-21.

146 S.C. 1992, c. 37.

147 National Energy Board, Canada-Newfoundland Offshore Petroleum Board and Canada-Nova Scotia Offshore Petroleum Board, *Offshore Waste Treatment Guidelines* (1996).

148 *Supra* note 128 at 124.

149 *Ibid.* at 127.

150 *Ibid.* at 125.

151 S.O.R./95-103; *White Rose, ibid.* at 130-40.

D. ARBITRATION BETWEEN NEWFOUNDLAND AND LABRADOR AND NOVA SCOTIA CONCERNING PORTIONS OF THE LIMITS OF THEIR OFFSHORE AREAS: AWARD OF THE TRIBUNAL IN THE SECOND PHASE[152]

Regulation and revenue-sharing of resources off the coasts of Nova Scotia and Newfoundland and Labrador are governed by "accord acts" between the federal government and the provinces of Nova Scotia and Newfoundland and Labrador.[153] Those Acts do not, however, define a boundary between the two provinces in the Laurentian channel seaward of the Cabot Strait. This unresolved boundary dispute may have had the effect of delaying energy developments in the offshore area.

In order to resolve the boundary dispute, the federal Minister of Natural Resources convened an Arbitration Tribunal pursuant to the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act* and the *Canada-Newfoundland Atlantic Accord Implementation Act.*[154] The Arbitration Tribunal was mandated to apply principles of international law that govern the delimitation of maritime boundaries, and its procedure involved two phases. The first phase determined that the boundary had not been resolved by agreement between the provinces. The second phase (this decision) was to establish the boundary line given that no agreement had been reached. The Arbitration Tribunal released its decision in the second phase on 26 March 2002.

Both Nova Scotia and Newfoundland and Labrador, for different reasons, took the position that the principles of international law applicable to the present dispute did not include Article 6 of the 1958 *Geneva Convention on the Continental Shelf.*[155] Article 6 would have imposed an equidistant boundary on each of the provinces. Despite the provinces' arguments, the Arbitration Tribunal ruled that, pursuant to general principles of international law, the *Geneva Convention on the Continental Shelf* and the 1982 *United Nations Convention on the Law of the Sea,*[156] which Canada has yet to ratify, the starting point for the delimitation of a maritime boundary is an equidistance line.

The Arbitration Tribunal established the equidistance line in three stages. The first stage was referred to as the Inner Area, which is roughly in the area of the Cabot Strait. The second stage, referred to as the Outer Area, extends eastward from the south end of the Inner area to the outer edge of the continental margin. The third stage extends northwest from the north end of the Inner Area, in the Gulf of St. Lawrence. The Inner Area and the area northwest of

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152 *Arbitration Between Newfoundland and Labrador and Nova Scotia Concerning Portions of the Limits of Their Offshore Areas, as Defined in the* Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act *and the* Canada-Newfoundland Altantic Accord Implementation Act, [Award of the Tribunal in the Second Phase], (26 March 2002).

153 *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*, S.N.S. 1983, c. 3, s. 1; *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*, S.C. 1988, c. 28; *Canada-Newfoundland Atlantic Accord Implementation Act*, S.C. 1987, c. 3; and *Canada-Newfoundland Atlantic Accord Implementation Newfoundland Act*, R.S.N.L. 1990, c. C-2.

154 S.C. 1988, c. 28, s. 48; S.C. 1987, c. 3, s. 6.

155 *Geneva Convention on the Continental Shelf* (29 April 1958) 499 U.N.T.S. 312 [entered into force 10 June 1964].

156 *United Nations Convention on the Law of the Sea* (10 December 1982).

it were dealt with by applying an equidistance line with certain adjustments. The Outer Area caused some discussion because of the presence of Sable Island.

Starting with an equidistance line, the Arbitration Tribunal considered whether Sable Island ought to be included in the coastline of Nova Scotia. The Arbitration Tribunal held that despite its Constitutional status as federal land,[157] Sable Island is rightly considered part of Nova Scotia's coastline. However, due to the island's distorting effect, the possible boundary should only be adjusted by half of Sable Island's normal impact. The Arbitration Tribunal went on to consider "the concern relat[ing] to the cut-off effect that the provisional line [had] on the southwest coast of Newfoundland."[158] The Arbitration Tribunal attempted to ensure that the boundary line did not come too close to the coast of either of the provinces. In the result, the Arbitration Tribunal entirely removed the effect of Sable Island and delimited the boundary accordingly.

To the extent that this boundary dispute had caused delay in developing offshore projects, the Arbitration Tribunal's decision clarifies for industry and regulators the respective jurisdictions of Nova Scotia and Newfoundland and Labrador regarding review and approval of such projects.

III. LEGISLATIVE DEVELOPMENTS

A. FEDERAL

1. *NATIONAL ENERGY BOARD ACT*[159]

The *National Energy Board Act* (*NEBA*) was amended by *An Act to Implement the Free Trade Agreement between the Government of Canada and the Government of Costa Rica*[160] to add Costa Rica as a country (similar to NAFTA countries) which is exempted from any NEB Regulations regarding export prices for oil and gas and services related to oil and gas.

2. *REGULATIONS AMENDING THE FEDERAL AUTHORITIES REGULATIONS*[161]

The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) was added to the list of federal authorities identified in the *Federal Authorities Regulations*.[162] As a result, an environmental assessment is required prior to the CNSOPB, as an administrator of federal lands, selling, leasing or otherwise disposing of federal lands or any interests in federal lands.

157 The *Constitution Act, 1867* (U.K.), 30 & 31 Vict., c. 3., reprinted in R.S.C. 1985, App. II, No. 5, established that the federal government has exclusive ownership and jurisdiction over Sable Island.

158 *Supra* note 152 at 5.15.

159 R.S.C. 1985, c. N-7.

160 S.C. 2001, c. 28.

161 S.O.R./2001-44.

162 S.O.R./96-280; issued pursuant to the *Canadian Environmental Assessment Act*, S.C. 1992, c. 37.

3. BILL 33, *NUNAVUT WATERS AND NUNAVUT SURFACE RIGHTS TRIBUNAL ACT*[163]

The *Nunavut Waters and Nunavut Surface Rights Tribunal Act* amends *the MacKenzie Valley Resources Management Act*[164] by making the *Northwest Territories Waters Act*[165] applicable to Inuit-owned lands designated under ss. 15.1 to 15.5 of the *Northwest Territories Water Act*, even if those lands are outside the MacKenzie Valley.

Bill C-33 also proposes to amend the *Canada Oil and Gas Operations Act*[166] by removing lands within the Yukon from s. 5.01, which deals with right of entry for exploring or exploiting oil and gas.

4. BILL C-19, *AN ACT TO AMEND THE CANADIAN ENVIRONMENTAL ASSESSMENT ACT*[167]

Bill C-19 proposes, among other things, to establish a federal environmental assessment co-ordinator for projects that are required to undergo screening or comprehensive study assessments. Also provided for is the creation of the Canadian Environmental Assessment Registry to provide public access to environmental assessment information respecting specific projects. In addition, the comprehensive study process will be amended to prevent a second environmental assessment of a project by panel review and to extend the participant-funding program to comprehensive studies. Bill C-19 has passed second reading and was referred to committee on 4 June 2001.

5. BILL C-5, *SPECIES AT RISK ACT*[168]

The intention of Bill C-5 is to prevent indigenous Canadian species from becoming extirpated or extinct. It provides for identification of endangered species by placing them on the List of Wildlife Species at Risk (the List). The starting point for the List will be the current list of the Committee on the Status of Endangered Wildlife in Canada (COSEWIC), which has several risk categories for identified species. Once a species is placed on the List, its habitat may be protected on federal lands. Habitat may also be protected in limited circumstances on provincial and private lands where the federal government determines that efforts by a province or the landowner have been insufficient to protect "critical habitat." In that case, the federal cabinet must pass regulations defining the habitat and the prohibited activities within that habitat.

Bill C-5 provides that the Minister compensate any person for losses suffered as a result of any extraordinary impact resulting from measures taken under Bill C-5 to protect critical habitat. Bill C-5 also provides for sizeable penalties for offences.

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163 S.C. 2002, c. 10.
164 S.C. 1998, c. 25.
165 S.C. 1992, c. 39.
166 R.S.C. 1985, c. O-7.
167 1st Session, 37th Parl., 2001.
168 1st Session, 37th Parl., 2001.

Bill C-5 has been and continues to be controversial and it is unclear whether it will be passed in its present form or if even further amendments are to come. Bill C-5 has been debated at the report stage in 2002.

B. ALBERTA LEGISLATION

1. R.S.A. 2000

The most comprehensive, and perhaps most inconvenient, amendments promulgated in the past year were the R.S.A. 2000, which saw a re-enactment of most Alberta statutes. Counsel should note that, notwithstanding its 1 January 2002 effective date, the R.S.A. 2000 does not incorporate amendments from 2001. Further care needs to be taken when reviewing past case law and regulatory decisions which refer to specific statute sections, as well as when researching the new statute sections, as most section numbers have changed.

2. *NATURAL GAS ROYALTY REGULATION, 1994 AMENDMENT REGULATION*[169]

The *Natural Gas Royalty Regulation, 1994*[170] was substantially amended in 2001. Changes were made in numerous areas, including definitions, formulas for determining royalty compensation and allowable costs. This legislation also amended a number of other regulations, such as the *Oil Sands Royalty Regulation, 1997*,[171] the *Natural Gas Marketing Regulation*[172] and the *Experimental Oil Sands Royalty Regulation.*[173]

3. *ORPHAN FUND DELEGATED ADMINISTRATION REGULATION*[174]

This new regulation creates the Alberta Oil and Gas Orphan Abandonment and Reclamation Association (the Association). Among other things, the regulation delegates to the Association various powers, duties and functions previously exercised by the AEUB, as well as the ability to deal with agreements and funds of the Association.

4. *ALBERTA ENERGY AND UTILITIES BOARD RULES OF PRACTICE*[175]

The AEUB has revised and consolidated its *Rules of Practice* to reflect the 1995 merger of the Energy Resources Conservation Board and the Public Utilities Board, each of which previously had their own set of rules. Some of the changes include confidential filing of documents in certain cases, swearing under oath or affirming witnesses giving testimony, review and variance applications, as well as pre-hearing, technical and settlement meetings.

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169 Alta. Reg. 156/2001.
170 Alta. Reg. 351/93; issued pursuant to the *Natural Gas Marketing Act*, R.S.A. 2000, c. N-1.
171 Alta. Reg. 166/84.
172 Alta. Reg. 358/86.
173 Alta. Reg. 347/92.
174 Alta. Reg. 45/2001.
175 Alta. Reg. 101/2001.

5. *SURFACE RIGHTS ACT*[176]

The *Surface Rights Amendment Act, 2001*[177] amends s. 30 of the *Surface Rights Act* by increasing the upper limit of compensation that the Surface Rights Board (SRB) can award to $25,000 for applications made on or after 1 July 2001.

The *Surface Rights Act General Regulation*[178] repeals and replaces the former general regulation.[179] The *Surface Rights Act Rules of Procedure and Practice*[180] repeal and replace the SRB's former *Rules of Procedure and Practice*.[181]

6. *ENERGY INFORMATION STATUTES AMENDMENT ACT, 2002*[182]

The *Energy Information Statutes Amendment Act, 2002* amends a number of energy statutes, including the *Coal Conservation Act*,[183] the *Mines and Minerals Act*,[184] the *Natural Gas Marketing Act*,[185] the *Oil and Gas Conservation Act*[186] and the *Oil Sands Conservation Act*.[187] The amendments result in the confidentiality provisions contained within the amended acts prevailing over the *Freedom of Information and Protection of Privacy Act*.[188]

7. *ADMINISTRATIVE PENALTIES AND RELATED MATTERS STATUTES AMENDMENT ACT, 2002*[189]

The *Administrative Penalties and Related Matters Statutes Amendment Act, 2002* amends the *Environmental Protection and Enhancement Act*,[190] the *Forests Act*,[191] the *Mines and Minerals Act*,[192] the *Public Lands Act*,[193] and the *Water Act*[194] by providing for or modifying existing administrative penalty schemes under those acts. This *Act* is only partially in force.

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176 R.S.A. 2000, c. S-24.
177 S.A. 2001, c. 12.
178 Alta. Reg. 189/2001.
179 Alta. Reg. 238/83.
180 Alta. Reg. 190/2001.
181 Alta. Reg. 293/83.
182 S.A. 2002, c. 12.
183 R.S.A. 2000, c. C-17.
184 R.S.A. 2000, c. M-17.
185 R.S.A. 2000, c. N-1.
186 R.S.A. 2000, c. O-6.
187 R.S.A. 2000, c. O-7.
188 R.S.A. 2000, c. F-25.
189 S.A. 2002, c. 4.
190 R.S.A. 2000, c. E-12.
191 R.S.A. 2000, c. F-22.
192 *Supra* note 184.
193 R.S.A. 2000, c. P-40.
194 R.S.A. 2000, c. W-3.

C. BRITISH COLUMBIA LEGISLATION

1. *PETROLEUM AND NATURAL GAS ROYALTY AND FREEHOLD PRODUCTION TAX REGULATION*[195]

The *Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation* was amended to revise definitions, as well as the formulas for calculating royalties and exemptions.

2. *PETROLEUM AND NATURAL GAS ROYALTY AND FREEHOLD TAX REGULATION*[196]

The *Petroleum and Natural Gas Royalty and Freehold Tax Regulation* was amended to add a definition for "coalbed methane project," revise the definition of "producer cost of service allowance" and add provisions creating a "coalbed methane producer cost of service bank" for each producer having an interest in one or more wells forming a part of a coalbed methane project.

3. *VANCOUVER ISLAND NATURAL GAS PIPELINE ACT*[197]

Section 3 of the *Vancouver Island Natural Gas Pipeline Act* has been amended to allow the Minister responsible to enter into agreements with B.C. Gas Inc., Centra Gas British Columbia, Westcoast Power Holdings, CGBC Holdings or any other person approved by the Lieutenant Governor in Council respecting funding, construction, operation of the pipeline, or granting of service areas.

4. *ENERGY AND MINES STATUTES AMENDMENT ACT, 2002*[198]

The *Energy and Mines Statutes Amendment Act, 2002* makes a number of significant amendments to B.C. energy statutes. Of note are the following amendments:

- *Ministry of Energy, Mines and Petroleum Resources Act*:[199] renames that Act to the *Ministry of Energy and Mines Act*, permits the Minister to authorize loans and investments for roads and other works, permits cost recovery for roads and other works used for resource exploration and development and permits regulations to be made respecting roads;

- *Oil and Gas Commission Act*:[200] provides that the Deputy Ministry of Energy and Mines is a director of and chairs the Oil and Gas Commission (OGC), authorizes the OGC as an agent of the government, sets the direction and management of the OGC and authorizes the issuance of general development permits which are approvals in principle for oil and gas activities and pipelines in B.C.;

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195 B.C. Reg. 495/92; issued pursuant to the *Petroleum and Natural Gas Act*, R.S.B.C. 1996, c. 361.
196 B.C. Reg. 29/2002; issued pursuant to the *Petroleum and Natural Gas Act*, R.S.B.C. 1996, c. 361.
197 R.S.B.C. 1996, c. 474.
198 S.B.C. 2002, c. 26.
199 R.S.B.C. 1996, c. 298.
200 S.B.C. 1998, c. 39.

- *Petroleum and Natural Gas Act*:[201] eliminates depth restrictions for drilling, permits regulations to be made governing geophysical exploration, sets the terms and renewals for geophysical licenses and specifies circumstances in which the OGC may exempt persons from the application of the regulations governing geophysical exploration.

The *Energy and Mines Statutes Amendment Act* received Royal Assent on 9 May 2002, but is not yet in force.

5. *WASTE MANAGEMENT AMENDMENT ACT, 2002*[202]

The *Waste Management Amendment Act, 2002* amends numerous provisions in the *Waste Management Act*[203] dealing with contaminated sites. It also amends the *Petroleum and Natural Gas Act*[204] by repealing and replacing s. 84.1, which addresses applications for certificates of restoration respecting a well, test hole or production facility.

D. SASKATCHEWAN LEGISLATION

1. *THE OIL AND GAS CONSERVATION ACT*[205]

An Act to Amend The Oil and Gas Conservation Act[206] makes amendments that will result in a number of changes to the *Oil and Gas Conservation Act*, including:

- provision of a framework for a comprehensive abandonment and reclamation liability management program respecting oil and gas wells, facilities and related sites. The Oil and Gas Orphan Program is modelled after a similar program in Alberta, builds on the provisions of the existing Oil and Gas Environmental Fund (now the Oil and Gas Orphan Fund);

- review of potential abandonment and reclamation liability, as well as provision of security;

- inclusion of new Ministerial powers to make orders respecting public safety and protection of property or the environment; and

- expansion of powers respecting the recovery of debt owing to the Minister.

Amendments to the *Oil and Gas Conservation Regulations, 1985*[207] will be required to implement fully the Oil and Gas Orphan Program. Although *An Act to Amend the Oil and*

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201 R.S.B.C. 1996, c. 361.
202 S.B.C. 2002, c. 34.
203 R.S.B.C. 1996, c. 482.
204 *Supra* note 201.
205 R.S.S. 1978, c. O-2.
206 S.S. 2001, c. 26.
207 R.R.S. c. O-2, Reg 1.

Gas Conservation Act has been passed, it will not be proclaimed in force until the regulation amendments have been issued.

2. *THE FREEHOLD OIL AND GAS PRODUCTION TAX AMENDMENT ACT, 2001* [208]

The Freehold Oil and Gas Production Tax Act was amended in June 2001[209] to add Part 3, entitled "Recovering Crude Oil." The amendments dealt with related definitions, crude oil tax, appeals of tax assessments, offences and penalties, and regulation-making powers.

3. *CROWN OIL AND GAS ROYALTY AMENDMENT REGULATIONS, 2001*[210] *AND THE FREEHOLD OIL AND GAS PRODUCTION TAX AMENDMENT REGULATIONS, 2001* [211]

The *Crown Oil and Gas Royalty Regulations*[212] and *The Freehold Oil and Gas Production Tax Regulations, 1995*[213] have been amended, adding provisions dealing with CO_2 enhanced oil recovery projects and a royalty scheme for CO_2 enhanced oil recovery projects.

4. *THE MINERAL RESOURCES ACT, 1985* [214]

The Mineral Resources Act, 1985 was amended by *The Mineral Resources Amendment Act, 2001*[215] which added provisions respecting mineral exploration tax credits, including related definitions, regulation-making power and recovery of excess credits.

5. *THE LAND TITLES ACT, 2000* [216]

The Land Titles Act, 2000 is a re-enactment and makes consequential amendments to a number of other Saskatchewan statutes. For example, *The Crown Minerals Act*[217] was amended to permit the Registrar of Titles to issue a new title, to register an interest against the title, or amend a title, or an interest, as the case may require, to register the transfer to and vesting of the oil and gas rights in the Crown where oil and gas rights were transferred to and vested in Her Majesty in Right of Saskatchewan pursuant to the *Oil and Gas Conservation, Stabilization and Development Act*,[218] and either no title was issued or no interest was registered against the title or a new title was issued, or an interest registered against the title and, in the opinion of the Minister, the title or interest requires an amendment. The oil and gas rights are deemed not to have been transferred to the Crown pursuant to the *Oil and Gas Conservation, Stabilization and Development Act*, where the transfer investing has not been

208 S.S. 1982-83, c. F-22.1.
209 S.S. 2001, c. 15.
210 S.R. 101/2001; issued pursuant to *The Crown Minerals Act*, S.S. 1984-85-86, c. C-50.2.
211 S.R. 102/2001; issued pursuant to *The Freehold Oil and Gas Production Tax Act*, S.S. 1982-83, c. F-22.1.
212 R.R.S. c. C-50.2 Reg 9.
213 R.R.S. c. F-22.1 Reg 1.
214 S.S. 1984-85-86, c. M-16.1.
215 S.S. 2001, c. 22.
216 S.S. 2000, c. L-5.1.
217 S.S. 1984-85-86, c. C-50.2.
218 R.S.S. 1978, c. O-3.

registered by the issuance of a new title, the registration of an interest against a title, or the amendment of a title or an interest.

E. NOVA SCOTIA LEGISLATION

1. *ACT TO AMEND THE ENERGY RESOURCES CONSERVATION ACT AND THE PIPELINE ACT*[219]

An Act to Amend the Energy Resources Conservation Act and the Pipeline Act amends both the *Energy Resources Conservation Act*[220] and the *Pipeline Act.*[221] Clauses 1 to 9 amend the *Energy Resources Conservation Act* by abolishing the Nova Scotia Energy Board. The duties and responsibilities of that board were reassigned to the Minister. The amendments also permit the Minister to establish advisory and *ad hoc* committees and retain experts in order to carry out his or her duties. Clauses 12 and 13 amend the *Pipeline Act* to replace the Nova Scotia Energy Board with the Nova Scotia Utility and Review Board.

2. *UNDERGROUND HYDROCARBONS STORAGE ACT*[222]

The *Underground Hydrocarbons Storage Act* repealed the *Gas Storage Exploration Act*[223] and provided for the designation and licencing of hydrocarbon storage areas in underground formations within Nova Scotia. It also deals with surface rights relating to hydrocarbon storage areas.

F. NEW BRUNSWICK LEGISLATION

1. *OIL AND NATURAL GAS ACT*[224]

The *Oil and Natural Gas Act* has seen a number of amendments,[225] including repeal of certain sections relating to grouping of licences to search, conversion on discovery, well location and production. New provisions respecting continuance and extension of leases were added.

G. NEWFOUNDLAND LEGISLATION

1. *PETROLEUM AND NATURAL GAS ACT*[226]

An Act to Amend the Petroleum and Natural Gas Act[227] makes various amendments to the provincial royalty scheme, including changes to royalty reservations, royalty shares, royalty

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219 S.N.S. 2001, c. 15.
220 R.S.N.S. 1989, c. 147.
221 R.S.N.S. 1989, c. 345.
222 S.N.S. 2001, c. 37 (not yet proclaimed in force).
223 R.S.N.S. 1989, c. 181.
224 S.N.B. 1976, c. O-2.1.
225 *An Act to Amend the Oil and Natural Gas Act*, S.N.B. 2000, c. 20.
226 R.S.N.L. 1990, c. P-10.
227 S.N.L. 2001, c. 41.

agreements and in-kind royalties. Other amendments dealing with assessments, fees, forms and penalties are also made.

2. *ENVIRONMENTAL PROTECTION ACT*[228]

The *Environmental Protection Act* received Royal Assent on 22 May 2002. It repealed and replaced the *Environment Act;* the *Environmental Assessment Act, 2000;* the *Pesticides Control Act;* the *Waste Management Act*; and the *Waste Material Disposal Act.*[229]

IV. POLICIES, DIRECTIVES AND GUIDELINES

A. NATIONAL ENERGY BOARD

1. MEMORANDUM OF GUIDANCE: *ELECTRONIC FILING*

On 18 February 2002, the NEB issued a Memorandum of Guidance respecting electronic filing of documents. Amendments to the *National Energy Board Rules of Practice and Procedure, 1995*[230] (the *NEB Rules*) to accommodate e-filing are required. In the interim, the NEB has, pursuant to its powers under s. 4 of the *NEB Rules*, indicated that the *NEB Rules* are varied to permit e-filing consistent with the provisions set out in the Memorandum of Guidance.

2. MEMORANDUM OF GUIDANCE: *CONSULTATION WITH ABORIGINAL PEOPLES*[231]

The NEB has recognized increasing interest in the potential effects that energy projects may have on Aboriginal and treaty rights. It has also recognized that the matter is complicated by the fact that it is a quasi-judicial tribunal and that the Crown has certain fiduciary obligations to Aboriginal peoples.

On 4 March 2002, the NEB issued a Memorandum of Guidance concerning consultation with Aboriginal peoples. The NEB stated that it would be inappropriate to impose upon it a fiduciary duty towards Aboriginal people as part of its decision-making process, given that it is an independent quasi-judicial decision-making body. Rather, consistent with case law,[232] the NEB stated as follows:

> [the NEB] has a responsibility to determine whether there has been adequate Crown consultation before rendering its decision in cases where the effect of the decision may interfere with an Aboriginal or treaty right.
>
> Therefore, in considering applications before it, the Board will require applicants to clearly identify the Aboriginal peoples that have an interest in the area of the proposed project and to provide evidence that there

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228 S.N.L. 2002, c. E-14.2.

229 S.N.L. 1995, c. E-13.1; S.N.L. 2000, c. E-14.1; R.S.N.L. 1990, c. P-8; S.N.L. 1998, c. W-3.1; R.S.N.L. 1990, c. W-4.

230 S.O.R./95-208.

231 (4 March 2002), Memorandum of Guidance (NEB).

232 *Quebec (A.G.) v. Canada (National Energy Board)*, [1994] 1 S.C.R. 159.

> has been adequate Crown consultation where rights pursuant to section 35 of the *Constitution Act, 1982* may be infringed if the Board approves the applied-for facilities.
>
> In such cases, applicants will be expected to contact the appropriate Crown department or agency to ensure that the requisite Crown consultations are carried out and to arrange for the information pertaining to those consultations to be filed with the Board. In the absence of such evidence, an application may be considered deficient by the Board or questions may be posed to the applicant to elicit the necessary information.[233]

The foregoing does not abrogate a project proponent's consultation duties owed to stakeholders, including Aboriginal peoples.

3. MEMORANDUM OF GUIDANCE: *NEGOTIATED SETTLEMENTS OF TRAFFIC, TOLLS AND TARIFFS*

Following its experience in RH-1-2001[234] (see Part II.A.3 above) the NEB is now in the process of reviewing its Guidelines for Negotiated Settlements of Traffic, Tolls and Tariffs. In RH-1-2001, TCPL had achieved a settlement with 13 of its stakeholders, but failed to get unanimous consent for the settlement. As the current guidelines require unanimous consent, a hearing was necessary to resolve the settlement process.

In January 2002, the NEB issued draft revised guidelines for comment. No changes have been proposed for non-contested settlements. The NEB has, however, processed a number of changes with respect to contested settlements. The proposed changes take into account three major considerations. The first consideration was developing a procedure for dealing with contested settlements that would allow for both an expeditious decision and respect for the rights of the minority parties. The second consideration was ensuring that there would be adequate information on the public record for the NEB to make an informed decision. Finally, the NEB indicated that there must be no fettering of its ability and discretion to make decisions regarding the public interest.

When dealing with an uncontested settlement the applicant would, under the new guidelines, be required to submit a summary of the process used to achieve the settlement as well as an explanation of the support for the settlement.

An applicant would be permitted to submit a settlement which it felt was supported by an adequate majority of shippers, along with an explanation as to why the NEB should accept the settlement. The NEB would then allow for comments by parties regarding whether the settlement should be accepted.

Under the proposed guidelines, the NEB would have a number of options to choose from, including accepting, modifying or rejecting the settlement. Another change under the proposed guidelines would be that both NEB members and NEB staff would be permitted to participate in the task force meeting. Their role would be subject to agreement of the task force parties.

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233 *Supra* note 15.

234 *Ibid.*

4. PRACTICE DIRECTION: *MEDIATION OF DETAILED ROUTE OBJECTIONS*

In August 2001, the NEB issued a Practice Direction regarding the mediation of detailed route objections. It outlined the process for resolving disputes between landowners and companies with regard to the routing of an international or interprovincial pipeline or power line. Some of the issues covered are time frames, information exchange, the relationship between the mediation and a public hearing, confidentiality and the role of the NEB staff in the mediation.

5. NEWS RELEASE, 18 MARCH 2002: *COLLABORATIVE APPROACH*

Following the NEB's *Practice Direction: Mediation of Detailed Route Objections*,[235] the NEB issued a news release in March 2002 indicating that it is seeking input on new approaches to resolving disputes. The NEB indicated that, through a collaborative approach, it hopes to be able to design dispute resolution processes that would meet the needs of all interested parties. A draft document and wider consultation is expected later in 2002.

B. NORTHERN PIPELINE ENVIRONMENTAL IMPACT ASSESSMENT AND REGULATORY CHAIRS COMMITTEE

1. *DRAFT COOPERATION PLAN FOR THE ENVIRONMENTAL IMPACT ASSESSMENT AND REGULATORY REVIEW OF A NORTHERN GAS PIPELINE PROJECT THROUGH THE NORTHWEST TERRITORIES*

On 6 January 2002, the Northern Pipeline Environmental Impact Assessment and Regulatory Chairs Committee[236] released a draft co-operation plan (the Plan) for comment. The Plan describes how, in principle, the boards and agencies comprising the Committee will co-ordinate their response to any proposal to build a major natural gas pipeline through the Northwest Territories.

The Plan reflects a "made in the North" process that would have the flexibility to consider a variety of development scenarios and include public participation in the project review. The criteria applied in developing the Plan included a desire for high quality environmental and socio-economic assessment, responsiveness to northerners' expectations for participation and involvement, reasonable and clear timelines and avoidance of duplication.

The Plan involves a framework based on an integrated Environmental Impact Assessment (EIA) process co-ordinated with the regulatory processes of the NEB, the Mackenzie Valley

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235 (7 August 2001), NEB Practice Direction (NEB).

236 The agencies involved in the development of the Cooperation Plan were: Mackenzie Valley Land and Water Board, Mackenzie Valley Environmental Impact Review Board, Gwich'in Land and Water Board, Sahtu Land and Water Board, NWT Water Board, Canadian Environmental Assessment Agency, National Energy Board, Environmental Impact Review Board for the Inuvialuit Settlement Region, Joint Secretariat for the Inuvialuit Settlement Region, Environmental Impact Screening Committee for the Inuvialuit Settlement Region, Inuvialuit Game Council, Inuvialuit Land Administration, Inuvialuit Land Administration Commission, Department of Indian Affairs and Northern Development. The Nominee of the Deh Cho First Nation to the Mackenzie Valley Land and Water Board, Government of the Northwest Territories and the Government of Yukon participated as observers.

Land and Water Board (MVLWB), the Northwest Territories Water Board (NWTWB), the Gwich'in Land and Water Board (GLWB) and the Sahtu Land and Water Board (SLWB).

Three agreements will give effect to the Plan: one agreement between the Inuvialuit and the federal Minister of the Environment; another between the Mackenzie Valley Environmental Impact Review Board (MVEIRB) and the federal Minister of the Environment; and another agreement among the regulatory agencies. Those agreements will provide specific details to the framework and outline the roles and responsibilities of each agency in the EIA and regulatory process. The highlights of the Plan include:

- a joint environmental impact assessment process that meets the requirements of the *CEAA*, the *Mackenzie Valley Resource Management Act* and the *Western Arctic Claim; the Inuvialuit Final Agreement*;
- a co-ordinated regulatory process between the NEB, MVLWB, GLWB, SLWB and NWTWB;
- co-ordinated EIA and regulatory hearings;
- consolidated information requirements developed for the EIA and regulatory components; and
- shared technical support resources.

The Plan is currently being revised to incorporate suggestions made during the public comment period. It is expected to be released within the next few months.

C. ALBERTA ENERGY AND UTILITIES BOARD

1. GUIDE 55: *STORAGE REQUIREMENTS FOR THE UPSTREAM PETROLEUM INDUSTRY*[237]

In December 2001, the AEUB issued a revised Guide 55, which identifies upstream petroleum industry storage requirements and sets technical requirements for storage practices. The new Guide 55 was made effective 1 January 2002. The storage devices addressed by Guide 55 include above-ground tanks, underground tanks, containers, lined earthen excavations and bulk pads. Oil sands mining operations and the underground cavern storage of natural gas are excluded from the scope of Guide 55.

Changes made to Guide 55 include the following:

- clarification of secondary containment requirements for small tanks and containers;
- additional requirements for the storage (in open-topped, non-metallic tanks) of produced water from shallow, low-pressure gas wells in the Milk River, Medicine Hat and Second White Specs pools;
- minor adjustment of dike capacity;
- additional requirements for double walled above-ground tanks;
- removal of the option to use single-walled underground tanks;

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237 (December 2001), AEUB Guide 55, online: AEUB <www.eub.gov.ab.ca/bbs/products/guides/g55.pdf>.

- removal of the option to use concrete as a primary containment in situations where liquids are being stored or where there is potential for leachate to be generated;
- consistent monthly monitoring of all leak detection systems;
- clarification of the criteria for surface discharge of collected surface run-on/run-off waters;
- additional procedures to remove storage tanks from service;
- clarification respecting integrity verification test frequency and inspections of underground tanks, above-ground tanks and lined earthen excavations installed prior to 1 January 1996; and
- further information on the types of integrity verification tests available for above-ground and underground tanks.

2. GUIDES 31A AND 31B: *GUIDELINES FOR ENERGY COST CLAIMS AND GUIDELINES FOR UTILITY COST CLAIMS*[238]

The AEUB has issued Guides 31A and 31B setting out new rules governing cost claims for energy and utility matters effective 1 August 2001. The Guides clarify the costs that will likely be accepted by the AEUB and the procedure for making a cost claim. The Guides provide a Scale of Costs for professional fees and disbursements.

Guide 31A applies to energy matters heard by the AEUB, including cost claims made by "local intervenors." It remains the case that industry participants do not qualify as local intervenors. Guide 31B applies to utility matters heard by the AEUB. Unlike energy matters, all participants in a utility matter may make a cost claim. Part 5 of the *Alberta Energy and Utilities Board Rules of Practice*[239] also prescribes the rules for making cost claims (see Part III.B.4 above).

3. INTERIM DIRECTIVE ID 2001-08: *REVISED LICENSEE LIABILITY RATING (LLR) PROGRAM AND ENERGY DEVELOPMENT LICENCE TRANSFER REQUIREMENTS*[240]

Over the past few years the AEUB and industry have worked together to refine the AEUB's orphan well program. ID 2001-08 introduces, among other things, new requirements for transferring facility licences and interim security deposits on facility sales. The new program became effective on 1 May 2002.

AEUB licensees should be aware that the revised LLR program will be used by the AEUB to evaluate licence transfer applications respecting certain oil and gas assets (excluding oil or gas transmission pipelines) and all licensees' LLRs on a monthly basis. Licence transfers respecting transactions involving a vendor or purchaser whose LLR would fall below 1.0 if the transaction proceeds will not be approved. Further, a licensee whose LLR falls below 1.0 on a monthly review will be required to provide a security deposit for the difference between its deemed assets and deemed liabilities. A licensee may be required to provide additional

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238 (June 2001), AEUB Guide 31A, online AEUB <www.eub.gov.ab.ca/bbs/products/guides/g31A.pdf> and (June 2001), AEUB Guide 31B, AEUB <www.eub.gov.ab.ca/bbs/products/guides/g31B.pdf>.

239 Alta. Reg. 101/2001.

240 (4 December 2001), AEUB Interim Directive 2001-08, online: AEUB <www.eub.gov.ab.ca/bbs/requirements/ils/ids/id2001-08.htm>.

security deposits or may be eligible for deposit refunds depending on each future monthly LLR assessment. The AEUB intends to conduct a formal review of the revised LLR program in conjunction with stakeholders within twelve to eighteen months of implementing the program.

4. INTERIM DIRECTIVE ID 2001-06: *ELECTRONIC SUBMISSION OF LICENCE TRANSFER APPLICATIONS, WELL NAME CHANGE NOTIFICATIONS, FACILITY ABANDONMENT NOTIFICATIONS, AND LINKED FACILITY NOTIFICATIONS*[241]

ID 2001-06 introduces the requirement for a licensee to submit well, facility, and pipeline transfer applications, well name-change notifications, facility abandonment notifications and linked facility notifications electronically through the AEUB's digital data submission (DDS) system. Effective 1 January 2002, electronic submission of the above-mentioned applications and notifications was made mandatory. The DDS system is accessed through the AEUB's website (www.eub.gov.ab.ca).

5. INTERIM DIRECTIVE ID 2001-05: *PUBLIC SAFETY AND SOUR GAS POLICY IMPLEMENTATION RECOMMENDATIONS 54, 60, AND 61 SITE-SPECIFIC EMERGENCY RESPONSE PLANS FOR SOUR OPERATIONS, EMERGENCY PLANNING ZONES, AND REDUCED PLANNING ZONES*[242]

ID 2001-05 sets out the current requirements for site specific emergency response plans (ERP) for sour gas facilities. The AEUB is currently reviewing ERP requirements for sour facilities, including the methodology for calculating emergency planning zones, with a view to issuing a comprehensive ERP guide. ID 2001-5 introduced some new ERP requirements and became effective on 14 August 2001.

6. INTERIM DIRECTIVE ID 2001-04: *FINANCIAL SECURITY FOR OILFIELD WASTE MANAGEMENT FACILITIES*[243]

ID 2001-04 supersedes and replaces ss. 20.0 to 20.7 of Guide 58: *Oilfield Waste Management Requirements for the Upstream Petroleum Industry.*[244] It introduces changes to the AEUB's requirements for financial security respecting oilfield waste management facilities and limits the forms of acceptable financial security to those set out in AEUB ID 2001-01[245] (see Part IV.C.8 below). Any facility that holds or requires an AEUB oilfield waste management facility approval is required to post financial security. Separate financial security will not be required under ID 2001-04 respecting waste management components integrated into another AEUB approved or licensed production system.

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241 (19 October 2001), AEUB Interim Directive 2001-06, online: AEUB <www.eub.gov.ab.ca/bbs/requirements/ils/ids/id2001-06.htm>.

242 (14 August 2001), AEUB Interim Directive 2001-05, online: AEUB <www.eub.gov.ab.ca/bbs/requirements/ils/ids/id2001-05.htm>.

243 (24 July 2001), AEUB Interim Directive 2001-04, online: AEUB <www.eub.gov.ab.ca/bbs/requirements/ils/ids/id2001-04.htm>.

244 (November 1996), AEUB Guide 58, online: AEUB <www.eub.gov.ab.ca/bbs/requirements/Guides/g58.htm>.

245 *Infra* note 248.

ID 2001-04 contemplates a three-stage phase-in for the program. Effective 15 September 2001, approval holders were required to post financial security to cover costs associated with the suspension of their facilities. Effective 15 September 2004, approval holders will be required to post additional financial security to cover costs associated with abandonment. Effective 1 September 2006, approval holders will be required to post further financial security to cover costs associated with decontamination and surface land reclamation.

7. INTERIM DIRECTIVE ID 2001-03: *SULPHUR RECOVERY GUIDELINES FOR THE PROVINCE OF ALBERTA*[246]

The AEUB and AENV have reviewed the sulphur recovery guidelines for sour gas plants. ID 2001-03 sets out revised guidelines and provides details of measures that will be implemented respecting sour gas plants, other upstream petroleum facilities and downstream petroleum operations, including refineries and heavy oil and bitumen upgraders. ID 2001-03 became effective on 1 January 2002 and replaces AEUB Information Letter IL 88-13: *Sulphur Recovery Guidelines — Gas Processing Operations* in its entirety. ID 2001-03 operates in conjunction with AEUB Guide 60: *Upstream Petroleum Industry Flaring Guide.*[247]

Consideration is given in ID 2001-03 to grandfathered facilities. Grandfathered sour gas plants, related baseline capacities and grandfathered sulphur recovery efficiencies are identified in Appendix 1. ID 2001-03 also applies to upstream petroleum industries, other than sour gas plants that were approved prior to 1 January 2002, on the same basis and in the same time frame as established for grandfathered sour gas plants. Operators of grandfathered sour gas plants are encouraged to take cost-effective measures early to enhance sulphur recovery beyond the minimum requirements through bankable sulphur emission reduction credits for recovery performance that exceeds requirements. Operators may apply for variance of the guideline sulphur recovery levels or of the manner in which the guidelines are applied to specific situations.

8. INTERIM DIRECTIVE ID 2001-01: *SECURITY DEPOSITS*[248]

This interim directive, effective 12 April 2001, outlines acceptable forms of security deposits for potential abandonment and reclamation liabilities. It updates and replaces ID 2000-02: *Security Deposits — Acceptable Forms of Security*. Only renewable, irrevocable letters of credit (LC) in the exact form outlined in ID 2001-01, issued by the Alberta Treasury Branch or financial institutions identified in Schedules I and II of the *Bank Act*,[249] are acceptable. An LC must stipulate that renewal is automatic without amendment. The LC must provide that where the issuer elects not to renew, it must notify the AEUB 60 days prior to

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[246] (29 August 2001), AEUB Interim Directive 2001-03, online: AEUB <www.eub.gov.ab.ca/bbs/requirements/ils/ids/id2001-03.htm>.

[247] (February 2001), AEUB Guide 60, online: AEUB <www.eub.gov.ab.ca/bbs/requirements/Guides/g60.htm>.

[248] (12 April 2001), AEUB Interim Directive, 2000-01, online: AEUB <www.eub.gov.ab.ca/bbs/requirements/ils/ids/id2001-01.htm>.

[249] S.C. 1991, c. 46.

expiry of the LC. Existing cash security with the AEUB may be converted into LCs. LCs must be revised to reflect certain changes, such as a licensee name change or amalgamation.

9. GENERAL BULLETIN GB 2001-21: *A NEW AEUB APPLICATION REGISTRY*[250]

GB 2001-21 introduces the new application registry for energy and utility applications available on the AEUB website (www.eub.gov.ab.ca). The registry contains most applications filed with the AEUB since July 2001 and the status of such applications.

[250] (27 November 2001), AEUB General Bulletin 2001-21, online: AEUB <www.eub.gov.ab.ca/bbs/requirements/ils/gbs/gb2001-21.htm>.