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

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This article examines legislative and regulatory developments that have occurred from May 1998 through April 1999 that are relevant to oil and gas lawyers. The emphasis is on federal and Alberta legislative amendments. Regulatory decisions of federal, Alberta, British Columbia, and Nova Scotia boards are reviewed and their application to oil and gas matters are discussed.

Les auteurs se penchent sur les faits saillants de l'évolution de la législation et de la réglementation pertinentes pour les spécialistes du droit minier — de mai 1998 à avril 1999. Ils s'intéressent surtout aux modifications apportées aux lois de l'Alberta et du Canada. Ils examinent les décisions des commissions fédérale, albertaine, britanno-colombienne et néo-écossaise; et traitent de leur application dans le secteur pétrolier et gazier.

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I. INTRODUCTION

The purpose of this article is to discuss legislative and regulatory developments that have occurred during the period of May 1998 through April 1999 and which are of particular interest to oil and gas lawyers. With respect to legislative developments, amendments to selected statutes and regulations as well as notable bills are discussed, with particular emphasis placed on federal and Alberta legislative developments although noteworthy developments in other jurisdictions are also discussed. With respect to regulatory developments, the discussion focuses primarily on decisions of the National Energy Board and Alberta Energy and Utilities Board although relevant decisions of other regulatory bodies, such as the Canada-Nova Scotia Offshore Petroleum Board, the British Columbia Utilities Commission, and the British Columbia Oil and Gas Commission, are also examined.

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II. LEGISLATIVE DEVELOPMENTS

A. FEDERAL LEGISLATION

1. *CANADA PETROLEUM RESOURCES ACT*[1]

The *Canada Petroleum Resources Act* was amended by Bill C-8, the *Canada-Yukon Oil and Gas Accord Implementation Act.*[2] Subclause 13(1) (which comes into effect on the transfer date as defined in s. 19), amends the definition of "frontier lands" in s. 2 of the *Canada Petroleum Resources Act* to include the Northwest Territories and Sable Island, but excludes the adjoining area as defined in s. 2 of the *Yukon Act.*[3] This has the effect of re-defining the natural resource areas that the Crown is able to exploit. Clause 117.1 was also added to divide exploration license 329, discovery license 12, and oil and gas leases 411-68 and 442-R-68.

2. *CANADIAN ENVIRONMENTAL ASSESSMENT ACT*[4]

The *Canadian Environmental Assessment Act* was amended by Bill C-6, the *Mackenzie Valley Resource Management Act.*[5] This amendment provides that where a proposal has been referred pursuant to the *Mackenzie Valley Resource Management Act*, the minister shall now refer the proposal to a review panel. Additionally, where a panel is required, the minister and the Mackenzie Valley Environmental Impact Review Board shall jointly establish a review panel that must consider the conflict of interest provisions set out in subclauses 16(1) and 16(2).

3. *NATIONAL ENERGY BOARD ACT*[6]

a. *Rules Amending the National Energy Board Rules of Practice and Procedure, 1995 (Miscellaneous Program)*[7]

The amendment to the Rules corrects non-substantive problems identified by the National Energy Board to address, for example, discrepancies between the English and French versions of the *National Energy Board Rules of Practice and Procedure, 1995.*[8]

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1 R.S.C. 1985 (2d Supp.), c. 36.

2 Bill C-8, *An Act respecting an accord between the Governments of Canada and the Yukon Territory relating to the administration and control of and legislative jurisdiction in respect of oil and gas*, 1st Sess., 36th Parl., 1997-98 (assented to 12 May 1998, S.C. 1998, c. 5).

3 R.S.C. 1985, c. Y-2.

4 S.C. 1992, c. 37.

5 Bill C-6, *An Act to provide for an integrated system of land and water management in the Mackenzie Valley, to establish certain boards for that purpose and to make consequential amendments to other Acts*, 1st Sess., 36th Parl., 1997-98 (assented to 18 June 1998, S.C. 1998, c. 25) [hereinafter *Mackenzie Valley Resource Management Act*].

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

7 SOR/98-355.

8 SOR/95-208.

4. *CANADA OIL AND GAS OPERATIONS ACT*[9]

The *Canada Oil and Gas Operations Act* was also amended by Bill C-8, the *Canada-Yukon Oil and Gas Accord Implementation Act*. Clause 11 amends the definition of "frontier lands" in paragraph 3(a) of the *Canada Oil and Gas Operations Act* to include the Northwest Territories and Sable Island but excludes the adjoining area as defined in s. 2 of the *Yukon Act*.[10] Clause 12 provides that where a person occupies an area under the jurisdiction of this Act, other than where the National Energy Board has granted authorization with respect to work or activity proposed to be carried on, no person can enter or use the surface lands except with the occupier's consent or in accordance with a decision of an arbitrator under the regulations. Clauses 11 and 12 will come into force when the first order of the Governor-in-Council is made pursuant to the *Yukon Act* transferring the administration and control of oil and gas to the Commissioner of the Yukon Territory.

5. *YUKON SURFACE RIGHTS BOARD ACT*[11]

a. *Order Amending Schedule I to the Yukon Surface Rights Board Act*[12]

An *Order Amending Schedule I to the Yukon Surface Rights Board Act* came into force on 16 December 1998, whereby land claims and self-government agreements have now been added to the jurisdiction of the Yukon Surface Rights Board. This amendment allows for issues of access to be resolved in the context of First Nations lands generally. Specifically, the order was approved to include the Little Salmon/Carmacks First Nation and the Selkirk First Nation.

6. *CANADIAN ENVIRONMENTAL PROTECTION ACT*[13]

a. Proposed *Sulphur in Gasoline Regulations*[14]

The Department of Environment, under the *Canadian Environmental Protection Act*, has proposed *Sulphur in Gasoline Regulations* with the stated goal of protecting the environment and health of Canadians. The proposed regulations would limit sulphur in gasoline to an average level of thirty parts per million (ppm), with an upper limit of eighty ppm. Low sulphur gasoline would be phased in across Canada in graduated stages with a 1 January 2005 target date for full implementation.

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9 R.S.C. 1985, c. O-7.
10 *Supra* note 3.
11 S.C. 1994, c. 43.
12 SOR/99-14.
13 R.S.C. 1985 (4th Supp.), c. 16.
14 C. Gaz. 1998.I.2989.

b. Proposed *Regulations Amending the Benzene in Gasoline Regulations*[15]

The *Benzene in Gasoline Regulations* were published in the Canada Gazette, Part II, on 26 November 1997. These regulations control the level of benzene in gasoline. Shortly after the passage of these regulations, the Canadian Petroleum Products Institute informed Environment Canada that compliance with the implementation date of 1 July 1999, would be impossible for some refiners. The proposed regulations therefore allow refiners, blenders, and importers of gasoline to apply for a temporary alternative limit for benzene in gasoline until the end of 1999.

7. *MACKENZIE VALLEY RESOURCE MANAGEMENT ACT*

The *Mackenzie Valley Resource Management Act* was assented to on 18 June 1998, and was proclaimed in force, excluding Part 4 and subsections 160(2), 165(2), and 167(2), on 22 December 1998.[16] Generally, this Act provides for an integrated system of land and water management in the Mackenzie Valley and the establishment of boards for that purpose. The Mackenzie Valley Land and Water Board will be established with jurisdiction for all land or water use or deposits of waste in the Mackenzie Valley for which a permit is required under the Act, or where a license is required under the *Northwest Territories Waters Act*.[17] The board will exercise its powers in relation to a use of land or waters or a deposit of waste that is to take place, and that is likely to have an impact on the settlement area as defined in the Act.

The Act will also establish the Mackenzie Valley Environmental Impact Review Board. This review board will be integral to the process of preliminary screening, environmental assessment, and environmental impact review in relation to proposals for developments to ensure that the impact on the environment of proposed developments receives careful consideration before actions are taken and that the concerns of aboriginal people and the general public are considered in the process.

8. *CANADIAN ENVIRONMENTAL PROTECTION ACT, 1998*[18]

As with the previous *Canadian Environmental Protection Act*, the goal of the proposed Act, the *Canadian Environmental Protection Act, 1998*, is to prevent pollution and to protect the environment and human health in Canada in order to contribute to sustainable development.

This bill will repeal and replace the *Canadian Environmental Protection Act*. Among the changes are provisions to implement pollution prevention, new procedures for the investigation and assessment of substances, new requirements with respect to substances

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15 C. Gaz. 1999.I.219.

16 S.I./99-1, C. Gaz. 1999.II.349.

17 S.C. 1992, c. 39.

18 Bill C-32, *An Act respecting pollution prevention and the protection of the environment and human health in order to contribute to sustainable development*, 1st Sess., 36th Parl., 1997-98-99 (2d reading 28 April 1998; in force on proclamation).

that the Minister of Environment and the Minister of Health have determined to be toxic or capable of becoming toxic within the meaning of Part 5, and provisions regarding animate products of biotechnology. The bill also contains new provisions respecting fuels, international air and water pollution, motor emissions, nutrients whose release into water can cause excessive growth of aquatic vegetation and environmental emergencies, provisions to regulate the environmental effects of government operations and to protect the environment on and in relation to federal land and aboriginal land, disposal of wastes and other matter at sea, and the export and import of wastes.

The bill provides for the gathering of information for research and the creation of inventories of data, which are designed for publication, and for the development and publishing of objectives, guidelines, and codes of practice. The bill also provides new powers for enforcement officers and analysts appointed by the Minister of Environment to enforce the law. Environmental protection alternative measures and environmental protection compliance orders provide new mechanisms for the resolution of a contravention. The bill also specifies criteria for courts to consider when imposing a sentence on an offender.

In addition, the bill contains new rights for Canadians who, through written comments or notices of objection to the Minister of Environment, may participate in decisions on environmental matters, may compel the minister to investigate an alleged contravention of the Act, and may bring civil actions when the federal government is not enforcing the law. Aboriginal governments are provided the right of representation on the National Advisory Committee to be established under the enactment and, like the provinces and territories, may seek to have their laws declared equivalent to the new regulations.

Of specific interest are the new provisions in Part 7, Division 4 ("Fuels"). Clause 139 provides a general prohibition that no person shall produce, import, or sell fuel that does not meet the requirements of the regulations.[19] However, there will be no contravention of this provision if the fuel is: in transit through Canada; produced or sold for export (and evidence to show that it will be exported); being imported with written evidence showing compliance with the regulations; or imported in a fuel tank that supplies an engine used for land, air, or sea transportation. There is also discussion of the introduction of national fuel marks that will evidence the fact that a prescribed fuel has been authorized by the minister, conforms with the applicable regulations (where evidence has been obtained), and that information has been provided to the minister, as provided in the regulations. No person shall be able to import or transport within Canada a prescribed fuel if a national fuel mark is not obtained.

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19 The Governor-in-Council, on the recommendation of the minister, has wide discretion to make regulations respecting: concentrations of an element, component, or additive in fuel; physical or chemical properties of fuel; transfer and handling of fuel; record keeping; auditing records; submission requirements; and conduct of sampling, analysis, testing, measuring of fuels, and additives.

Part 7, Division 5 ("Vehicle, Engine and Equipment Emissions") sets up procedures for national emission marks. Clause 152 states that no company shall transport, within Canada, a prescribed vehicle (to be prescribed in regulations), engines, or equipment that does not have a national emissions mark applied to it.[20] Section 156 allows applications by companies to be exempt from the emission standard applicable.

This Act will come into force on royal assent, except for clause 45, which will come into force on proclamation.

9. *FIRST NATIONS LAND MANAGEMENT ACT*[21]

Bill C-49, the *First Nations Land Management Act*, *inter alia*, allows for a First Nation to establish a land management regime and to adopt a land code applicable to all the land contained in a reserve of the First Nation.[22] After the land code is brought into force under the provisions of the proposed Act, the First Nation will have the power to manage the land, and in particular, it may: exercise the powers, rights, and privileges of an owner in the land; grant interests in and licenses to that land; manage the natural resources of that land; and receive and use all moneys acquired by or on behalf of the First Nation under its land code. The *Indian Oil and Gas Act*[23] will continue to apply in respect of any First Nation land that was subject to that Act on the coming into force of the land code of a First Nation. The *IOGA* will also continue to apply in respect of an interest in First Nation land that is granted to the Crown, including royalties paid to the Crown in trust for a First Nation, and for the exploitation of oil and gas pursuant to a land code.

10. *CANADA-YUKON OIL AND GAS ACCORD IMPLEMENTATION ACT*

Generally, the *Canada-Yukon Oil and Gas Accord Implementation Act* establishes legislative jurisdiction for and administration and control of oil and gas in the Yukon Territory in its amendment of the *Yukon Act*. The Act gives authority to the Commissioner-in-Counsel to make ordinances in relation to the exploration for oil and gas in the Yukon Territory, the development, conservation, and management of oil or gas in the Yukon Territory, including ordinances in relation to the rate of primary production, and oil and gas pipelines within the Yukon. Additionally, the Commissioner-in-Counsel may make ordinances in relation to the export of primary production from oil or gas within the Yukon to other parts of Canada. The Act also provides for a restricted ability of the Commissioner-in-Council to raise money through taxation ordinances in respect of oil or gas in the Yukon.

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20 Section 153 sets out the conditions under which a national emissions mark will be applied.

21 Bill C-49, *An Act providing for the ratification and the bringing into effect of the Framework Agreement on First Nation Land Management*, 1st Sess., 36th Parl., 1997-98-99 (1st reading in Senate 9 March 1999).

22 The requirements of the land code are set out at cls. 6(1)-6(3).

23 R.S.C. 1985, c. I-7 [hereinafter *IOGA*].

The Act further amends the *Yukon Act,* for the purposes of the settlement of an aboriginal land claim. The Governor-in-Council may, on the recommendation of the minister, take over administration and control of any oil and gas in public lands from the commissioner. Before doing so, however, the minister must consider any views with respect to the proposed settlement from the territorial oil and gas minister.

11. *NUNAVUT WATERS AND NUNAVUT SURFACE RIGHTS TRIBUNAL ACT*[24]

Bill C-62, the proposed *Nunavut Waters and Nunavut Surface Rights Tribunal Act,* establishes the Nunavut Surface Rights Tribunal. The tribunal will receive applications from individuals who have a mineral right granted by the Crown in relation to Inuit-owned land but who have been unable to obtain the consent of the applicable Inuit organization. The tribunal shall make an entry order that sets out the terms and conditions for the use and occupation of the land. As with other surface rights boards or tribunals, the tribunal will resolve any matters in regard to appropriate compensation for crossing or occupation of surface lands.

B. PROVINCIAL LEGISLATION

1. ALBERTA LEGISLATION

a. *Environmental Protection and Enhancement Amendment Act, 1998*[25]

The *Environmental Protection and Enhancement Act*[26] was amended by the *Environmental Protection and Enhancement Amendment Act, 1998.* The amendments contained within the new Act deal mainly with clarification of definitions, administrative matters, and a small number of substantive issues.

Of particular interest is the inclusion of a "working interest participant" in the definition of "operator," which would bring a working interest participant under the duties of an operator in Part 5 of the Act regarding conservation and reclamation. Further, the Act is amended so that a court may extend a limitation period for the commencement of a civil proceeding where the basis for the proceeding is an alleged adverse effect resulting from the alleged release of a substance into the environment. Depending on the interpretation by the courts, this amendment has the potential for expanding the lifespan of liability for the clean-up of contaminated sites. This amendment appears to introduce the concept of discoverability into environmental offences with no ultimate limitation period.

Also of note is the clarification of who should report a release. Section 99 of the Act was amended so that a person who releases, causes, or permits the release of a

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[24] Bill C-62, *An Act respecting the water resources of Nunavut and the Nunavut Surface Rights Tribunal and to make consequential amendments to other Acts,* 1st Sess., 36th Parl., 1997-98 (1st reading 4 December 1998).

[25] S.A. 1998, c. 15.

[26] S.A. 1992, c. E-13.3.

substance into the environment that has caused or may cause an adverse effect, shall, as soon as the person knows (or ought to know) of the release, report it to the director, the owner of the substance, the reporter's employer, the person who has control of the substance, and any other person the reporter knows or ought to know may be directly affected by the release.

Section 62.1 and s. 123(1.1) allow the director to refuse to issue approvals or registrations and allow inspectors to refuse to issue reclamation certificates where the applicant owes money to the Crown.

The remainder of the provisions assist the government in recovering costs of clean-ups, clarify the access to information provisions, revise some waste and land reclamation provisions, add the ability to appeal some additional decisions to the Environmental Appeal Board, and add regulation-making powers.

b. *Surface Rights Amendment Act, 1999*[27]

The *Surface Rights Amendment Act* amends the *Surface Rights Act*[28] primarily to address issues of compensation. Section 39 of the *Surface Rights Act* provides that, when an operator fails to pay money under a compensation order or surface lease, the board, upon application to it may direct the provincial treasurer to pay out of the General Revenue Fund ("GRF") the amount the individual is entitled. A debt is then owed for such amount by the operator to the Crown.

The Act will be changed so that when the board receives satisfactory proof of the non-payment by the operator, the board shall send a written notice to the operator demanding full payment. If payment is not forthcoming from the operator, the board may suspend the operator's right to enter the site or may completely terminate the operator's right of entry. Only where the operator's rights have been completely terminated may the board subsequently direct payment from the GRF. In this situation, the payments out of the GRF by the provincial treasurer may continue for any future non-payments by the operator without further application. The board may direct the provincial treasurer not to make any further payments if it considers that the person entitled to receive them is refusing access for operations, abandonment, or reclamation, which is allowed by law.

This Act was assented to on 23 March 1999, and comes into force on 1 September 1999.

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[27] Bill 4, *Surface Rights Amendment Act*, 3d Sess., 24th Leg., Alberta, 1999 (S.A. 1999, c. 5).

[28] S.A. 1983, c. S-27.1.

c. *Water Act*[29]

The *Water Act* replaced the sixty-year-old *Water Resources Act*[30] on 1 January 1999. The new Act focuses on managing and protecting water on allocation. Some of the major changes are beneficial to the oil and gas industry. For example, the new Act exempts saline groundwater used in reservoir flooding from its licensing process. However, licenses are being limited to ten-year terms, which may put industry at risk that a water license is not renewed when required or that the renewal may have new conditions imposed.

Under the *Water Resources Act*, a license granted the right to divert water from a specific source and a specific project or land. If the land or project were sold, then the license would pass. However, under the new Act, one can transfer allocations of water under a license (approved water management plan or cabinet order). When a license is transferred, the director can withhold 10 percent of the water being transferred or put into place a moratorium if it is in the best interest of the public. The new Act is very broad in its scope in that almost any activity that causes water flow to be changed will likely require approval.

Pipeline management will also be directly affected by the new Act, particularly in regard to hydrostatic testing. Companies will not only have to give notification of testing that provides details concerning the date, location, and duration of testing, but also the amount of water that will be used. Further, ss. 46 and 47 of the new Act prohibit transfers of water between major provincial river basins and transfers outside of Canada. Therefore, if a company obtains water for testing purposes in Alberta, it may not discharge the water at a test site in British Columbia.

Offences and penalties within the new Act use a graduated system for levying fines against repeat offenders. Inspectors have significant powers of entry, search, and seizure as well as the power to halt a diversion of water on the basis of a complaint.

d. *Government Organization Act*[31]

(i) *Energy Grant Amendment Regulation*[32]

The *Energy Grant Amendment Regulation* has amended the *Energy Grant Regulation*.[33] The amendment deals with the requirements of form and substance of a grant application. Schedules 2 and 3 are added to the regulation to provide for the granting of rural gas grants and rural electrification grants. The purposes and the eligibility for each form of grant are set out in detail in the schedules.

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29 S.A. 1996, c. W-3.5.
30 R.S.A. 1980, c. W-5.
31 S.A. 1994, c. G-8.5.
32 Alta. Reg. 252/98.
33 Alta. Reg. 309/86.

e. *Mines and Minerals Act*[34]

(i) *Exploration Regulation*[35]

The previous *Exploration Regulation*[36] expired on 1 October 1998 and was replaced by the new *Exploration Regulation.* The new regulation sets out the process involved to obtain approval for exploration. An approval authorizes the licensee to use the land designated in the approval for a specified use. Consent is required for exploration on private land, Crown land, various types of public land, land that is within the boundaries of a city, town, or village, and exploration on Metis settlement lands. The new regulation also sets out a description of the type of exploration that is prohibited. For example, Schedule 1 sets out twenty-four areas that have restricted the type of exploration activities that may take place. Additionally, exploration may not be carried out within the area of an approval for a scheme or operation that has been granted under the *Oil Sands Conservation Act.*[37]

Penalties for contravention of various sections of the *Mines and Mineral Act* are set out in s. 7. Licensing and permit fees are set out in Part 2. For example, the minister may not grant an exploration license or permit unless an applicant submits: an application, an application fee of $50, a deposit of $2500, and proof of registration as a corporation (if applicable). Part 3 discusses exploration approvals. An application for exploration must contain five copies of a preliminary plan[38] and an application fee of $350.

In certain situations, notice must be given to the Public Land Management Branch of the Rural Development Division of the Department of Agriculture, Food and Rural Development of the commencement date of field operations, the location of the field headquarters, and the date of completion of an exploration program. Several other sections specify situations where notice must also be given to other parties such as the district supervisor, the senior forest officer, and municipal districts and counties. The powers of an inspector and the requirements for displaying the permit number are discussed in detail. Furthermore, procedures are put in place that describe the requirements of a licensee when there is a release of water or gas or there is a subsidence of land surrounding a hole. A licensee or permittee also has duties to ensure that cut lines on public lands are no more than eight metres wide unless consent has been granted. Furthermore, procedures have been put in place that require care in the salvage and clearing of timber and vegetation.[39]

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34 R.S.A. 1980, c. M-15.

35 Alta. Reg. 214/98.

36 Alta. Reg. 32/90.

37 S.A. 1983, c. O-5.5.

38 The requirements for a preliminary plan are set out in s. 10. These requirements include, *inter alia*, a map of the location of the area to be explored according to the specifications set out.

39 The new *Exploration Regulation* will expire on 1 October 2003.

(ii) *Miscellaneous Correction and Repeal Regulation*[40]

The *Miscellaneous Correction and Repeal Regulation* repealed the *Exploratory Drilling Incentive Regulation 1984*.[41]

(iii) *Reactivated Well Royalty Exemption Amendment Regulation*[42]

Subsection 2(4) of the *Reactivated Well Royalty Exemption Regulation*[43] was amended by the *Reactivated Well Royalty Exemption Amendment Regulation.* This had the effect of changing the wording from "a qualifying period must begin on a month after the month of the earliest finished drilling date of the well" to "a qualifying period begins on the first day of a month after the month of the earliest finished drilling date of the well."

(iv) *Natural Gas Royalty Regulation, 1994 Amendment Regulation*[44]

The *Natural Gas Royalty Regulation, 1994*[45] was amended by the *Natural Gas Royalty Regulation, 1994 Amendment Regulation.* Significant changes were made in the administrative procedures for reporting under the regulation. Specifically, any report, statement, or other document required to be furnished must contain all the information required by the prescribed form in accordance with any general directions given by the minister. The minister has authority to refuse to accept any report, statement, or other document that does not meet these requirements, the effect of which is that the document is considered to have never been submitted.

Section 17 ("allowable costs") was amended so that a royalty client may reallocate all or part of the allowable capital costs allocated to it to another royalty client. Where this occurs, a royalty client must provide a report to the minister respecting the reallocation on or before May 15 following the year to which the reallocation related. Finally, the penalty section was amended to change the penalties in cases where an individual has failed to make a report to the minister.

f. *Natural Gas Marketing Act*[46]

(i) *Natural Gas Marketing Amendment Regulation*[47]

The *Natural Gas Marketing Regulation*[48] has been amended by the *Natural Gas Marketing Amendment Regulation* by repealing ss. 20(6) and 23(8). This has the effect

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40 Alta. Reg. 131/98.
41 Alta. Reg. 137/84.
42 Alta. Reg. 184/98.
43 Alta. Reg. 352/92.
44 Alta. Reg. 42/99.
45 Alta. Reg. 351/93.
46 S.A. 1986, c. N-2.8.
47 Alta. Reg. 185/98.
48 Alta. Reg. 358/86.

of allowing the commission, in certain circumstances, to grant a penalty waiver resulting from a failure to furnish various monthly reports or statements required by a direction, under ss. 19 and 23 respectively.

g. *Oil and Gas Conservation Act*[49]

(i) *Oil and Gas Conservation Amendment Regulations*[50]

The *Oil and Gas Conservation Regulations* were amended several times during the last year,[51] the most significant of which amendments related to oil sands development:[52] The definition of "oil sands strata" was added to the regulations. Further, new sections were added to require that no person can produce gas from a well completed in the oil sands strata without approval to commence, suspend, or abandon an oil sands site, an experimental scheme, an *in situ* operation, a mining operation, or a processing plant under the *Oil Sands Conservation Regulation.*[53] Any well that is drilled in the oil sands strata must be drilled deep enough to be able to log over the base of the oil sands deposit unless an exemption has been obtained from the Alberta Energy and Utilities Board ("EUB").

Subsections 3.020(2) and (3) were repealed and replaced with new ss. 12.020 and 12.030 that set out the reporting requirements following the testing of a well or a well that produced petroleum substances during the preceding month.[54] The abandonment

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49 R.S.A. 1980, c. O-5.

50 Alta. Reg. 151/71.

51 Alta. Reg. 78/98; Alta. Reg. 128/98; Alta. Reg. 143/98; Alta. Reg. 179/98; Alta. Reg. 224/98; Alta. Reg. 229/98; Alta. Reg. 47/99.

52 Alta. Reg. 47/99.

53 Alta. Reg. 76/88.

54 Alta. Reg. 78/98. Following the testing or production of a well, the licensee must file, no later than the 18th day of the month (or the first business day following the 18th day), a report of the test and actual production obtained during the preceding month. The report must include the amounts of crude oil, condensate, crude bitumen, gas, water, or other substances produced from the well and the number of hours that the well produced. The licensee of a new oil or gas well must also notify the board of the date the oil or well first produced, was placed on regular production, was placed on injection, or was used for disposal, within fourteen days of the event occurring. The licensee of a well that has produced, been injected, or disposal operations are shut in, may suspend a well by notifying the board of the date of the suspension. A licensee of a well where production, injection, or disposal has resumed or been abandoned, or where commingling of two or more zones has occurred, must notify the board within fourteen days of the respective event. A licensee of a shut-in well during the preceding month must report to the board, no later than the 18th day of the month, the unique well identifier and continue to do so until operations have been resumed or the well has been suspended or abandoned. Finally, an operator of a battery, injection, or disposal facility, where all the wells have been shut in, suspended, or abandoned, or where no wells were associated with the battery during the preceding month, must file, no later than the 18th day of the month, a report that sets out the particulars of any receipts, inventories, dispositions, or deliveries of substances associated with production, injection, or disposal. This reporting must continue until there are no such receipts, inventories, dispositions, or deliveries.
All of the reports made under this amendment must be made on the approved formatted media as set out in A.E.U.B., Guide 59, *Well Drilling and Completion Data Filing Requirements* (October 1998) [hereinafter *Guide 59*].

fund levy for the 1998/1999 fiscal year was established as $100 for each inactive well[55] in each class.[56] Section 16.081 of the regulations was repealed and substituted with a section in Part 16 ("Levies on Wells and Oil Sands Projects") that provides the annual adjustment factor of 0.996 shall be applied to the administration fees for the 1998/1999 fiscal year for individual wells.[57] Further, an annual adjustment factor of 2.25 shall be applied to the administration fees for various classes of oil sands projects.

The balance of the amendments related to clarifying fees and fee administration,[58] qualification and wellsite availability of a licensee wellsite representative and a rig manager (tool push),[59] and amending the definition of "finished drilling date" to "the date at which the total depth of a well is reached."[60] In addition, schedule 3 ("Submission Requirements for Daily Record of Operations") was repealed and s. 12.010 was amended to state that the licensee of a well (or its representative) shall keep and file with the board, records or reports relating to the operations of a well in accordance with *Guide 59*.[61]

h. *Oil Sands Conservation Act*

(i) *Oil Sands Conservation Amendment Regulation*[62]

The *Oil Sands Conservation Regulation* was amended by the *Oil Sands Conservation Amendment Regulation* by repealing ss. 43 and 44 and substituting new sections that set out the resuming requirements following a well being placed on production, resuming production, commingled production, abandonment, injection, a change in status or when the well is first used for disposal.[63] The monthly report filing requirements are also set out in the new amendments. A license holder of a well that produced, was shut in, suspended, abandoned, or subject to injection must file, no later than the 18th day of the month (or first business day thereafter), a report according to the criteria set out by the regulation.

(ii) *Oil Sands Conservation Amendment Regulation*[64]

The *Oil Sands Conservation Regulation* was amended by the *Oil Sands Conservation Amendment Regulation* by adding the definitions of "oil sands strata" and "solution

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55 An "inactive well" means a well at which normal producing or injecting operations had ceased as at December 31 of the calendar year preceding the base year and were not continuously resumed during the base year.
56 Alta. Reg. 128/98.
57 Alta. Reg. 143/98. For the purpose of part 11 of the Act, the prescribed date for the 1998/1999 fiscal year of the board is 31 March 1999.
58 Alta. Reg. 179/98.
59 Alta. Reg. 224/98.
60 Alta. Reg. 229/98.
61 *Guide 59*, *supra* note 54.
62 Alta. Reg. 79/98.
63 The Board must be notified within fourteen days.
64 Alta. Reg. 48/99.

gas." The new regulation requires that no person can produce gas[65] from a well completed in the oil sands strata prior to obtaining approval from the EUB. The EUB may also make any order it considers necessary to conserve the crude bitumen in the oil sands strata.

i. *Pipeline Act*[66]

(i) *Pipeline Amendment Regulations*

The *Pipeline Regulation*[67] was amended twice during 1998.[68] Several miscellaneous sections of the regulation were changed. The definition for "HVP liquid" was amended, and the codes and standards contained within s. 6 were amended. Several sections were added to require a permittee or licensee to patrol its pipeline right of way and conduct inspections and conduct material balance inspections in accordance with the new sections. Section 15 of the *Pipeline Regulation*, which required thermoplastic pipe joints to have CSA certification, was repealed. Subsection 23(5.1) was added to allow a licensee or permittee to erect a pipeline warning sign for a group of pipelines in the same way as a single pipeline. Finally, several amendments were made respecting gases used in testing and the retention of records. In addition, ss. 76 to 78 and 82, setting out fees for applications, certified copies, and variances/waivers, were all repealed.

j. *Water Act*

(i) *Water (Ministerial) Regulation*[69]

The *Water (Ministerial) Regulation* was passed with the introduction of the new *Water Act* pursuant to s. 169(2) and s. 170. The regulation defined "Activities"[70] that are subject to the *Water Act*, diversions and transfers of water,[71] notice requirements, access to information, Land Compensation Board procedures, dam and canal safety, and all facets of the procedures in connection with water wells. The most important impacts to the oil and gas industry can be found in the earlier discussion of the new *Water Act*. Offences and penalties established under the *Water (Offences and Penalties) Regulation*[72] continue to apply.

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65 This does not include solution gas as defined in the regulation.

66 R.S.A. 1980, c. P-8.

67 Alta. Reg. 122/87.

68 Alta. Reg. 85/98; Alta. Reg. 181/98.

69 Alta. Reg. 205/98.

70 Activities that are described in schedule 1 are exempt from the requirement for approval. Schedule 2 also provides exemptions to the requirement of approval in certain areas of the Province.

71 Temporary diversions are subject to the *Code of Practice for the Temporary Diversion of Water for Hydrostatic Testing of Pipelines*, online: Government of Alberta <http://www.gov.ab.ca/qp/ascii/codes/divers.tex> (last modified: October 1999).

72 Alta. Reg. 193/98.

k. *Gas Utilities Act*[73]

(i) *Gas Utilities Exemption Regulation*[74]

The old *Gas Utilities Exemption Regulation*[75] was repealed and superceded by the new *Gas Utilities Exemption Regulation*, which sets out the exemptions from the operation of s. 5 ("Requirements for an Order in Council") of the *Gas Utilities Act*. The new regulation expires on 31 December 2003.

l. *Regulations Act*[76]

(i) *Miscellaneous Correction and Repeal Regulation*[77]

The *Nova Corporation of Alberta Regulation*[78] was repealed by the *Miscellaneous Correction and Repeal Regulation*.

2. SASKATCHEWAN LEGISLATION

a. *Pipelines Act, 1998*[79]

The *Pipelines Act, 1998* replaces the old *Pipe Lines Act*[80] and implements a number of major changes. The new Act simplifies the licensing process for approval to construct, alter, operate, suspend, and abandon pipelines. There is now clarification that the Act includes all oil and gas pipelines and all pipelines transporting any substance used in the production of oil and gas. With the exception of licensing requirements, the Act does not apply to pipelines regulated by the *NEB Act* or to the gas distribution pipelines regulated under the *SaskEnergy Act*.[81] The Act contains clarification that pipeline companies are to use the expropriation procedures under the *Expropriation Procedure Act*.[82] Authorization is provided for the minister to declare a pipeline, other than a pipeline used for the transportation of natural gas, to be a common carrier and to provide non-discriminatory access. Finally, a new requirement is imposed that all persons notify a pipeline company if they are planning any ground disturbance within thirty metres of a pipeline.

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73 R.S.A. 1980, c. G-4.
74 Alta. Reg. 53/99.
75 Alta. Reg. 195/82.
76 R.S.A. 1980, c. R-13.
77 Alta. Reg. 15/99.
78 Alta. Reg. 359/86.
79 Bill 25, *An Act respecting Pipelines*, 3d Sess., 23d Leg., Saskatchewan, 1998 (assented to 11 June 1998, S.S. 1998, c. P-12.1).
80 R.S.S. 1978, c. P-12.
81 S.S. 1992, c. S-35.1.
82 R.S.S. 1978, c. E-16.

b. *Gas Inspection Amendment Act, 1998*[83]

The amendments contained in the *Gas Inspection Amendment Act, 1998* have the effect of removing the term "maintenance" from the definition of "gas installation." The amendment also clarifies that the operator of a gas distribution system is responsible for gas piping, not gas equipment. Thus, an operator must be satisfied, before a connection is made, that the gas piping is free from defects that might cause a hazard to life or property.

Finally, the new Act increases the authority of an inspector to act in hazardous situations where there is danger to property and where the hazard is other than fire.

c. *Oil and Gas Conservation Amendment Act, 1998*[84]

The *Oil and Gas Conservation Amendment Act, 1998*, via operation of the new s. 56.1, authorizes the minister, on application, to suspend and, if necessary, to reinstate the requirement for natural gas producers and users to obtain gas use and gas removal permits with the express purpose of conserving and managing gas resources within the province. It also provides for regulations to be made setting out penalties for late and incomplete submission of drill cores and samples to the Department of Energy and Mines.

d. *The Crown Oil and Gas Royalty Amendment Regulations, 1999*[85]

The *Crown Oil and Gas Royalty Regulations*[86] have been amended by *The Crown Oil and Gas Royalty Amendment Regulations, 1999*. As with the *Freehold Oil and Gas Production Tax Amendment Regulations, 1999*,[87] numerous definitions have been added such as "inter gas well distance," "southwest designated oil," and "qualifying horizontal oil well." The amendments are mainly administrative in nature, but there were also many technical sections amended so as to affect the calculation of royalties. For example, s. 12 has been amended to change the calculation for "southwest designated oil."[88] Further, s. 16 has been amended to set the well-head value of oil produced from or allocated to an oil/gas well. The definition of "gas cost allowance" was amended under s. 42 and the calculation for third tier gas was amended.

Also of note is the amendment to s. 44.2, which gives the minister authority in cases where the operator or special operator sells gas during a month and, through a review or audit, the minister is satisfied that gas that was produced in Saskatchewan was allocated to specific sales contracts and unduly or artificially reduced the royalty payable. In those cases, the minister may specify the sales contracts to which the gas

83 S.S. 1998, c. 22.
84 S.S. 1998, c. 30.
85 Sask. Reg. 2/99.
86 R.R.S. c. S-29, Reg. 9.
87 Sask. Reg. 3/99.
88 Please see the entire text for the lengthy calculation set out under s. 12.

is to be allocated that more accurately reflect the value received for the Saskatchewan gas by the operator or special operator to determine the well-head value of the gas.

e. *The Petroleum and Natural Gas Amendment Regulations, 1998*[89]

The *Petroleum and Natural Gas Regulations, 1969*[90] were amended by *The Petroleum and Natural Gas Amendment Regulations, 1998*. The new regulations amended the definition of "Act" and "adjoin/adjoining." The amendments also stated that the regulations apply to all oil and gas rights that are the property of the Crown in right of Saskatchewan and are disposed of pursuant to the regulations or are deemed to be Crown dispositions. Furthermore, an exploration license is deemed to be a Crown lease within the meaning of the Act to determine royalties that are payable on oil and gas produced.

f. *The Freehold Oil and Gas Production Tax Act*[91]

(i) *The Freehold Oil and Gas Production Tax Amendment Regulations, 1999*

The *Freehold Oil and Gas Production Tax Regulations, 1995*[92] were amended by the *Freehold Oil and Gas Production Tax Amendment Regulations, 1999*, which added numerous definitions and re-defined terms, including "inter-gas well distance," "inter-oil well distance," and "southwest designated oil." The amendments were mainly minor administrative changes. However, there were also many technical sections amended so as to change the calculation required for the production tax. For example, s. 9 was amended to change the calculation for southwest designated oil. Section 13 was amended to set the well-head value of oil produced from or allocated to an oil or gas well. Section 41 was amended to substitute a new definition of "gas cost allowance" and set out a new calculation for third tier gas. Also of note is the amendment to s. 43.2 which allows the minister to specify sales contracts, to which a gas sale is allocated, to more accurately reflect the value received for the Saskatchewan gas by the operator for the purposes of determining the well-head value of the gas. This may occur in situations where the minister believes that the sales contracts unduly or artificially reduced the royalty payable on the gas.

89 Sask. Reg. 49/98.
90 Sask. Reg. 8/69.
91 S.S. 1982-83, c. F-22.1.
92 R.R.S. 1995, c. F-22.1, Reg. 1.

g. *The Oil and Gas Conservation Act*[93]

(i) *Oil and Gas Conservation Amendment Regulations, 1998*[94]

The *Oil and Gas Conservation Regulations, 1985*[95] were amended by the *Oil and Gas Conservation Amendment Regulations, 1998*. The amendments set out changes to the notice and documentation requirements for license holders, the requirements for drilled survey reports and plans, the labelling of submissions, and application fees.

3. BRITISH COLUMBIA LEGISLATION

a. *Oil and Gas Commission Act*[96]

The new *Oil and Gas Commission Act* received royal assent on 30 July 1998. The Act established a corporation to be known as the Oil and Gas Commission (the "Commission"). The primary purposes of the Commission are to regulate oil and gas activities and pipelines in British Columbia (within one regulatory window), to provide processes for the review of applications related to oil and gas activities or pipelines, and to encourage the participation of First Nations in processes that affect them. As the Commission can issue permits, licenses and approvals, and other authorization under the various Acts for oil and gas activities, the "walk around" process has been discontinued. The breadth of authority is quite wide, as the Commission can grant land tenure under the *Land Act*[97] and cutting permits under the *Forest Act*.[98] The Act sets out the administrative powers, duties, and capacity of the Commission and its board. The Commission will encourage the use of consensual alternative dispute resolution in the context of the *Oil and Gas Commission Act*, the *Petroleum and Natural Gas Act*,[99] and the *Pipeline Act*.[100] Among other duties, the Commission will hear applications to declare a person to be a common carrier, a common purchaser, and a common processor. However, the terms of transportation, purchase, and processing will still be dealt with by the British Columbia Utilities Commission. It should be noted that none of the required licenses and approvals have been changed, but merely the regulating authority. Some streamlining of the procedures has been done, but Commission staff have advised that they will be looking for further benefits.[101]

93 R.S.S. 1978, c. O-2.
94 Sask. Reg. 50/98.
95 R.R.S. 1985, c. O-2, Reg. 1.
96 S.B.C. 1998, c. 39.
97 R.S.B.C. 1996, c. 245.
98 R.S.B.C. 1996, c. 157.
99 R.S.B.C. 1996, c. 361.
100 R.S.B.C. 1996, c. 364.
101 See subsection III.C.1.c., below, for the British Columbia Oil and Gas Commission information letters summary.

(i) *Oil and Gas Commission Levy Regulation*[102]

The Commission has put forth the new *Oil and Gas Commission Levy Regulation* to deal with levy rates and levy payments. The intent is that the Commission would be funded entirely by the oil and gas industry through the levy and through fees under the *Petroleum and Natural Gas Act* and the *Pipeline Act*. The regulations set out the calculation for the levy rate for marketable gas and for petroleum. A designated collector must invoice each producer monthly by multiplying the levy rate applicable by the volume of marketable gas/petroleum produced during the preceding production month. If a producer fails to pay an invoice within forty-five days, the license or lease granted to the producer may be suspended or cancelled on notice to the producer.

b. *Petroleum and Natural Gas Act*

(i) *Oil and Gas Commission Act*

The *Petroleum and Natural Gas Act* was amended by the *Oil and Gas Commission Act* primarily to reflect the change in authority thereunder from the minister to the Commission.

(ii) *Petroleum and Natural Gas Freehold Production and Tax Regulation*[103]

The amendment to the *Petroleum and Natural Gas Freehold Production and Tax Regulation* adds to and re-defines the definitions set out in s. 1.[104] Specifically, "completed well," "completion date," "incremental oil," "old oil," "royalty share," "select price," and "third tier oil" are added. More importantly, s. 5 was amended and set out new calculations for royalties of third tier oil and non-conservation gas in items 1, 1.1, 1.2, 4.1, and 4.2.

(iii) *Regulation Repealing Drilling and Exploration Regulations*[105]

This regulation, effective 23 October 1998, repeals the *Drilling and Production Regulation*[106] and the *Geophysical Exploration Regulation.*[107]

(iv) *Petroleum Development Road Regulation*[108]

The old *Petroleum Development Road Regulations*[109] were repealed and substituted by the new *Petroleum Development Road Regulation*. The new regulation sets out the application requirements for a petroleum development road, survey requirements, and

102 B.C. Reg. 363/98.
103 B.C. Reg. 180/98.
104 B.C. Reg. 495/92.
105 B.C. Reg. 351/98.
106 B.C. Reg. 336/91.
107 B.C. Reg. 348/88.
108 B.C. Reg. 356/98.
109 B.C. Reg. 77/69.

the operation of petroleum development roads. An operator of an approved petroleum development road may make bylaws, rules and regulations respecting speed, weights, size of vehicles permitted, and traffic, after approval of the requirements by the commission.

(v) *Petroleum and Natural Gas General Regulation*[110]

The new *Petroleum and Natural Gas General Regulation* sets out fees for applications and examinations and numerous other administrative actions. The new regulation states that, for other than normal spacing of a petroleum well or gas well, an application must be made to the division head from the holder of a location that overlies (or appears to overly) a pool. Further, a drilling deposit must be submitted to the Commission by a well operator or by a person who drills a test hole, as security for the proper drilling or applicable treatment of the well or test hole. The regulation also compels the minister to encourage efforts to consolidate interests that result in more efficient and economical development of the resources of a pool. Provision for improved recovery schemes reporting is also made under the regulation.

(vi) *Geophysical Exploration Regulation*[111]

The *Geophysical Exploration Regulation* has been made and put forth by the Commission. The regulation applies to all geophysical exploration for petroleum and natural gas in British Columbia. It sets out the requirements for an application for project approval, reporting, performance bonds, shot-hole plugging, marking shot-holes, and dealing with unexploded charges. It also addresses a situation where gas or water is released and flows to the surface during or after drilling. In this situation, drilling must be discontinued immediately, an explosive charge must be detonated in the hole, and the hole must be plugged (and a report filed). If the exploration causes damage to land or property, the operator must take immediate steps to prevent further damage and repair existing damage.

(vii) *Drilling and Production Regulation*[112]

The new *Drilling and Production Regulation* has been put forth by order of the new Commission. Part 2 of the regulation generally deals with well positions, spacing, and target areas and sets out the requirements for well classifications and authorizations (including transfers and amendments). For example, under s. 5, a well may not be drilled within eight metres of a right of way, easement, road allowance, public utility, permanent building, public concourse, or reservation for national defence. In addition to limiting the position of wells, the position of test holes and wells near mines are also restricted.

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110 B.C. Reg. 357/98.

111 B.C. Reg. 361/98.

112 B.C. Reg. 362/98.

Part 3 sets out the requirements for well authorizations, well classifications, and transfers of well authorization. Section 16 is a good example of the regulatory authority of the new Commission. It states that a well authorization cannot be transferred without the consent of the Commission. The transfer must be accompanied by an "Application to Change a Well Name" and an "Application to Transfer a Well Authorization." This authorization is entirely in the discretion of the Commission. Section 18 sets out the requirements of a test hole and the procedures to follow to obtain authorization.

Part 4 defines the equipment to be used in well operations and blowout prevention and outlines the notice that must be provided to the Commission (within twenty-four hours of the commencement of the drilling of a well). Further, the requirements for testing and servicing of blowout prevention equipment is set out. Division 5 of Part 4 sets out the procedures to be followed where there is an uncontrolled flow, provision for fluid containment, and sealing off oil, gas, or water. Under s. 40, a well must not be drilled beyond any oil, gas, or water stratum until the applicable substance is controlled by drilling fluid, casing, or cement, unless the Commission has approved otherwise.

Part 5 discusses well abandonment and the plugging requirements for wells and test holes. The most important feature is that an "Application to Abandon a Well" must be provided to the Commission before abandoning a well or a test hole and approval must be given by the Commission.

Part 6 deals with well data and the submission of information, daily reports, and samples and cores. For example, a daily report must be kept at the site of a well drilled with legible copies of the reports (for each calendar week) to be submitted to the Commission and copies retained by the operator.[113] Section 52 directs that a series of samples must be taken at five-metre intervals of the various formations, then washed, dried, and preserved in bags tied in groups of ten consecutive samples. The samples must be forwarded to the Commission, carriage prepaid, as soon as possible after the total depth is reached and not later than fourteen days after rig release.

Part 7 deals with the prevention of damage, fires, injuries, and losses. Part 8 deals with oil, gas, and water production operations. The daily oil and gas production allowable is set out, as is the metering and measurement of gas and oil, and the overproduction of oil and gas.

Subsequent to the introduction of the regulation, it was amended on 10 November 1998,[114] to add schedules to determine the emergency planning zone radius, the gas-oil adjustment factor calculation, the minimum unadjusted oil allowables, and the prescribed warning signs.

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113 The contents of the daily reports are extensive and are set out in s. 50(3) of the regulation.

114 B.C. Reg. 393/98.

c. *Pipeline Act*

(i) *The Oil and Gas Commission Act*

The *Pipeline Act* has been amended by Bill 32, the *Oil and Gas Commission Act.* As with other consequential amendments, most of the amendments give authority to the commission where the minister formerly had authority. Section 2 was also amended so that a company must not operate a pipeline in British Columbia without the consent in writing of the commission, subject to any conditions that it may impose.

(ii) *Sour Pipeline Regulation*[115]

The former *Sour Pipeline Regulation*[116] is repealed and replaced by the new *Sour Pipeline Regulation.* The new regulation sets out the minimum setback for a sour pipeline that is built after the regulation comes into force. It also states that an emergency planning zone and an emergency response plan must be maintained for each sour pipeline that has the approval of the chief inspecting engineer.[117] The regulation also calls for additional design requirements for sour pipelines, including check and block valves, emergency shut-down devices, and H_2S signs.

(iii) *Pipeline Regulation*[118]

The old *Pipeline Regulation*[119] was repealed and replaced, effective 23 October 1998, by the new *Pipeline Regulation* which applies to all pipelines in British Columbia constructed or operating within the jurisdiction. The new regulation generally addresses procedures that are required for the application and receipt of leave to construct a pipeline and reporting requirements. Section 22 provides that a company must notify the Commission where there has been spillage of oil or gas or solids, malfunction or damage to the pipeline, or incidents likely to cause or contribute to spillage, in the form directed by the chief inspecting engineer.

d. *Utilities Commission Act*[120]

(i) *The Oil and Gas Commission Act*

The *Utilities Commission Act* has been amended by the *Oil and Gas Commission Act.* Sections 65 to 67 respecting carriers, purchasers, and processors were amended to enable both the Commission and the British Columbia Utilities Commission to establish the conditions under which a common carrier, purchaser, or processor deals with petroleum substances.

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115 B.C. Reg. 359/98.

116 B.C. Reg. 448/92.

117 The extensive requirements for the emergency planning zone and the emergency response plan are set out in detail in the regulation.

118 B.C. Reg. 360/98.

119 B.C. Reg. 451/59.

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

e. *Environmental Assessment Act*[121]

(i) *Environmental Assessment Reviewable Projects Amendment Regulation*[122]

The *Environmental Assessment Reviewable Projects Amendment Regulation* has amended the *Environmental Assessment Reviewable Projects Regulation.*[123] Section 28.1 was repealed and substituted with a new section that governs construction of new and existing natural gas processing plants. For the purposes of the Act, the construction of a new facility will constitute a reviewable project. Further, the modification of an existing facility constitutes a reviewable project if there is a substantial increase in sulphur emissions or a substantial change in the capacity of the plant to process natural gas.

4. NOVA SCOTIA LEGISLATION

a. *Gas Distribution Act (amended)*[124]

Clause 1 of Bill 39 provides that the Nova Scotia Utility and Review Board shall not grant a franchise pursuant to the Act until it is satisfied that the applicant has committed to supplying gas to all parts of the franchise area. Clause 2 gives a municipality or co-operative the right to appear at a hearing, provides for its funding, and waives the application fee.

(i) *Gas Distribution Regulations (Nova Scotia)*[125]

The new *Gas Distribution Regulations (Nova Scotia)* give the Nova Scotia Utility and Review Board (the "Board") the authority to grant franchises within the province to a company to construct and operate a gas delivery system. It also sets out particular requirements for a franchise application, its terms and conditions, and the requirements that are exempted from certain classes of applicants. The regulations set out the performance-based rates, tolls, or charges that are to be determined by the Board in awarding a franchise. Reference is also made to the procedures required to amend and renew franchises. The unique powers and duties of the Board include inquiry and investigation, rule-making, consultation with other public bodies, retention of experts, compelling witness attendance, and document production. The attached schedules to the regulations set out distribution targets for each county and also put forth a policy statement on maximizing benefits from natural gas delivery.

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121 R.S.B.C. 1996, c. 119.
122 B.C. Reg. 399/98.
123 B.C. Reg. 276/95.
124 Bill 39, *An Act to Amend Chapter 4 of the Acts of 1997, the Gas Distribution Act, to Ensure Distribution of Natural Gas Throughout Nova Scotia and to Make Municipalities Full Participants in Gas Distribution*, 1st Sess., 57th Gen. Ass., Nova Scotia, 1998 (1st reading 22 October 1998).
125 N.S. Reg. 86/98.

It should also be noted that some subsequent minor administrative changes were made to these regulations.[126]

(ii) *Board Gas Distribution Regulations (Nova Scotia)*[127]

The *Board Gas Distribution Regulations (Nova Scotia)* have been made pursuant to s. 41(1) of the *Gas Distribution Act*.[128] Part I of the regulations define, for the purposes of s. 23 of the *Gas Distribution Act*, "consumer" to mean a person who consumes less than 500 gigajoules per year.[129] The regulations under Part II set up the application procedures and requirements to receive a grant of a franchise under the Act. Notably, an application requires the proposed term of the franchise (which is not greater than twenty-five years), evidence of the existence of markets, availability of an adequate gas supply, financial capability of the applicant, plans to provide delivery in the franchise area over a potential ten-year term, and a "Socio-Economic Impact Statement."[130] Applications for franchises must be accompanied by $250,000 and $5,000 for any assignment, transfer, or amendment.[131]

b. *Pipeline Act*[132]

(i) *Land Acquisition Regulations*[133]

The new *Land Acquisition Regulations* made under s. 34 of the *Pipeline Act* set out the requirements of an agreement reached with an owner for the purposes of a pipeline. Where a permit or license holder requires land for the purposes of a pipeline and cannot reach an agreement with an owner, application may be made to the minister for a vesting order.[134]

(ii) *Pipeline Regulations (Nova Scotia)*[135]

The new *Pipeline Regulations (Nova Scotia)* apply in respect of pipelines designed, constructed, operated, maintained, or abandoned on Nova Scotia lands after 16 September 1998. The new regulations set out an exhaustive list of definitions and require a permit or license issued by the Energy and Mineral Resources Conservation Board ("Energy Board") for the applicable pipeline. Except where required by the

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126 N.S. Reg. 31/99.

127 N.S. Reg. 93/98.

128 S.N.S. 1997, c. 4.

129 Under s. 24 of the *Gas Distribution Act*, no person is able to sell gas to a "consumer" unless a license has been issued by the board.

130 All of the requirements under Part II applications also apply to an assignment, transfer, or amendment of a franchise.

131 This fee may be waived if the board believes the application for assignment, transfer, or amendment is routine in nature.

132 R.S.N.S. 1989, c. 345.

133 N.S. Reg. 67/98.

134 The requirements of a vesting order are set out in s. 6 of the regulation (for known owners) and s. 7 (for unknown owners).

135 N.S. Reg. 66/98.

Pipeline Act, the *Utility and Review Board Act*[136] and their respective regulations, and procedures are subject to the determination of the Energy Board. The regulations set out the power of the Energy Board to require a corporation to test and inspect a pipeline. Fees and standards for operations, materials, and designs of a pipeline are set out in ss. 7 to 9. Requirements and procedures for designs and design approval for liquids pipelines, stations, and storage of petroleum are set out in Part II. The remainder of the regulations deal with materials specifications, quality assurance and environmental management, the "Field Joining Program," construction and construction safety, field testing, operation and maintenance, suspension, removal, discontinuance, abandonment, reporting, audits, records, and protection of pipelines.

III. REGULATORY DEVELOPMENTS

A. FEDERAL

1. NATIONAL ENERGY BOARD

a. Decisions

(i) *GH-5-98: Vector Pipeline Limited Partnership — Facilities*[137]

The National Energy Board ("NEB") issued this decision on 31 March 1999, approving the construction and operation of a natural gas pipeline in southwestern Ontario, which represents the Canadian portion (approximately twenty-four kilometres) of a new international 552-kilometre pipeline project providing service between the large market hub located at Joliet near Chicago, Illinois, and the existing hub located at Dawn, Ontario.

The Walpole Island First Nation had raised concerns regarding potential environmental impact of the project on Walpole Island and the St. Clair River. The Gas Pipeline Landowners Association of Ontario had expressed concerns regarding tile drains, soil compaction, and crop loss. However, Vector Pipeline Limited Partnership ("Vector") reached agreement with both parties before the hearing opened and both withdrew from further participation. Also, the Canadian Association of Petroleum Producers ("CAPP") had requested an adjournment prior to the hearing, but withdrew its motion after Vector indicated that a separate toll application would be filed with the NEB for the stub-year service if Vector determined that such a service was warranted.

Although environmental comments and issues were raised by a number of interveners, the NEB indicated satisfaction with the potential environmental impacts subject to the proposed mitigation measures and conditions imposed. The NEB accepted that sufficient gas supply from diversified sources in Western Canada, the Gulf Coast, the mid-continent, and the Rocky Mountain producing areas would likely be available

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136 S.N.S. 1992, c. 11.

137 *Re Vector Pipeline Limited Partnership Application dated 6 July 1998 for the Vector Pipeline Project* (March 1999), GH-5-98 (N.E.B.).

to allow the proposed facilities to maintain viable utilization rates. The NEB noted that, although the proposed system might not be fully utilized in the short term, forecast growth in demand would be sufficient to support the facilities over the life of the project and that Vector and its shippers would take the financial risk of any unutilized capacity. The NEB also included a condition directing Vector not to place the applied-for facilities into service before 1 October 2000, as requested by CAPP and agreed to by Vector. The existence of signed long-term transportation agreements was strong evidence in favour of the pipeline, however, Vector was to submit copies of executed transportation agreements prior to construction.

The NEB approved the proposed negotiated toll settlement which calculates tolls on a postage stamp basis for all movements within the subject section of pipeline. The toll settlement incorporates four incentive mechanisms and contains key provisions based on a fifteen-year-term transportation agreement. Tolls for gas shipped under agreements with terms of less than fifteen years would be 15 percent above the rate applicable to fifteen-year agreements. In response to a suggestion by TransCanada PipeLines Limited ("TransCanada") that the NEB find that term-differentiated tolls do not violate s. 62 of the *NEB Act*,[138] the NEB considered that the term is a factor in determining whether the associated difference in tolls reflects different circumstances and conditions pursuant to s. 62. However, it approved the settlement as filed. The NEB also rejected TransCanada's suggestion that the time had come for the NEB to reconsider the distinction between "Group 1" and "Group 2" companies for reporting purposes. It then designated Vector as a Group 2 company.

The NEB found that the benefits of the Vector project would likely outweigh the costs, and therefore, the project was in the public interest. The NEB came to this finding in spite of concerns raised by TransCanada regarding the potential risk of harm to all pipelines and shippers in that market by adding capacity and creating an unlevel playing field between incumbent pipelines and new market entrants. The NEB noted that risk is an essential element of competition, and incumbents generally have a competitive advantage in offering expanded capacity because they are able to expand in smaller increments than a greenfield pipeline and can normally "roll in" tolls. The NEB found no evidence of the certainty or magnitude of potential harm and was not persuaded that it would be significant.

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138 *Supra* note 6.

(ii) *RH-2-98: BC Gas Utility Ltd. — Access and Tolls*[139]

In a decision issued 26 March 1999, the NEB approved the request of BC Gas Utility Ltd. ("BC Gas") for a receipt point on the Westcoast Energy Inc. ("Westcoast") natural gas pipeline at Kingsvale, British Columbia. Westcoast stated it did not believe BC Gas would have the ability to deliver gas at Kingsvale; an integral part of BC Gas' ability to deliver was its proposed Southern Crossing Pipeline ("SCP") from Yahk, British Columbia, to Oliver, British Columbia. The SCP application had been turned down by the British Columbia Utilities Commission ("BCUC") in May of 1997. However, the BCUC noted that, after obtaining commitments from British Columbia Hydro and Power Authority, it may wish to apply again, which BC Gas did.[140]

BC Gas had argued that the focus should not be on the SCP as that matter was within the domain of the BCUC. Furthermore, it argued that Westcoast was seeking to erect barriers to entry. Westcoast argued that it was not appropriate nor in the public interest to require it to provide firm capacity as that would cause facilities upstream of Kingsvale to be stranded to the detriment of Westcoast and its shippers. Westcoast also argued that the SCP will be heavily subsidized and BC Gas would thus be imposing the risks of the SCP on Westcoast and its customers; that the proposed tolling scheme on the SCP was anti-competitive and would subsidize Alberta gas at the expense of British Columbia gas; and that the point-to-point toll requested by BC Gas for Westcoast service would further subsidize the SCP. Other interveners appeared on both sides in this hearing.

The NEB characterized the service sought as most closely resembling a new and competing pipeline requesting an interconnection with an existing pipeline. The NEB determined that the case against providing access was mainly related to arguments as to whether the SCP project was in the public interest and that that was not a matter directly relevant to the NEB. They noted that even without the SCP, BC Gas could find ways to deliver volumes of gas to the Westcoast system at Kingsvale. Given that access could allow more choices to the market, there were no facts before the NEB which would lead it to deny access.

The NEB denied BC Gas' request for a point-to-point toll as it would not reflect the cost of providing this service, but it also denied Westcoast's proposal and fixed a toll equivalent to the "zone 4" toll to Huntingdon. With respect to toll methodology for interruptible service from Kingsvale to Huntingdon, with or without the SCP, the NEB decided on the use of a delivery area differential methodology.

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139 *Re BC Gas Utility Ltd. Application dated 14 July 1998 for orders under sections 70 and 71 of the National Energy Board Act requiring Westcoast Energy Inc. to receive, transport and deliver gas from Kingsvale to Huntingdon, British Columbia, and prescribing terms and conditions, including tolls, for the service* (March 1999), RH-2-98 (N.E.B.).

140 See also the discussion of this issue in subsection III.C.1.a.(i), below.

(iii) *GH-4-98: Maritimes & Northeast Pipeline Management Ltd. — Facilities (Point Tupper Lateral)*[141]

In January 1999, the NEB released its decision approving the construction and operation of a lateral natural gas pipeline from the Maritimes & Northeast Pipeline Management Ltd. ("M&NP") mainline near Goldboro, Nova Scotia, to a delivery point at the Sable Offshore Energy Inc. ("SOEI") fractionation plant in the Point Tupper area and to two other customer-specific delivery points. In spite of the fact that some interveners took issue with the size of the lateral and indicated that the design was inadequate to support the foreseeable market, the NEB was not convinced that a larger pipeline was required. Furthermore, given the nature and amount of firm commitments M&NP had obtained, the NEB found it was appropriate for M&NP to design the pipeline to meet its forecast of average daily end-use requirements, rather than to meet speculative peak day forecasts as had been urged by interveners.

M&NP argued that the approach to environmental assessment should be to build on previous environmental assessments by the Joint Public Review Panel for the Sable gas projects[142] for the corridor and the Strait of Canso crossing, and, since the NEB was not approving the construction of the Strait of Canso crossing (as M&NP was planning to purchase the line), the focus of the NEB's environmental screening process should be on the operation of the crossing. The NEB decided that the proposal to construct the pipeline was a project that required an environmental screening under the *Canadian Environmental Assessment Act*, involving a thorough assessment of the environmental effects of all of the components of the Point Tupper facilities, including the Strait of Canso crossing. However, the NEB did rely, to the extent possible, on previously available environmental information including *The Joint Public Review Panel Report*. The NEB found that the work proposed was not likely to cause significant adverse environmental effects, taking into account the implementation of the proposed mitigative measures and the requirements of the attached conditions (which include crossing plans, detailed monitoring programs, and methods to deal with specific problems).

The NEB was generally satisfied regarding socio-economic matters, in spite of an assertion by the Cape Breton Regional Municipality and the Antigonish Regional Development Authority that the application inadequately identified the socio-economic effects of the project. In the NEB's view, that allegation was based on an alleged inadequacy of information bearing on direct socio-economic changes, rather than on environmentally induced socio-economic impacts. The NEB found that M&NP had addressed and assessed the impacts adequately and was also satisfied regarding M&NP's plans to provide full and fair local access to local employment and procurement opportunities. Given M&NP's planning and mitigative measures, adverse community service impacts were unlikely.

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141 *Re Maritimes & Northeast Pipeline Management Ltd. Point Tupper Lateral Facilities Application, as amended, dated 14 August 1998* (January 1999), GH-4-98 (N.E.B.).

142 C.E.A.A. *et al.*, *The Joint Public Review Panel Report* (October 1997).

Concerns were expressed regarding the potential of the proposed project to displace the demand for Cape Breton coal and electricity and to reduce the comparative competitiveness of industrial Cape Breton. However, the NEB found there was no evidence that the project would in and of itself displace the use of Cape Breton coal; the only shippers who had contracted for gas service did not currently use coal, and it was purely speculative that other potential natural gas users would displace coal. Furthermore, assuming that natural gas distribution develops in Nova Scotia as planned, Cape Breton should not be disadvantaged *vis-à-vis* other regions of the Maritimes. The NEB also noted that local access to natural gas could eventually be a major economic benefit.

Several landowners raised issues regarding SOEI's easement agreements and the fact that the natural gas liquid pipeline and the Point Tupper lateral pipeline were regulated separately by provincial and federal regulators. However, the NEB was generally satisfied with M&NP's route selection process and approach to land matters. The NEB found that, for both environmental and economic reasons, it was preferable that there be only one construction event through a sensitive wetland area of the route. M&NP had applied for the area to be removed from the s. 52 application and to be exempted under s. 58 to expedite approval to accommodate SOEI's plans for February 1999 construction through the wetlands. While the NEB ruled that there was no legal basis upon which the motion could be granted, pursuant to the Pesh Creek decision,[143] it did grant M&NP an exemption from the s. 33 requirement that a company file a plan, profile, and book of reference for the pipeline before commencing construction in respect of the wetland area.

In previous proceedings,[144] the NEB approved a postage stamp toll design for the Canadian portion of the M&NP line as it struck an appropriate balance between encouraging the development of gas markets and the ability of M&NP to remain competitive with other alternatives. It had also approved M&NP's "Lateral Policy" which allows for the waiver of any contribution-in-aid of construction resulting from the application of the policy in certain circumstances. Given the long-term commitment of three shippers on this pipeline, the NEB found that the Lateral Policy was correctly applied and the full cost of service should be included in the calculation of M&NP's tolls. While the test toll component of the policy was challenged by SaskEnergy International Incorporated ("SaskEnergy"), the NEB affirmed that it was an integral component of the policy and rejected ITS suggestion. SaskEnergy also criticized "unfettered cherry picking" by M&NP of the industrial load, the impact of which would be to reduce the number of customers and communities that receive natural gas, and requested a policy statement relating to the impact of M&NP's Lateral Policy on local distribution companies, a suggestion the NEB rejected as inappropriate.

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143 *Alberta* v. *Westcoast Energy*, [1997] F.C.J. No. 77 (T.D.), online: QL (FCJ) (as cited by the board).

144 *Re The Sable Offshore Energy Project Application dated 11 June 1996, as amended, for Facilities & Tolls and The Maritime & Northeast Pipeline Project Application dated 7 October 1996, as amended, for Facilities & Tolls* (December 1997), GH-6-96 (N.E.B.).

The Strait of Canso crossing caused some controversy in the proceeding. In November of 1998, M&NP attempted to amend its application to remove the Strait of Canso crossing from the project description; however, the NEB did not allow it to do so, and M&NP withdrew its request. Although M&NP was purchasing the crossing instead of contracting with SOEI to construct it, it still required a certificate from the NEB to operate it. The NEB found the arrangements acceptable, although it would have preferred that M&NP had applied to the NEB to construct and operate the entire fifty-five kilometres of pipeline including the strait.

While all interveners expressed support for the project, their views were varied on the potential size of the market to be served. Although the NEB had significant concerns with the market parts of M&NP's forecast, the fact that the overall load factor would be low in the first few years, and the economic feasibility of the project (which is marginal when compared to a strict application of the economic feasibility test developed in the GH-5-89 decision[145]), the NEB was satisfied that the Point Tupper lateral was and would be required by present and future public convenience and necessity. Referring to it in its decision in Alliance,[146] the NEB noted that firm service agreements were in place for twenty years, demonstrating strong commitment to long-term utilization.

(iv) *GH-3-97: Alliance Pipeline Ltd. on behalf of the Alliance Pipeline Limited Partnership — Facilities and Tolls & Tariffs*[147]

After holding seventy-seven days of public hearings in Calgary, Regina, Fort St. John, and Edmonton, and reviewing the results of a comprehensive study report[148] under the *Canadian Environmental Assessment Act*, the NEB approved an application by Alliance Pipeline Ltd. ("Alliance") to construct and operate the Canadian portion of a high-pressure natural gas pipeline system from northeastern British Columbia and northwestern Alberta to the midwestern United States, although it imposed a number of conditions to ensure protection of property and the environment, the safety of the public, and other interests. In this decision, released in November of 1998, the NEB also approved the tolling arrangements negotiated between Alliance and its shippers. The project involved 1,565 kilometres of mainline and related facilities from a point near Gordondale, Alberta, to a point on the Canada-United States border near Elmore, Saskatchewan, and approximately 770 kilometres of lateral pipelines and related facilities in British Columbia and Alberta. It was estimated to cost approximately $2 billion for the Canadian-based facilities.

145 *Re Reasons for Decision in the Matter of an Application from TransCanada PipeLines Limited for 1991 and 1992 Facilities and Associated Part VI and Section 71 Applications*, vol. 1 (November 1990), GH-5-89 (N.E.B.).

146 *Infra*, note 147.

147 *Re Alliance Pipeline Ltd. on behalf of the Alliance Pipeline Limited Partnership, Alliance Pipeline Project Application dated 3 July 1997* (November 1998), GH-3-97 (N.E.B.).

148 N.E.B., *Comprehensive Study Report In the Matter of Alliance pipeline [sic] Ltd. on behalf of the Alliance Pipeline Limited Partnership application dated 3 July 1997* (September 1998).

Partway through the hearings, an agreement was signed by CAPP and several other interested parties which led them to withdraw substantial portions of evidence they had filed in opposition to Alliance.

The comprehensive study report under the *Canadian Environmental Assessment Act* concluded that the project would not likely cause significant adverse environmental effects provided that the mitigative measures and undertakings committed to during the hearing were implemented together with the forty-one recommendations in the report.

In assessing the economic feasibility of the project, the NEB found that Alliance made a credible case that long-term overall supply would be sufficient to sustain utilization rates, that natural gas markets would be sufficient to support the pipeline, that contractual commitments by shippers were adequate, and that the ability of Alliance and its partners to finance and structure the project was adequate.

In assessing the potential for commercial impact, the NEB found that the Alliance project was well-conceived and provided an innovative alternative to the existing gas transportation infrastructure and that the long-term competitive benefits of the project would be significant and extensive. Initially, however, much strenuous opposition to the project was raised on a number of grounds. Arguments focused mainly on the potential for off-loading and stranded capacity, on the fact that the project would result in duplication and under-utilization and have a negative impact on other utilities, which could cause other customers to pay more for their gas. Concerns were also raised in regard to the requirement for shippers to relinquish the rights to liquids contained in the gas streams delivered to Alliance, the proposed volumetric tolling methodology, the authorized over-run service whereby firm service shippers could utilize spare capacity for the cost of fuel only, and the physical access to liquids on the Alliance pipeline.

The NEB accepted that there may be some temporary under-utilization, however it was not persuaded that there were significant public interest reasons to justify the regulatory actions urged by some parties. The NEB also noted that the potential for duplication of facilities was inherent in the nature of competition and beneficial competition could be in the public interest. In considering arguments presented by parties regarding the negative impacts on the Alberta petrochemical industry as a result of Alliance's proposed tariff, the NEB did not find any features of Alliance's proposed service package to be contrary to the public interest, and found that there would be an adequate ethane supply for both the currently planned and future expansions of the Alberta petrochemical industry. It also did not agree that physical access to the liquids carried on the pipeline would be a significant issue once the pipeline was in operation. The NEB was not persuaded to adopt any of the specific proposals argued by parties aimed at enhancing domestic access to natural gas, and suggested that potential gas buyers should attempt to negotiate commercial arrangements with gas suppliers and gas transportation companies under market conditions.

In chapter 4 of its decision, the NEB considered socio-economic and land matters, and, although generally satisfied, ordered Alliance to report on its performance in respect of First Nations and Metis employment and commercial participation objectives on a quarterly basis during construction and annually during the first three years of operation. However, the NEB found that Alliance's proposed land requirements were reasonable and justified, and was generally satisfied with the location of the Alliance pipeline. The NEB was not persuaded by arguments that the number of crossings in the system should override the other criteria used by Alliance in selecting the general location. However, Alliance's request for construction within an 800-metre corridor to accommodate future route refinements was denied.

Several landowners expressed concern regarding safety, abandonment, routing of the pipeline, loss of vegetation and wildlife habitat, impacts on use and enjoyment of the land, possible effects of heat from the pipeline on crops, and the visibility of compressor stations. Any certificate issued would be conditioned to require NEB approval of any re-routes to address concerns for wildlife or rare or unique plant species.

The NEB felt that Alliance should be given an opportunity to attempt to reach agreement with owners of utilities which it may cross, and accordingly waived the requirement for Alliance to obtain leave to cross other utilities, aside from navigable waterways and railways. Fracture initiation tolerance, a measure of a pipe wall's resistence to penetration by a crack or flaw, and fracture propagation resistance, the distance at which a fracture will arrest, were central considerations in assessing safety and operational integrity. The company had to demonstrate that the fracture design of its pipeline satisfied the intent of the CSA Z662 standard and achieved the required degree of safety and integrity. The NEB was satisfied with Alliance's fracture initiation control design but required Alliance to file a detailed report on a full-scale burst testing program proposed to validate the facture propagation control design.

The tolling methodology proposed by Alliance involved a demand charge (a reservation charge for the right to transport gas), a commodity charge for volumes actually transported, and an in-kind charge for fuel, and would be set on a cost-of-service basis and include a capital efficiency incentive. Alliance proposed a volumetric tolling system (where shippers are billed according to volumetric capacity contracted for), which the NEB accepted as best respecting the principle that tolls should reflect the cost of service provided. It rejected various intervener suggestions that thermal-based tolls were more appropriate. The NEB found, especially in light of the facts that the tariffs and tolls were negotiated between Alliance and its shippers and none of the shippers objected to the proposed toll methodology, that the proposed tariff and tolling methodology provided long-term stability and certainty for shippers, resulting in tolls that were just and reasonable, with no unjust discrimination.

(iv) *GH-3-98: TransCanada PipeLines Limited — Facilities*[149]

The NEB released this decision in November 1998 approving an application by TransCanada Pipelines Limited ("TransCanada") to construct facilities on its natural gas

[149] *Re TransCanada PipeLines Limited Application dated 29 April 1998, as amended, for 1999 Facilities* (November 1998), GH-3-98 (N.E.B.).

pipeline system in Saskatchewan, Manitoba, and Ontario at an estimated cost of $402.9 million. TransCanada intended to construct facilities that would provide less than the forecast net incremental requirements for the 1999/2000 contract year and intended to rely on arrangements referred to as the "Alternative Mechanism" to satisfy the remaining volumes. These arrangements included temporary or long-term acquisition of capacity on the secondary market, capacity exchanges, capacity loans, or any other arrangement proposed by gas market participants. TransCanada intended to consult with its stakeholders and its Tolls Task Force before contracting for the Alternative Mechanism, including an appropriate request for proposals ("RFP") process.

As an intervener, Vector Pipeline Limited Partnership proposed the use of an RFP to solicit Alternative Mechanism proposals before NEB approval of TransCanada's application. CAPP took the position that TransCanada should immediately canvass its shippers to determine if there were additional capacity that shippers would be prepared to relinquish. The NEB took the view that TransCanada's reliance on the Alternative Mechanism was an appropriate means of reducing the risk of firm service customers not renewing their contracts as well as reducing the risk associated with pipe and compressor cancellation costs. The NEB also did not find it necessary to require TransCanada to seek proposals for capacity from its customers. The NEB was not convinced that proposals raised by other parties would achieve competitive results with better choices and lower prices for consumers. The NEB also noted that TransCanada had made a reasonable effort to ascertain its future capacity requirements.

The NEB was generally satisfied with TransCanada's forecasts and proposed arrangements for domestic and export shippers. However, some concern was raised regarding precedent agreements with shippers that had been terminated or under which commitments were reduced. In response to these concerns, the NEB imposed a condition that precedent agreements underpinning the expansion capacity be converted to firm transportation service contracts. TransCanada had to also demonstrate that existing firm service transportation service contacts had been amended to reflect the energy conversion requirements.

The NEB also granted TransCanada an exemption from the requirement not to begin construction without board approval of the plans, profiles, and books of reference, subject to the condition that TransCanada had to obtain all the required land rights prior to construction.

Four interveners, including three First Nations groups, expressed concerns regarding land use, environmental issues, and socio-economic matters. The NEB found that TransCanada had appropriately addressed these concerns and had reached agreement with two of the groups on a protocol for including First Nations in the construction contract process. It imposed a condition that TransCanada report to the NEB on the progress of it aboriginal policy and on any negotiations with the three groups. Pursuant to the environmental screening report, the NEB determined the work proposed was not likely to cause significant adverse environmental effects. They also found that TransCanada's responses and undertakings to various other environmental organizations and departments were adequate but required TransCanada to respond to certain specific concerns as a condition to the order.

In the end, the NEB considered that the proposed facilities were economically feasible, that they would likely be used at a reasonable level over their economic life, that the demand charges would be paid, and that the use of the Alternative Mechanism was an adequate means of mitigating the risk associated with the uncertainty regarding TransCanada's future requirements.

(vi) *MH-3-98: Maritimes & Northeast Pipeline Management Ltd. — Detailed Route Hearings*[150]

Following detailed route hearings held in the summer of 1998 and video hearings conducted in January 1999, the NEB, in a decision released 30 October 1998, and 26 January 1999, approved M&NP's proposed detailed route for its pipeline from Goldboro, Nova Scotia, to St. Stephen, New Brunswick, in thirteen out of seventeen cases. The general route for the pipeline, along with a one-kilometre-wide pipeline corridor, which would ship natural gas developed by Sable Offshore Energy Project ("SOEP") from the SOEP gas plant near Goldboro to markets in the Maritimes and northeastern United States, was previously approved in December of 1997. A twenty-five-metre right-of-way was selected by M&NP based on a number of considerations, including potential environmental impact, construction costs, and number of properties affected. Fifteen landowner objections were heard at the hearings which were held in four locations in Nova Scotia and New Brunswick.

Several parties raised concerns about living in proximity to a natural gas pipeline on the grounds of safety and risk of a potential incident. However, the NEB took the view that, by imposing high-standard technical requirements for pipeline systems and continually monitoring pipeline integrity, safety risks were minimal. Furthermore, a thirty-metre safety zone allows landowners to continue to carry out usual activities; the only restrictions involve excavation by power-operated equipment or explosives and construction of facilities within the thirty-metre safety zone.

Objections by landowners related to construction methods, impact of the route on property values, safety, impact on subdivision plans, impact on use of the land, impact on agricultural and timber operations, and impact on a wilderness camp. Objections were also heard from two holders of mineral exploration licenses related to the impact of the route on their ability to undertake exploration and projects. In the decision released 30 October 1998, the NEB reserved its decision in two of the cases in order to direct M&NP to conduct a detailed evaluation of its proposed route and other viable

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150 *Re Maritimes & Northeast Pipeline Management Ltd. Application dated 24 February 1998 for approval of the Plan, Profile and Book of Reference respecting the detailed pipeline route from Goldboro, N.S. to St. Stephen, N.B.* (October 1998), MH-3-98 (N.E.B.); *Re Maritimes & Northeast Pipeline Management Ltd. Detailed Route Hearing in the Case of Franklin Irving*, letter decision dated 26 January 1999 (N.E.B.); and *Re Maritimes & Northeast Management Ltd. Detailed Route Hearing in the Case of William (Billy) MacDonald*, letter decision dated 26 January 1999, (N.E.B.).

alternates. It approved all but two of the rest, where the NEB decided that alternate routes were more attractive. In a decision released 26 January 1999, regarding the remaining two landowners, the NEB determined that M&NP failed to consider the uniqueness and special circumstances of a wilderness camp and failed to consult with the landowner in its route selection. The NEB felt that the pipeline right-of-way would have a significant and lasting negative impact on the operation of the camp and on balance, that the alternate route suggested by the landowner was the best possible detailed route.

(vii) *MH-4-98: Sable Offshore Energy Inc. — Detailed Route Hearings*[151]

Following hearings held in Halifax in August, the NEB released its decision in October of 1998 approving the detailed route proposed by SOEI for a subsea pipeline from the Thebaud platform to landfall near Goldboro, Nova Scotia, and an offshore pipeline from the landfall point to the inlet of the gas processing plant located east of Goldboro, Nova Scotia. Of note in this decision is the NEB's comment that it was regrettable that SOEI did not consult directly or meaningfully with holders of mineral exploration licenses during the planning phase, and that SOEI may have commenced its relationship with these holders in a negative fashion. The license holders objected to the proposed route on the basis of adverse effects on their mineral exploration activities and the lack of consultation provided by SOEI. In spite of this, the NEB was satisfied that, in both cases, the route proposed by SOEI was the best possible detailed route.

(viii) *MH-2-98: Trans Quebec and Maritimes Pipeline Inc.'s PNGTS Extension*[152]

In a decision released 14 August 1998, issued in six parts, one for each area affected, the NEB approved the detailed pipeline route proposed for the extension from Lachenaie, Quebec, to the Canada/United States border near East Hereford, Quebec, for extension to the Portland Natural Gas Transmission System ("PNGTS Extension") as the best possible route.

In spite of the objections by landowners and a coalition group, which filed several alternate routes which avoided residential areas and homes, the NEB found that the evidence did not support the alternatives as better routes.

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151 *Re Sable Offshore Energy Inc. application dated 9 June 1998 for approval of the Plan, Profile and Book of Reference respecting the detailed route of a subsea pipeline from the Thebaud platform to landfall near Goldboro Nova Scotia; and an onshore pipeline from the landfall point to the inlet of the gas processing plant located east of Goldboro, Nova Scotia* (October 1998), MH-4-98 (N.E.B.).

152 *Re Application dated 7 April 1998 by Trans Québec & Maritimes Inc., pursuant to section 33 of the National Energy Board Act, for approval of the Plan, Profile and Book of Reference respecting the detailed route for the PNGTS Extension, a natural gas transportation system from Lachenaie to East Hereford, in the Province of Quebec* (August 1998), MH-2-98 (N.E.B.).

(ix) *GH-1-98: Northstar Energy Corporation — Facilities*[153]

In this decision released 26 May 1998, the NEB was faced with a challenge to its jurisdiction from the Alberta Department of Energy ("Energy"). Following a public hearing held in March and April, 1998, the NEB approved the application for a 7.2-kilometre pipeline from Northstar Energy Corporation's ("NEC") Coleman gas plant located west of Coleman in Savanna, Alberta, through the Phillips Pass to connect to the Alberta Natural Gas Company Ltd. ("ANG") main transmission pipeline west of the Alberta/British Columbia border. It also rejected Energy's motion regarding jurisdiction. Energy had relied principally on the decision of *Ontario (A.G.)* v. *Winner*[154] where the Privy Council had determined that a carrier who is substantially an internal carrier should not be allowed to put himself outside provincial jurisdiction by starting his activities across the border; that issue was to be decided on the facts of the case and the pith and substance of the act or regulation. In this case, Energy argued that the inherent character of the pipeline, which extends only ten metres across the border and 99.9 percent of which is within Alberta, was to carry on intra-provincial business. Energy also argued that there was no technical or business reason for the inter-connection to be in British Columbia other than NEC's attempt to get itself within NEB jurisdiction. There was no question the project was artificially designed to cross the border, as NEC confirmed the project was designed to cross the border to eliminate uncertainty over NEB jurisdiction and avoid delay in the event that jurisdiction was questioned.

The NEB took the position that there is an important distinction between a "work" and an "undertaking." Relying on *Montreal* v. *Montreal St. Ry,*[155] where it was held that a "work" is a physical thing and an "undertaking" is an arrangement under which physical things are used, the NEB held that a pipeline was clearly a "work" in the ordinary sense of the term, while the operation of the pipeline may constitute an "undertaking." Further, the NEB stated that Energy did not provide any precedent holding that a work which crossed a border was not properly within federal jurisdiction. The cases cited by Energy concerned undertakings and not works. The NEB also stated that to grant Energy's motion and decline jurisdiction would mean that the Alberta Energy and Utilities Board ("EUB") would not be able to regulate the proposed pipeline because it crossed a provincial border; it would contravene the *NEB Act* for the EUB to assume jurisdiction over an inter-provincial pipeline.

The NEB also made a decision on an application by Advantage Pipeline Company Inc. ("Advantage") that NEC should have applied under s. 52 of the *NEB Act* rather than s. 58 because the existing seventy-one-kilometre raw gas gathering pipeline and gas plant were functionally and operationally integrated with the proposed Coleman line and were commonly owned, managed, controlled, and directed, and thereby constituted a single federal undertaking. Advantage relied on the Supreme Court of Canada

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153 *Re Northstar Energy Corporation application dated 23 May 1997* (May 1998), GH-1-98 (N.E.B.).

154 [1954] A.C. 541 at 582 (P.C.) [hereinafter *Winner*].

155 [1912] A.C. 333 at 342 (P.C.).

decision in *Westcoast Energy* v. *Canada (National Energy Board)*[156] and the Federal Court of Canada decision in *Alberta (A.G.)* v. *National Energy Board*,[157] otherwise known as the "Pesh Creek Reference" which stated that, once it is established the NEB has jurisdiction over a single undertaking consisting of a pipeline greater than forty-kilometres in length, the NEB has no jurisdiction under s. 58 to approve that pipeline. The NEB decided that the facts in this application were distinguishable from the Pesh Creek Reference, because that project concerned the construction of an entirely new undertaking, not just a new pipeline, and the issue raised was whether the whole facility should have been before the NEB for approval under s. 52. In the present application, the NEC upstream facilities were clearly under provincial jurisdiction and had been in operation for decades. Given that the existing NEC facilities were not under federal jurisdiction, the NEB concluded that NEC applied under the appropriate section of the *NEB Act* for the operation and construction of the pipeline.

For tolls, tariffs, and transportation, the NEB was satisfied regarding NEC's financial arrangements and its proposed five- and ten-year toll structure incorporated into a memorandum of understanding. Arguments were raised by interveners that the proposed pipeline was not in the public interest and that the diameter of the pipeline should be larger than the NPS 16 proposed by NEC. Concern over the size of the pipeline related largely to accommodating present and future capacity requirements and to minimizing cumulative environmental impacts on the region. It was significant that there were two potential pipeline projects applying for routes through Phillips Pass and concern that the area could not withstand the effects.

Vigorous opposition to the pipeline was raised by parties including Advantage, NOVA Gas Transmission Ltd. ("NGTL"), and Pan-Alberta Gas Ltd. ("Pan-Alberta"). Advantage submitted that its own proposal for a NPS 48 pipeline, currently before the EUB, could better achieve the objectives of competitive transportation rates and sufficient capacity to effectively and economically use the remaining space through the restricted area of the Phillips Pass. Currently, all volumes shipped out of the province from the Coleman gas plant were shipped on the NGTL system. NGTL argued that the sole justification for this pipeline was NGTL's current postage stamp rate for firm service delivery from the Coleman gas plant to the inter-connection with ANG's facilities, and furthermore that the volumes intended to flow on the proposed pipeline, could, presently and in the future, be transported on NGTL's facilities. Pan-Alberta echoed comments that the pipeline was not needed to transport existing or forecast gas and had been proposed solely to achieve lower transportation costs for NEC and third-party shippers. The NEB, however, was not persuaded by these arguments and found that the pipeline was appropriately sized for present and anticipated demand for service through the Phillips Pass and that future capacity needs could be achieved without further disturbance of the pass. Furthermore, the NEB was of the view that it would be possible to construct an additional pipeline through the pass if needed and that no evidence was presented regarding the environmental effects on the pass that it could not withstand two pipelines.

156 [1998] 1 S.C.R. 322.

157 (1997), 208 N.R. 154 (F.C.A.).

The NEB found that the potential offloading of volumes over and above the amount currently flowing on the NGTL system was speculative, with a low probability of negative effects. Furthermore, the offloaded volumes relative to the NGTL system as a whole were relatively immaterial — less than 2 percent of natural gas currently flowing through NGTL to the ANG system. Also, all parties agreed that within six or seven years there would be increased demand for capacity into the ANG system. The NEB also found that the two systems offered a different suite of services at significantly different prices and that the Coleman pipeline offered the potential for choice; the public interest usually is served by allowing competitive forces to work and offering choice to producers.

(x) *OH-1-98: Interprovincial Pipe Line Inc. — Facilities and Toll Methodology*[158]

In this decision, released in June of 1998, the NEB approved the "Terrace Phase 1 Expansion Program" in the face of minor opposition. The expansion program involved the construction of fifteen new sections of pipeline and related facilities to connect to existing sections to create a fifth pipeline between Kerrobert, Saskatchewan, and the international border near Interprovincial Pipe Line Inc.'s ("IPL") Gretna pump station in Manitoba. The NEB also approved a negotiated settlement detailing a tolling agreement which had been ratified by CAPP members and under which there would be a sharing of risks and benefits between IPL and its shippers.

The NEB was satisfied on most aspects of the project. Although disputed by Express Pipeline Ltd. ("Express"), the NEB accepted IPL's market, disposition, and throughput forecasts as reasonable. The NEB further noted that provincial governments and industry were strongly supportive of the expansion and noted that benefits could include the production of crude oil that would otherwise be shutin or sold to less attractive markets due to apportionment on IPL. Thus, the potential benefits likely justified the construction of the facilities.

The NEB was not, however, prepared to provide a blanket approval for IPL's proposed alternative crossing methodologies in the absence of information on the technical feasibility of directional drilling. It required IPL to file a report on the feasibility of directionally drilling the affected rivers and to obtain approval for each river prior to construction. It also ordered IPL to re-evaluate its existing Line 2 internal corrosion program addressing potential corrosion issues associated with laminar flow and to file the results with the NEB.

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158 *Re Interprovincial Pipe Line Inc. Application dated 2 December 1997, as amended, for the Terrace Phase I Expansion Program* (June 1998), OH-1-98 (N.E.B.).

(xi) *Key Documents Related to the NEB's Decision on the Framework for Light-Handed Regulation*[159]

In a letter decision,[160] framework and key documents dated 25 June 1998, the NEB approved the Framework for Light-Handed Regulation ("Framework") which amended the multi-year incentive toll settlement dated 16 May 1997, approved by the NEB in its RH-2-97 reasons for decision.[161] The Framework provides the mechanism by which Westcoast's tolls for gathering and processing services will be negotiated with shippers. The Framework includes: an introduction which states that Westcoast and its stakeholders propose a new model of regulation to address increasing competition in the provision of gathering and processing services in British Columbia; a fair dealing policy intended to ensure all parties desiring or obtaining service from Westcoast are treated fairly; a contracting practice section which establishes parameters for Westcoast to negotiate individual agreements with shippers and which provides that Westcoast will continue to offer service under standard contracts to those who do not wish to negotiate individual contracts; a provision of market information and confidentiality of contracts section which addresses the means by which information concerning the contracts negotiated between Westcoast and shippers will be made available to others; a complaint process which provides a process enabling parties to resolve disputes by mediation, arbitration, or judication; an asset utilization and disposition policy which establishes that Westcoast is responsible for the utilization, and loss or gain on disposition of its gathering and processing facilities; and an inter-connection policy designed to enable owners of third-party facilities to inter-connect with Westcoast, thus furthering the competitive environment.

(xii) *Letter Decision re: Express Pipeline Ltd. — Section 21 Application*[162]

The NEB rejected Express' request to vary the NEB's decision to enact a regulation[163] adding Express to Schedule I, Part I of the *National Energy Board Cost Recovery Regulations*.[164] The NEB reiterated that the criteria for determining how a company will be treated for the purposes of cost recovery had always been based on size, throughput, and cost of service, and not on the expected regulatory workload generated by the company. Based on size and throughput, Express was more comparable to companies in Part I of the schedule than those in Part II. Express submitted that the burden of cost recovery would fall on the shareholders. However, the

159 Key documents related to the *Board's Decision on the Framework for Light-Handed Regulation in the matter of Westcoast Energy Inc., Framework Summary* (June 1998), (N.E.B.).

160 *Ibid.* at 2-5.

161 *In the Matter of Westcoast Energy Inc. Application dated 6 November 1996, as amended on 20 May 1997, for Tolls or Methodologies for fixing Tolls over the period 1 January 1997 to 31 December 2001*, Part I (August 1997), RH-2-97 (N.E.B.); and *Re Westcoast Energy Inc. Multi-year Incentive Toll Settlement 1 January 1997 to 31 December 2001*, Part II (August 1997), RH-2-97 (N.E.B.).

162 *Re Express Pipeline Section 21 Application — Cost Recovery Regulations*, letter decision dated 19 June 1998, (N.E.B.).

163 S.O.R./97-271.

164 S.O.R./91-7.

NEB noted that the tolls were set by Express before key regulatory decisions were made including treatment for cost recovery and status as a "Group 1" or "Group 2" company. The NEB also reiterated that there was no automatic correlation between "Group 2" status and Schedule I, Part II status for cost recovery purposes. The NEB stated that it was up to the company to arrange its contracts to flow through expenses associated with cost recovery to the shippers.

(xiii) *GH-2-98: AEC Suffield Gas Pipeline Inc. — Facilities*[165]

The NEB approved an application by AEC Suffield Gas Pipeline Inc. ("AEC Suffield") to construct and operate a natural gas pipeline from southeastern Alberta to southwestern Saskatchewan. The 114-kilometre pipeline will begin near the Suffield military block in Alberta, extend along the southern end of the military block, and then proceed northeast to join the TransCanada system near Burstall, Saskatchewan.

In this decision released 31 July 1998, the NEB once again faced a challenge to its jurisdiction from Energy in the face of what it characterized as a colourable attempt to avoid provincial jurisdiction. Energy submitted that the proposed project was designed to avoid the provincial regulator and that the NEB could not sever a project into parts, but had to take the project as it found it, unless the project was designed to avoid proper provincial jurisdiction and, in such a case, the project would fall within the colourability principle of *Winner*. Energy also submitted that "works" and "undertakings" were to be read disjunctively, that the subject application represented both a work and an undertaking, and further, that, if the colourability principle did not apply to a work, it did apply to an undertaking, and the work was subsumed by the undertaking.

The NEB found that a pipeline was clearly a "work" in the ordinary sense, and, while the operation of a pipeline and associated works may constitute an "undertaking," the pipeline was a physical thing that was a work within the meaning of paragraph 92(10)(a) of the *Constitutional Act, 1867.*[166] As such, the application for the construction and operation of a pipeline which crosses a provincial boundary was *prima facie* within the NEB's jurisdiction as it was a work and undertaking referred to in paragraph 92(10)(a) as "connecting the Province with any other or others of the Provinces, or extending beyond the Limits of the Province." Furthermore, even if the colourability principle did apply, Energy had the evidentiary burden of establishing that the true character of the undertaking was intraprovincial and sufficient evidence was not provided.

While generally satisfied with forecasts, the NEB conditioned the certificate to require an affidavit confirming that transportation service agreements had been executed for the subscribed capacity.

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165 *Re AEC Suffield Gas Pipeline Inc. Application dated 10 September 1997* (July 1998), GH-2-98 (N.E.B.).

166 (U.K.), 30 & 31 Vict., c. 3, reprinted in R.S.C. 1985, App. II, No. 5.

AEC Suffield proposed to be a commercially at-risk pipeline with market-based tolls for transmission services. The toll design for firm service transportation incorporated a long-term incentive approach, offering lower tolls for a longer-term commitment. The NEB found that the proposed firm service tolls would insulate shippers from changes in transportation costs and some of the risks associated with more traditional tolling methodologies; the pipeline company would assume those risks but in turn could be able to earn a return that would appropriately compensate it. In light of this, as well as other considerations, the NEB found the tolls just and reasonable and accepted those proposed by AEC Suffield.

Considering AEC Suffield's proposed mitigative measures and those set out in the conditions, the NEB found the pipeline would not likely cause significant adverse environmental effects. The NEB also acknowledged the commitment to build parallel to existing rights-of-way and to use those where available.

(xiv) *MH-1-98: Souris Valley Pipeline Limited — Facilities*[167]

The NEB approved an application by Souris Valley Pipeline Limited ("SVP") to construct and operate a sixty-one-kilometre carbon dioxide transmission pipeline in southeastern Saskatchewan, following a public hearing held 4 May 1998, in Regina, Saskatchewan. The pipeline would extend from a point at the international boundary approximately twenty-five kilometres southwest of Estevan, Saskatchewan, to a terminus approximately 3.2 kilometres northeast of Goodwater, Saskatchewan, and was planned to transport carbon dioxide from the proposed Dakota Gasification Company CO_2 pipeline project in North Dakota to the existing Weyburn oilfield for use in the implementation of the "Weyburn Miscible Flood Project," which was expected to extend the life of the existing oilfield by twenty-five years. This was the first hearing of the NEB for the construction and operation of a commodity pipeline. Commodities other than oil or gas came under NEB jurisdiction after authority was transferred from the National Transportation Agency as a result of the *Canada Transportation Act*,[168] which came into force 1 July 1996.

Order MO-CO-3-96 issued by the NEB exempted commodity pipelines from the provisions of the *Onshore Pipeline Regulations*.[169] Given this exemption, the NEB included many of the issues from the regulations as conditions. The NEB was satisfied regarding the need for the pipeline and with the proposed methods of regulation and financing of the project.

The NEB was satisfied with the proposed design facilities, which were to meet CSA standards for a class 1 sour service CO_2 pipeline. The NEB was also satisfied with the proposed operating conditions and control measures, however, two conditions relating to internal corrosion would be included in the certificate. It did note that SVP's

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167 *Re Souris Valley Pipeline Limited Application dated 10 October 1997, as amended, for Facilities* (October 1998), MH-1-98 (N.E.B.).

168 S.C. 1996, c. 10.

169 S.O.R./89-303 [hereinafter *OPR*].

application contained many unit conversion errors and expressed concern that the final design be free of similar mistakes which could jeopardize safety of the public and employees. The NEB noted its general satisfaction with SVP's fracture prevention and safety measures.

In addition to the environmental mitigative measures set out in the application, SVP gave undertakings related to protection of wildlife periods, planned blow down events, and the storage of dangerous or hazardous materials, among other things.

b. Memoranda of Guidance, Guidelines, Notices, and Information Bulletins

(i) *Guidelines re: Onshore Pipeline Regulations, 1999*[170]

Pursuant to s. 48(2) of the *NEB Act*, the NEB instituted the *OPR*. However, based on findings of past inquiries, safety and environmental issues, and changed technical standards, the NEB proposed the current *OPR* be replaced with the new version and its companion guidelines. The companion guidelines contain detailed and expanded explanations of a number of sections in the regulations. The purpose of the guidelines is to assist industry in complying with the requirements of the regulations. The NEB's intent is to promote increased industry responsibility and allow additional flexibility, efficiency, and the opportunity to implement improved safety and environmental techniques in a more timely manner.

(ii) *Notice re: Financial Regulatory Audit Policy*[171]

The NEB issued this notice in response to issues arising from negotiated incentive toll settlements. Pursuant to several companies negotiating incentive toll settlements, the NEB informed the parties that its financial regulatory audit would be focused on ensuring compliance with both the *Oil Pipeline Uniform Accounting Regulations*[172] and the *Gas Pipeline Uniform Accounting Regulations* (collectively the "Uniform Accounting Regulations").[173] However, the NEB has found this restricts its ability to satisfactorily meet its regulatory responsibilities. With the advent of negotiated incentive toll settlements, the NEB's primary means of assessing the effectiveness of pipeline companies was through shipper complaints, however, the absence of formal complaints does not necessarily indicate satisfaction. Furthermore, since the advent of incentive settlements, the NEB has had concerns about whether it was maintaining an in-depth knowledge of the operations of pipeline companies sufficient to ensure it was able to meet its responsibilities under the *NEB Act*. With fewer toll hearings, there is less opportunity for the NEB's staff to access detailed information and update understanding of the operations of the regulated companies. The NEB believes it has

170 *Letter from N.E.B. to whom it may concern* (18 January 1999) (re Guidelines for the *Onshore Pipeline Regulations, 1999*).

171 *Letter from N.E.B. to Pipeline Companies under the Board's Jurisdiction* (23 February 1999) (re Financial Regulatory Audit Policy), online: N.E.B. <http://www.neb.gc.ca/pubs/auditp.t\htm> (last modified: 26 March 1999).

172 C.R.C., c. 1058.

173 S.O.R./83-190.

a role to play in auditing settlements to ensure they are working as intended. Therefore, the NEB has decided to expand its current audit policy for those companies that have negotiated incentive toll settlements to allow its staff to examine areas outside the scope of compliance audits. The information would be summarized and reported in a draft audit report upon which the company will have an opportunity to comment. The final report would then be a public document. Upon prior notice, the NEB could also examine items apart from those normally included in its financial regulatory audits, for example, processes maintained by companies to ensure certificate conditions are satisfied.

A revised audit policy is attached to the notice. Its objectives are to determine if the company's system of accounts has been maintained in accordance with the Uniform Accounting Regulations, to determine whether the company has complied with the *NEB Act*, decision, order, and other accounting and reporting directives, to verify financial information in applications and submissions, to examine whether cross-subsidies have been made at the expense of toll payers, and to maintain up-to-date knowledge of the company. The NEB will observe guidelines on confidentiality which include not placing copies of documents on the public record, allowing a company to request only senior officers have access to sensitive information, and prohibiting the NEB from using documents obtained during an audit as direct evidence in a public proceeding or approach. The NEB will not duplicate the work of external auditors but might be interested in examining the company's regard for economy and efficiency, its policies and procedures for establishing performance objectives and evaluating results, and its knowledge of other areas in order to maintain in-depth and up-to-date knowledge of the company's operations and to assess the effectiveness of the incentive settlements.

Each audit plan must be approved by the NEB before field work commences, and the company is notified of the scope of examination and consulted on timing. An investigation will be initiated should the NEB become aware of a violation of an act, regulation, decision, order or other directive. Best efforts will be made to conduct audits when there are no toll applications pending. If voluntary compliance is not obtained, the matter shall be referred to the NEB for enforcement.

(iii) *Letter*[174] *re: Regulations Respecting the Coordination by Federal Authorities of Environmental Assessment Procedures and Requirements*[175] *Pursuant to the Canadian Environmental Assessment Act*

This letter outlines the key aspects of the *FCR* which were published on 30 April 1997. The *FCR* are anticipated to streamline the environmental assessment process, to provide greater certainty regarding responsibilities for federal environmental assessment, and to establish timelines to fulfil those responsibilities. Identification of, coordination of, and consultation among federal authorities are key elements of the *FCR*.

174 *Letter from National Energy Board to Pipeline Companies Preparing Applications under the National Energy Board Act* (31 March 1998), online: N.E.B. <http://www.neb.gc.ca/pubs/mogfcr.htm> (last modified: 10 September 1998).

175 S.O.R./97-181 [hereinafter *FCR*].

c. Reports

(i) *Canadian Energy Supply and Demand to 2025: Round 2 Consultation Package*[176]

This package was designed to seek consultation and input on the preliminary results of the NEB's work on its long-term outlook of the supply and demand of energy in Canada. The report will provide an analysis of energy trends, issues, and developments impacting Canada over the next quarter century. A final report is expected in late spring of 1999.

(ii) *1999 — 2000 Estimates: Part III — Report on Plans and Priorities*[177]

This report, issued 25 March 1999, presents an overview of the NEB's mandate, objectives, and operating environment that form the basis for planned spending. It also details the planning perspective as well as information regarding performance, supplementary personnel, structure, and financial information. The report contains key goals and strategies for the NEB from 1999 to 2002 including revision of a number of regulations to reflect an emphasis on goal-oriented regulations and an increased emphasis on maintenance and risk management, clarification of assessment standards from environmental protection and refinement of approaches, completion of the report on *Canadian Energy Supply and Demand to 2025*, review of incentive regulation, identification of scope and prioritization of a review of the NEB's approach to discharging its major regulatory responsibilities, implementation of the electronic regulatory filing strategy, establishment of guidelines, and definition of roles of the NEB and regulated companies in responding to the information needs of the communities and landowners.

(iii) *1998 Report of the Auditor General of Canada*[178]

On 29 September 1998, the Auditor General of Canada issued the findings of an audit it conducted on the NEB in 1998. The overall audit objective was to assess whether the NEB was fulfilling its obligations as a regulatory body in the areas subject to examination. In particular, the Auditor General looked to whether the NEB has identified changing circumstances, used appropriate surveillance and enforcement methods, developed efficient management interfaces with other jurisdictions, established efficient and cost-effective operations and cost recovery practices, and carried out appropriate monitoring and reporting of operations and managerial performance. Key management and operational processes were also examined. On 29 September 1998, the NEB announced that it agreed with all the recommendations contained in the report,

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176 N.E.B., *Canadian Energy Supply and Demand to 2025: Round 2 Consultation Package* (Update 6 January 1998).

177 N.E.B., *1999 — 2000 Estimates: Part III — Report on Plans and Priorities* (March 1999).

178 *1998 Report of the Auditor General*, online: Office of the Auditor General of Canada <http://www.oag-bvg.gc.ca /domino/reports.nsf /html /98menu_e.html> (date accessed: 28 April 1999).

and in fact, that many had already been implemented. The NEB stated that the recommendations were consistent with the direction in which the NEB was moving.

(iv) *Probabilistic Estimate of Hydrocarbon Volumes in the Mackenzie Delta and Beaufort Sea Discoveries*[179]

This study is the first comprehensive probabilistic estimate of the discovered resources for the Beaufort-Mackenzie Basin. The current estimates are that between 93 million cubic metres (0.585 billion barrels) and 229 million cubic metres (1.44 billion barrels) of recoverable oil and between 186 billion cubic metres (6.57 trillion cubic feet) and 349 billion cubic metres (12.2 trillion cubic feet) of marketable gas has been discovered in the Mackenzie Delta-Beaufort Sea region. These estimates are at the 90 percent confidence interval. A brief analysis shows that approximately half of the recoverable oil and just under half of the marketable gas are contained in fields that have just one or two pools. However, future drilling within the fields may reveal additional pools with the potential for increasing the resources. The NEB's estimate of gas resources in the current study are lower than those estimated earlier in its reasons for decision GH-10-88.[180] The differences are largely due to the recently acquired three-dimensional seismic surveys over Taglu, Niglintgak, and Kumak and also to the more conservative estimate of reservoir parameters following an in-depth analysis. The gas presented in this study is the sum of non-associated gas and associated gas.

(v) *Non-Associated Natural Gas Resource Assessment Study*[181]

This study, which was undertaken to provide an analytical review of undiscovered gas resources in Saskatchewan, estimates that the undiscovered marketable non-associated gas potential for Saskatchewan is 45.6 billion cubic metres (1.6 trillion cubic feet) or 22 percent of the ultimate non-associated gas potential. The range of undiscovered marketable non-associated gas potential is from 21.0 billion cubic metres (0.7 trillion cubic feet), with a 90 percent chance that the area contains that amount, up to 69.3 billion cubic metres (2.9 trillion cubic feet), that has a 10 percent chance of occurrence. Much of the mean gas potential estimate, amounting to 40.1 billion cubic metres (1.4 trillion cubic feet), is forecast to be from non-associated Viking and Mannville gas pools. The estimates appear to support the position that Viking and Mannville play groups will provide the bulk of the marketable gas potential.

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179 N.E.B., *Probabilistic Estimate of Hydrocarbon Volumes in the Mackenzie Delta and Beaufort Sea Discoveries* (December 1998).

180 *Re Esso Resources Canada Limited, Shell Canada Limited, and Gulf Canada Resources Limited Applications Pursuant to Part VI of the National Energy Board Act for Licenses to Export Natural Gas* (August 1989), GH-10-88 (N.E.B.).

181 N.E.B., *Non-Associated Natural Gas Resource Assessment Study* (October 1998).

d. Speeches

(i) *The Role of Regulation in the North American Gas Market: A Canadian Perspective*[182]

In this speech, Mr. Vollman, Chair of the NEB, focused on the economic regulation of pipelines and other issues. Mr. Vollman stressed the current climate of reducing regulatory burdens on industry, eliminating the adversarial atmosphere that had pervaded hearings in the past, and aligning the interests of shippers and pipeline companies. Part of this is the disenchantment by the early 1990s with cost-of-service regulation and the exploration of alternatives including negotiated settlements and incentive regulation. The NEB is moving forward with its support for market solutions and has signalled its preference for negotiated settlements with incentive components and reliance on market forces. The NEB is working toward enhanced clarity and consistency in legal and scientific frameworks for environmental assessment, in response to the uncertainty which can arise in combining the requirements of the *Canadian Environmental Assessment Act* and the *NEB Act*, enhanced public confidence in the safety of NEB-regulated facilities, improved provision of information on energy resources and markets, enhanced ability of public participation, and improved access to information.

(ii) *The Emerging Context for the Physical Regulation of Pipelines*[183]

Mr. Vollman discussed the changing role of the regulator as it is required less to arbitrate economic issues but is increasingly required to monitor more closely the physical regulation of pipelines. In an atmosphere of increased pressure to keep transportation rates down, the potential exists for tension between increased competition and increased incentives, which may arguably promote skimping on safety and environmental measures. There is also a trend toward more knowledgeable and visible representation from the general public and special interest groups which the NEB must deal with. Part of this is related to public confidence in pipeline safety. The NEB sees its role as ensuring that safety remains a top priority with companies, promoting the use of alternative dispute resolution mechanisms, working toward increased sharing of non-competitive information, coordinating the results of research priorities and dollars, encouraging the use of new cost-effective technologies, and developing enhanced systems for information management.

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[182] K.W. Vollman, "The Role of Regulation in the North American Gas Market: A Canadian Perspective" (INGAA 1998 Annual Meeting, Vancouver, British Columbia, 28 September 1998) [unpublished].

[183] K.W. Vollman, "The Emerging Context for the Physical Regulation of Pipelines" (Presentation to the International Pipeline Conference, Calgary, Alberta, 9 June 1998) [unpublished].

B. ALBERTA

1. ALBERTA ENERGY AND UTILITIES BOARD

a. Decisions

(i) *Decision 98-11: Caprice Holdings Inc. Application to Construct and Operate an Oil Field Waste Management Facility in the Brazeau/Elk River Area*[184]

Pursuant to paragraph 26(1)(g) of the *Oil and Gas Conservation Act* and Guide 58 entitled *Oil Field Waste Management Requirements for the Upstream Petroleum Industry*,[185] Caprice Holdings Inc. ("Caprice") applied for approval to construct and operate an oil field waste management facility to be located on a site adjoining its existing custom treating operation.

The Energy and Utilities Board ("EUB") accepted the need for the proposed facility on the basis of Caprice's evidence that its customers indicated a new waste management facility was needed in the area. Acknowledging that the level of natural protection afforded by the native materials was less than that maintained by Caprice, the EUB nonetheless found the site acceptable, subject to the implementation of an enhanced groundwater monitoring system to ensure the regional aquifer was protected.

Despite interveners' objections, the EUB indicated it was more inclined to issue a deficiency letter outlining the information required than to reject the application when applications present a good measure of the necessary data but require supplementary information to complete the process. Although an environmental impact assessment was not required for facilities of this type, the EUB requested that it be provided with sufficient environmental information to satisfy itself that any impact would be appropriately mitigated.

Caprice acknowledged that the applied-for facilities had been constructed prior to the hearing and attempted to justify such action on the basis that it wanted to avoid problems associated with freeze-up. Concerns were raised that this industry practice was becoming more frequent, was potentially prejudicial to any decision rendered by the EUB, and was a threat to the integrity of the public review process. In principle, the EUB believed that all facilities under its jurisdiction should be properly licensed before any field development took place, and noted that the provisions of the *Oil and Gas Conservation Act* made it clear that no person shall commence construction of a waste management and disposal facility unless the EUB has approved the location and construction of the facility. In this case, the consequences of early construction were viewed as relatively insignificant, given that the site had already been developed for the custom treating operation.

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184 (12 June 1998), 98-11 (A.E.U.B.).

185 (November 1996).

Caprice's waste management facility was ultimately approved, subject to conditions respecting groundwater monitoring, placement of solids, maintenance and inspection of the solids storage pit, and the EUB's satisfaction with the surface water run-off management system.

(ii) *Decision 98-12: Federated Pipe Lines Inc. Application to Construct and Operate a Crude Oil Pipeline from Valhalla to Doe Creek*[186]

Federated Pipe Lines Ltd. ("Federated") applied pursuant to Part 4 of the *Pipeline Act* for a permit to construct and operate approximately twenty-seven-kilometres of pipeline for the purpose of transporting crude oil from existing facilities in Valhalla to a proposed terminal in Doe Creek. Peace Pipe Line Ltd. ("Peace") objected to the proposed pipeline, citing needless proliferation.

Peace requested the EUB to direct Federated to: (1) provide full and adequate responses to information requests about tolls, terms of service, capital costs, and operating costs; and (2) adjourn the hearing proceedings pending resolution of such matters. The EUB did not compel Federated to provide the requested information. The issues considered by the EUB included the need for the pipeline and the implications for the economic environment within which competing pipelines were developed.

In Federated's view, the purpose of the EUB's proliferation policy was to require scrutiny of pipeline applications and their denial in circumstances where no contribution to the public interest is made. This might occur where construction of the proposed pipeline sterilizes and makes redundant facilities in the ground which were capable of providing the same service, and demonstrates no other benefits or where such pipelines are built without having first obtained any commitment to their use.

Federated submitted that it had negotiated contracts with three producers to transport oil from the Valhalla area to Edmonton and had concluded ten-year contracts with these producers on its proposed pipeline.

The EUB noted that it was not persuaded by arguments solely related to proliferation to justify inhibiting competitive development of facilities, particularly where there has been some support from the marketplace. The proliferation policy should not, according to the EUB, necessarily be allowed to stifle legitimate competitive proposals where proponents are willing to invest private capital and customers are willing to enter into contractual agreements for services, unless potential effects adverse to the public interest are clear and substantiated. Pipelines were less likely than surface facilities to trigger the type of proliferation the EUB was most concerned with avoiding.

Nonetheless, the EUB's decision turned on other aspects of the application which related to the implications of its decision with respect to potential market power in the pipeline sector and the economic environment within which new pipeline development would occur. The EUB considered two options to address these issues: (1) deny the

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186 (29 May 1998), 98-12 (A.E.U.B.)

application but include a clear message that a subsequent application with respect to rates would be accommodated; or (2) approve the application while making it clear that rate regulation is an acceptable alternative in future cases. The EUB's deliberations were complicated by the need to clarify its current views on perceptions within the industry.

The EUB approved the application but noted that a regulatory approach involving some form of rate determination would be acceptable in future cases for the following reasons:

(1) The sequence of negotiations and the pattern of price reductions over time have led to benefits to some producers. There is a reasonable presumption that Peace's efforts in the negotiations were conditioned to some extent by the assumption that the regulatory environment favoured its position. Unsuccessful intervention would have introduced a regulatory bias that could have provided Peace with strength in future negotiations which did not stem from an inherent competitive advantage.

(2) Increased competition may act to mitigate market power in some circumstances. The EUB hoped that parties would have an incentive to put reasonable effort into reaching settlements that were fair and efficient instead of appealing to the regulatory process as an alternative to good faith negotiation.[187]

(iii) *Decision 98-15: Canadian 88 Energy Corp. Application to Vary or Rescind the Maximum Daily Allowable for a Horizontal Gas Well Located in the Crossfield EastField*[188]

Canadian 88 Energy Corp. ("Cdn. 88") applied to vary or rescind the maximum daily allowable production for a horizontal well drilled in a fractional section by Mobil Oil Canada Limited ("Mobil") because it believed the current use of the "Qmax" equation was inappropriate for calculating equitable allowable production for horizontal gas wells. The calculated allowable production exceeded the productive capability of Mobil's well, making production therefrom practically unrestricted in Cdn. 88's view and the cause of drainage of its offsetting lands.

Cdn. 88 requested that the EUB adopt either the "Reserve Based Qmax" methodology or an "Actual Production Based Qmax" methodology to calculate the allowable production. Mobil argued that neither method allowed for competitive operations nor were they reflective of the deliverability potential of a well. Once the area-adjusted allowable production is supplied to a well in a fractional section drilling spacing unit ("DSU"), Mobil argued the fractional section DSU is on an equivalent basis to a similar well drilled in a full section DSU. In Mobil's view, the same law of capture and competitive operations should apply to a fractional section DSU adjusted

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187 *Ibid.* at 9.

188 (26 August 1998), 98-15 (A.E.U.B.).

for area, as it applies to full section DSUs. Mobil also referred to an earlier decision of the Energy Resources Conservation Board ("ERCB") which stated:

> [B]efore approving an application for a rateable take order, the Board believes it must be convinced that a limitation of production rates is necessary because a well owner is being deprived of an opportunity to produce his share of the reserves of a pool. To demonstrate that an owner is not producing his share of reserves, the Board takes the position that the owner must be able to show that drainage is actually occurring or that it can be expected to occur with a very high degree of certainty. Additionally, the drainage must be as a result of the owner not having an opportunity to have produced his share of gas. In a case where the only limitation on production is the lack of wells or well capability, the Board considers that a producer is not being denied the opportunity to obtain his equitable share.[189]

Mobil asserted that Cdn. 88 was not denied an opportunity to obtain its equitable share as it had drilled a horizontal well on neighbouring lands.

If the maximum rate of production could adversely affect ultimate recovery from the pool, the use of the Qmax equation would be inappropriate in the EUB's opinion. Since there were no conservation issues involved, however, the appropriateness of the use of the Qmax equation was not easily determined.

The EUB was not persuaded that the law of capture, employing competitive operations, should be viewed differently for fractional section DSUs than for full section DSUs. The fact that some specific situation involves an unusual result does not mean that a regulation is ineffective. In the final analysis, the issue of whether Cdn. 88 had the opportunity to produce its share of reserves was of primary importance. The EUB reaffirmed its earlier view and stated that, where the only limitation on production is the lack of wells or well capability, it did not believe that the owner was denied the opportunity to obtain his equitable share. Accordingly, the EUB decided that its current approach for establishing the allowable production for Mobil's well should remain unchanged. The EUB noted that the circumstances surrounding this matter were somewhat unique to fractional section DSUs and suggested that cases involving off target wells may be treated differently. Cdn. 88's application was accordingly denied.

(iv) *Decision 98-16: Shell Canada Limited to Allow Lines 45 and 46 of the Carbondale Pipeline to Return to Service Pending Public Inquiry — Section 43(5) Hearing*[190]

After two failures of the Carbondale pipeline, which was designed to carry sour natural gas, the EUB received requests from neighbouring landowners to suspend operations of the entire Carbondale pipeline and to conduct a public inquiry into its operation. Concerns about pipeline integrity and potential impacts upon area residents' safety were cited by the applicants.

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189 (17 June 1988), 88-8 (E.R.C.B.) at 7.

190 (17 September 1998), 98-16 (A.E.U.B.).

Shell Canada Ltd. ("Shell") requested that the EUB confirm its earlier decision to allow lines 45 and 46 to remain in service, citing implementation of appropriate construction and repair procedures which would prevent the type of weld failure that had occurred from occurring in the future. Shell's internal pipeline corrosion inspection tool recordings actually exaggerated the depth of pitting in all but three sections of pipeline removed and examined. Shell concluded that it had been overly cautious in its analysis of test data and subsequent remedial efforts. Shell maintained that the system was not subject to systemic weaknesses and disagreed with the applicants' interpretation.

In the EUB's view, the pivotal questions in determining whether the lines should be allowed to operate pending the outcome of the public inquiry were whether the operation of the pipeline represented a material risk to the safety of the public and to what extent operating the pipeline could be of benefit to the public in the long term. The likely occurrence of some corrosion in steel pipelines which transport sour gas was accepted by the EUB, and Shell's initiation of a repair program was viewed as prudent and demonstrated a level of vigilance that should alleviate the risk of failure in the short term. In order to make the inquiry meaningful, the EUB believed as much data as possible regarding the integrity of the entire pipeline should be available. A key element for safe operation of the pipeline was the flow rate of products transported therein, and the EUB noted that Shell had committed to maintain adequate velocity within the pipeline to eliminate hold-up of liquids. The EUB was therefore satisfied that its original decision to allow lines 45 and 46 to return to service was appropriate and confirmed that such pipelines would be allowed to remain in operation pending its decision on the long-term operation of the pipeline.

(v) *Decision 98-21: Imperial Oil Resources Limited Application to Construct and Operate the ThickSilver Pipeline Project; a Blended Bitumen Pipeline and Associated Surface Facilities; Cold Lake to Hardisty*[191]

Imperial Oil Resources Limited ("Imperial") applied for a permit to construct and operate approximately 250 kilometres of pipeline for the purpose of transporting blended bitumen from its existing production facilities to an existing terminal facility and to construct related surface facilities.

Imperial argued that the need for the ThickSilver project developed as a result of future production from Imperial, Amoco Canada Petroleum Co. Ltd. ("Amoco") and Koch Oil Co. Ltd. ("Koch") in the Cold Lake area. These parties had sufficient reserves to support the project, as well as the financial strength and technological expertise required to complete further development of the region. Additional pipeline facilities in the area were necessary in the applicant's view to assure security and flexibility of capacity and to lower transportation costs. Alberta Energy Company Ltd. ("AEC") opposed the application, disagreeing with Imperial's assessment that the existing AEC Cold Lake pipeline could not be expanded to offer sufficient capacity to meet the needs of the ThickSilver proponents.

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[191] (26 November 1998), 98-21 (A.E.U.B.).

Although timing of production growth in the Cold Lake area was somewhat uncertain, the EUB was confident that development of resources in the region would proceed in the future. It therefore accepted the argument that there was a need for additional pipeline capacity to service future incremental production. The EUB recognized Imperial's substantial commitment to the Cold Lake region, making it particularly important that its transportation needs were addressed in a preferred fashion. The project would produce higher royalties to the Crown, and the EUB noted that the project would be developed at the sole risk of its proponents.

With respect to the potential for undue pipeline proliferation, Imperial took the view that the EUB should not mandate use of an inefficient pipeline which might hinder its competitiveness, while AEC took the view that the project would remove virtually all of AEC's shipments from the line and could potentially render its line a stranded asset.

The EUB was mindful that the proliferation policy was underpinned to some extent by the mandate to ensure economic, orderly, and efficient development of facilities in the public interest and, accordingly, that consideration must be had to the degree and nature of duplication represented by facilities applications. Such consideration was tempered, however, by the notion that absent adverse impact in terms of the environment, resource conservation, or public health and safety, the duplication in question must be excessive before the EUB would accept arguments related solely to proliferation to stifle normal business decisions made with marketplace support. Since Imperial and Amoco had an agreement with AEC to transport a certain minimum volume of crude bitumen on AEC's line for the following seven years, after which AEC would have fully depreciated its capital investment, the EUB was confident that development in the region would continue and that AEC should be in a position to offer a competitive toll source to attract future volumes. The EUB therefore did not consider the ThickSilver project as representing undue proliferation and approved Imperial's application.

(vi) *Decision U98084: Nova Corporation, TransCanada PipeLines Limited, Nova Gas Transmission Ltd., Novagas International Ltd., Alberta Natural Gas Company Ltd., Nova Chemicals Ltd., 747978 Alberta Ltd. and 399508 Canada Ltd. — Application for Regulatory Approvals in Connection with a Proposed Merger of Nova Corporation and TransCanada PipeLines Limited*[192]

The applicants sought regulatory approval in connection with an arrangement agreement between TransCanada and Nova Corporation ("Nova"). The EUB was asked to authorize any union of the applicants and their affiliates that may be owners of gas utilities and public utilities, to approve the merger and consolidation of the property, franchises, privileges and rights or parts thereof of Nova Gas Transmission Ltd. ("NGTL"), and to authorize NGTL to make a transfer of its shares to 747978 Alberta Ltd., which would result in that corporation owning more than 50 percent of the shares of NGTL.

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192 (19 May 1998), U98084 (A.E.U.B.).

Although a number of submissions were filed, after the withdrawal of objections by CAPP, the Small Explorers and Producers Association of Canada ("SEPAC"), and Alliance Pipeline Ltd. ("Alliance"), there were no outright objections to the application remaining at the end of the proceeding. The submissions requested detailed scrutiny to properly examine the potential impacts of the merger on NGTL's customers, stakeholders, and the public at large. Pacific Gas & Electric Company ("PG&E") expressed concern that, in the absence of appropriate conditions or guidelines, the applicants would have the incentive and ability to disadvantage western export volumes at the Alberta/British Columbia export point in favour of eastern export volumes at Empress and McNeill. The Canadian Consumers Association ("CCA") expressed concern over the potential impact on Albertans as a result of the inter-relationship of NGTL and the Alberta gas distribution utilities. The applicants submitted that there were legitimate and sound business purposes for the merger and no basis upon which to conclude that they would not fully comply with applicable regulatory requirements. They further submitted, and the EUB agreed, that it was not necessary to demonstrate what positive benefits would flow from the merger, and that the EUB's mandate was to satisfy itself of the absence of adverse impacts on affected parties.

Other parties expressed concern that they might be disadvantaged due to increased market power and that the post-merger entity would be placed in a dominant position with respect to natural gas gathering and processing. The applicants advised that competition issues were subject to the review and scrutiny by the Federal Competition Bureau and, furthermore, that the natural gas transmission businesses of Nova and TransCanada currently operated in discrete geographic markets and were complementary, rather than competing, activities. In addition, the transmission businesses would continue to be carried out in a regulated environment. With respect to concerns regarding market power in the midstream business, the applicants indicated that the combined field processing facilities of the post-merger companies would account for less than 10 percent of field processing capacity in the Western Canadian Sedimentary Basin. As the natural gas marketing affiliates of the applicants generally sold gas to different regions of Canada, overlap would exist only in serving customers in Alberta, but this market was also well under 35 percent of Alberta's total gas consumption. The EUB believed that the merger should not itself negatively impact the delivery of quality service at fair and reasonable rates, noting that the entities regulated prior to the merger would remain regulated to the same extent after the merger and that gas transmission business regulation will continue to include matters related to tariffs, rates, return on equity, additional facilities, expansions, and terms and conditions of providing service. The EUB was satisfied that there was regulatory recourse for those who may be denied access to facilities or charged an unreasonable service fee and that the EUB had power to address concerns or purported abuse on either a complaint basis or by acting on its own initiative.

The government of the Northwest Territories ("GNWT") argued that the proposed merger would exacerbate concerns regarding jurisdictional regulatory uncertainty over the NGTL system as it would take on a more federal character if managed in common with TransCanada's system. The applicants acknowledged that there was no plan to pursue a change in regulatory jurisdiction of any of the regulated businesses or corporations involved in the merger, and since completion of the transactions would not change the nature or operations of the regulated businesses, there should not be any increased regulatory uncertainty. The EUB noted the view of the GNWT that application of the principles of the Supreme Court of Canada decision in *Westcoast Energy* v. *Canada (National Energy Board)* to the post-merger activities of the applicants would be difficult and add complexity to the jurisdictional argument. Absent other compelling reasons, however, the EUB concurred that it would be inappropriate to deny the application on the basis of speculative jurisdictional arguments.

The EUB accepted that the merger would not alter or adversely affect any service from any public or gas utility that is or may be owned, operated, managed, or controlled by the applicants or their affiliates and that the rights and liabilities of parties in relation thereto would not be adversely affected by the consummation of the merger. Accordingly, the EUB granted the necessary approvals for the merger and ordered that the transactions pursuant to the arrangement agreement would constitute a "union" pursuant to s. 99 of the *Public Utilities Board Act*.[193] The EUB further granted consent pursuant to paragraph 25.1(2)(d)(ii) of the *Gas Utilities Act*[194] and authorized NGTL to make the requested transfer of its shares to 747978 Alberta Ltd.

(vii) *Decision 99-1*[195] *and Addendum to Decision 99-1:*[196] *Applications by Gulf Canada Resources Limited and Nova Gas Transmission Ltd. to Construct and Operate a Sour Gas Processing Plant, Sour Natural Gas and Fuel Gas Pipelines and a Sweet Natural Gas Pipeline and Meter Station in the Steen River Area*

Gulf Canada Resources Limited ("Gulf") applied for an approval to construct and operate approximately eighteen kilometres of pipeline to gather sour natural gas from wells whose production would be processed at its proposed Steen River gas plant. NGTL also applied for an approval to construct and operate approximately fifty kilometres of a pipeline to transport sweet natural gas. Applications by Paramount Resources Ltd. and Bearspaw Petroleum Ltd. for a review and stay of an earlier approval of the Steen River gas plant, a motion to adjourn the hearing, as well as Gulf's application to dismiss the interveners' applications were all rejected by the EUB. The EUB considered the need for the plant, the gathering system and the associated sweet gas fuel lines, the need for the NGTL natural gas sales line and meter station, and safety and environmental considerations.

193 R.S.A. 1980, c. P-37.

194 *Supra* note 72.

195 *Gulf Canada Resources Limited Application to Construct and Operate a Sour Gas Processing Plant, Sour Natural Gas and Fuel Gas Pipeline; Steen River Area; Nova Gas Transmission Otd. Application to Construct and Operate a Sweet Natural Gas Pipeline and Meter Station; Steen River Area* (8 January 1999), 99-1 (A.E.U.B.).

196 *Gulf Canada Resources Limited Application to Construct and Operate a Sour Gas Processing Plant, Sour Natural Gas and Fuel Gas Pipeline; Steen River Area; Nova Gas Transmission Otd. Application to Construct and Operate a Sweet Natural Gas Pipeline and Meter Station; Steen River Area* (19 January 1999), 99-1 (A.E.U.B.).

The EUB was satisfied that Gulf had demonstrated that the Steen River area had both the gas reserves and deliverability to sustain the proposed plant and, in the absence of safety or environmental concerns, did not consider this to be a proliferation issue. Normal business decisions in a competitive marketplace dictated the need for the plant, and the EUB was prepared to accept that the sour gas gathering system and associated sweet gas fuel lines were integral components of the proposed processing plant.

(viii) *Decision D99-2: Shell Canada Limited Application to Construct and Operate an Oil Sands Mine in the Fort McMurray Area*[197]

Shell applied pursuant to s. 10 of the *Oil Sands Conservation Act* for approval to construct, operate, and reclaim the Muskeg River oil sands mine and associated bitumen extraction facilities in the Fort McMurray area. Approval was sought for a truck and shovel mining operation, a bitumen extraction plant, a bitumen froth treatment plant, and supporting utility infrastructure to produce approximately 8.7 million cubic metres of bitumen product per year or an average of 150,000 barrels per day.

The Athabasca Chipewyan First Nation ("ACFN") submitted that Shell's consultation with it was inadequate, since discussions had not resulted in Shell's firm commitment to provide employment and business contracts and that ACFN's concerns regarding the cumulative effects of the proposed oil sands development on traditional land uses had not been met. The ACFN argued that constitutionally, any *prima facie* infringement by Shell of its Treaty 8 and traditional rights on Lease 13 or adjacent lands could only be justified if there was meaningful consultation and compensation by the provincial government, or with the consent of ACFN and Shell. In the EUB's view, however, consultation need not result in the resolution of all or any objections. Only legitimate and well-intentioned efforts need be made toward that end. The EUB cited examples of what would amount to unsatisfactory consultation, such as "failure to communicate with all affected parties, misleading communications, inadequate project information, or discussions carried out in bad faith."[198] The EUB concluded that Shell made an adequate effort to explain the impacts of the Muskeg River mine with the various stakeholders and that the evidentiary or legal basis for the constitutional relief requested had not been established.

Since the EUB is charged with ensuring that conservation of resources occurs, the proper placement of surface discard and other similar sites was a key issue. The EUB accepted Shell's view that the proposed plant size was sufficiently large to accept the various planned and future developments, including a co-generation plant, but was not convinced that the outcomes and recommendations of the "Shell/Syncrude Lease Boundary Study" were appropriate. The EUB therefore required Shell and Syncrude to submit additional information to the EUB by 1 October 1999.

Although Shell did not apply to mine below the Muskeg River, the EUB was not confident that the proposed mine plan would not impact the ore under the Muskeg

197 (12 February 1999), 99-2 (A.E.U.B.).

198 *Ibid.*

River adjacent to the first pit, either due to the discard locations or the in-pit placement of consolidated tailings ("CT"). Shell was required to continue to evaluate its mine plans and report back on its findings two years prior to depositing CT into the first pit in order to ensure that the risk of negatively impacting future resource recovery near the Muskeg River was minimized.

The EUB expected Shell to meet its extraction recovery commitment of 92 percent within the first five years of operation. The EUB did not believe that the release of untreated froth treatment tailings and associated solvent directly to the tailings pond was acceptable and, therefore, requested Shell to identify alternative methods in order to reduce the risk of offsite impacts. Shell was required to report back to the EUB and the Department of Environmental Protection ("AEP") with the results of its analysis six months prior to plant construction.

With respect to developing a tailings management scheme, the EUB accepted Shell's CT strategy, but expected Shell, in conjunction with other oil sands operators, to continue to test alternative tailings technologies that reduce or eliminate the need for a conventional tailings pond. If such tests demonstrate the feasibility of alternative technologies, Shell's management scheme is to be re-evaluated. Shell is to provide a progress report to the EUB on its tailings research annually until commencement of operations, and then every second year thereafter.

With respect to environmental effects, the Oil Sands Environmental Coalition ("OSEC") considered the management of oxides of nitrogen ("NO_x") emissions to be a priority issue because of the role of NO_x in regional acid deposition and the generation of ground-level ozone. OSEC requested that conditions be added to the approval requiring Shell to conclude the memorandum of understanding ("MOU") process of setting emissions levels, not to initiate any construction until the MOU commitments had been honoured, and to comply with the predetermined emission levels of the MOU. Acid deposition was also noted by Environment Canada as a priority atmospheric issue. Its concern related to the potential impacts of the multiple oil sands projects and the need to work within environmental carrying capacity limits. The EUB accepted Shell's commitment to reduce its mine fleet emissions by 15 percent during the life of the project, but agreed with AEP and Alberta Health that continued research was necessary to better understand the effects of NO_x and ground-level ozone upon the environment and human health. The EUB supported Shell's commitment to convene a forum of technical experts and stakeholders to review the matter of ground-level ozone formation and accepted Shell's commitment to prepare a greenhouse gas management plan that includes emissions reduction targets for its Muskeg River mine. While the impact to air and water quality were deemed to be acceptable by the EUB in most cases, it believed that ongoing monitoring was required to ensure that predicted emission levels were met.

Without changes to the proposal, the EUB believed there was a reasonable risk that residents of Fort McKay might be affected by offsite odours due to emissions from Shell's tailings pond. As a result, the EUB expected Shell to specify, prior to commencement of operations, what mitigation strategies it would use to address the issue.

With respect to reclamation, Shell indicated that its interest in the mine would not be held in a separate limited liability company, but by Shell itself. Shell advised that it would set up an accrual account for the funds required for mine closure that would be sufficient to cover all the costs of reclamation and restoration. AEP stated that the *Conservation and Reclamation Regulation*[199] required the actual cost of reclamation to be provided as security. The EUB nonetheless accepted Shell's commitment to reclaim the affected area as proposed.

Many interveners made submissions in respect of the cumulative effects of oil sands developments, noting the multi-stakeholder process described by the Cumulative Environmental Effects Management Initiative ("CEEMI"), as well as AEP's "Sustainable Development Strategy." It was Environment Canada's view that the CEEMI was not yet in a position to be able to address the cumulative effects issue, nor was its relationship to operating approvals clearly understood. In addition, AEP indicated that the draft terms of reference for the Sustainable Development Strategy for the Athabasca oil sands region were currently before the public for review and comment and its report was targeted for July 1999. In response to the OSEC's request that the EUB conduct a public inquiry into the ecological carrying capacity of the region, the EUB expressed its belief that, as long as the various initiatives were making adequate progress, such an inquiry was unnecessary and reserved its decision for a s. 22 proceeding.

The EUB ultimately found the project to be in the public interest and approved the application, subject to Shell meeting the commitments and conditions outlined above.

(ix) *Decision D99-3: Matrix Resources Ltd. Application to Transfer Well Licenses*[200] *from Legacy Petroleum Ltd.*

Matrix Resources Ltd. ("Matrix") made applications pursuant to s. 18 of the *Oil and Gas Conservation Act* to transfer well licenses from Legacy Petroleum Ltd. ("Legacy") to Matrix and pursuant to s. 24 of the *Pipeline Act* to include the transfer of Legacy's pipeline licenses and related facilities to Matrix. In addition, pursuant to s. 43 of the *Energy Resources Conservation Act*,[201] Matrix requested that the EUB hear argument respecting closure order number C770, issued because Matrix (who operated but did not hold the well licenses for the subject wells), had no valid right to produce until the EUB consented or directed a transfer of such licenses.

At the outset of the hearing, KPMG presented the EUB with an *ex parte* order issued by the Court of Queen's Bench of Alberta [in bankruptcy], which ordered the assets of Legacy (including well licenses, pipeline licenses, and facilities) not to be transferred

199 Alta. Reg. 115/93.
200 (24 February 1999), 99-3 (A.E.U.B.).
201 R.S.A. 1980, c. E-11.

without the written approval of KPMG, trustee in bankruptcy of Legacy. The corporate compliance group of the EUB ("CCG") argued that the order constituted a material change, that transfer documents upon which the application was based were therefore void, and that the EUB could go no further with the hearing unless and until KPMG consented to the transfer. As the bankruptcy of Legacy also materially changed the application, the CCG believed the EUB must deny or dismiss the application. The CCG further asserted that the EUB should follow its standard procedure in the case of a bankrupt licensee and immediately issue abandonment orders to KPMG for the wells and facilities in issue in order to protect its position in the bankruptcy. CAPP and SEPAC made a joint submission supporting CCG's position, stating that protection of the industry abandonment fund was imperative and that the material change in circumstances would place the fund at risk if the EUB did not grant the requested relief. In response, Matrix explained that it was willing to take full responsibility for the abandonment and environmental liabilities associated with assets it purchased from Legacy. Matrix reasoned that the order only had the effect of temporarily restraining a transfer from occurring and that KPMG would have to prove to the court that the transfer of assets from Legacy to Matrix was invalid before the transaction between the two companies could be nullified.

The EUB agreed that the effect of the court order was to negate the validity of the original transfer documents executed by Legacy and Matrix in the absence of a written consent of KPMG. Because of the order, Legacy was no longer a party that could transfer the subject licenses and facilities. The EUB declined to exercise its discretion to direct a transfer on the basis that the court order caused the same conclusion. As a result, the EUB dismissed the application.

(x) *Decision D99-4: Imperial Oil Resources Limited of Industrial System Designation Cold Lake Expansion Project*[202]

Imperial Oil Resources Limited ("Imperial") requested the EUB to designate its new electrical generation, transmission, and distribution systems serving its Cold Lake operations as an "industrial system" pursuant to s. 2.2 of the *Hydro and Electric Energy Act*[203] and to make rules exempting from the operation of the *Electric Utilities Act*[204] the electric energy produced from and consumed by the proposed industrial system.

Pursuant to s. 2.2(3) of the *H&EEA*, the EUB may designate the whole or any part of an electric system as an industrial system if the EUB is satisfied that a number of criteria have been met. These criteria include location of a generating unit on the property of the industrial operations the electric system is intended to serve, a high degree of integration with one or more industrial operations the electric system serves, as well as a high degree of integration of the components of the industrial operations. In addition, the industrial operations should process a feed stock, or produce or

202 (4 March 1999), 99-4 (A.E.U.B.).
203 R.S.A. 1980, c. H-13 [hereinafter *H&EEA*].
204 S.A. 1995, c. E-5.5 [hereinafter *EUA*].

manufacture a primary product; there should be common ownership of all of the components of the industrial operations; the whole of the output of each component within such operation should be used by that operation; and there should be a high degree of integration of the management of the components and processes of the industrial operations. An application to the EUB for an industrial system designation should further demonstrate significant investments in both the expansion or extension of the industrial processes and the development of electricity supply. Where an industrial operation extends beyond contiguous property, the owner of the industrial operation should satisfy the EUB that the overall cost of providing distribution or transmission facilities to inter-connect the integral parts of the industrial operation is equal to or less than the tariffs applicable for distribution or transmission in the service area where it is located. If the EUB is not satisfied that such criteria have been met, it may nonetheless make an industrial system designation, provided that it is satisfied that such criteria have been substantially met and there is a significant and sustained increase in efficiency.

With respect to process integration, the EUB accepted that Imperial's operations at Cold Lake had a high degree of integration, notwithstanding the number of processing plants, because the product from such plants are co-mingled as the combined output from a continuous leased area. In addition, the pump station and brackish water wells were seen as an integral part of the operation and were to be considered part of the proposed industrial system. The EUB was also satisfied that the electric components of the AEC pipeline on Imperial's site could be treated as components of Imperial's proposed industrial system despite its ownership by AEC.

With respect to transmission cost reallocation, Imperial argued that the industrial system designation was designed to ensure that it would not result in undue transfer of costs. Alberta Power Limited ("APL") contested Imperial's prediction that its proposed co-generation plant would, under all operating conditions, cause a reduction in transmission losses and could unilaterally lower the spot market price of electric energy in Alberta. Enmax stated that the government policy on industrial system designation and the *EUA* did not explicitly mention "undue cost allocation," although it noted that the *H&EEA* was amended to reflect the objectives of giving appropriate economic signals. The EUB believed that the proposed industrial system designation supports the development of power generation to meet Imperial's requirement of its industrial process at Cold Lake and agreed that such designation would facilitate development of new power generation and offer cost effective energy in excess of Imperial's requirements to the inter-connected electric system. The EUB recognized that, in granting any industrial systems designations, appropriate economic signals could be given to other integrated applications to develop their own internal supply of electricity. Notwithstanding the benefits, the EUB recognized that, as new industrial system designations are implemented, it will involve some implied reallocation of transmission costs which the proponents of such systems were expected to absorb proportionately in a re-configuration of the transmission network.

The EUB agreed that definite boundaries should be established when granting an industrial system designation and in that context indicated it would accept the designation to apply to the regulated lease boundary of the Cold Lake project, which entailed all facilities that were for the exclusive production and disposition of bitumen and other products at that site.

With respect to sharing of transmission facilities, Imperial pointed out that there was a provision in the *H&EEA* that allowed the EUB to require any owner of transmission facilities to share the use of such facilities with other users. The EUB noted that transmission facilities within a designated industry system are not exempt from such provisions and therefore believed there was no need to condition the industrial system approval to provide access to those facilities by other potential users. The EUB also concurred that industrial systems were not exempt from present or future applicable tariffs and expected the transmission administrator to deal with this issue when Imperial applied to inter-connect with the system. In conclusion, the EUB was satisfied that Imperial's proposal met the requirements of s. 2.2 of the *H&EEA* and believed that it would be in the public interest to exempt the electric energy produced from and consumed by the applied-for industrial system from the operation of the *EUA*.

(xi) *Decision D99-7: Application by Suncor Energy Inc. for Amendment of Approval No. 8101 for the Proposed Project Millennium Development*[205]

Suncor Energy Inc. ("Suncor") applied pursuant to s. 14 of the *Oil Sands Conservation Act* to amend approval number 8101 in respect of its existing oil sands mine and processing facilities in its "Project Millennium" in the Fort McMurray area. The proposed development was to increase production capacity to a minimum level of 210,000 barrels per day of crude oil products by 2002 and included an expansion to the Steepbank mine, an oil sands extraction plant on the east side of the Athabasca River, modifications to the current oil sands extraction plant on the west side of the Athabasca River, an addition of the second processing train to upgrade oil sands products, utilities, and other infrastructure associated with the mine and processing unit, and an integrated reclamation plan for all of Suncor's mining areas.

Suncor would continue to use a tailings pond for initial tailings storage with conversion to consolidated technology until in-pit storage became available and an end-pit lake would remain following completion of the mining. As 1 April 1999, was a critical date for Suncor with respect to construction activities, it required a timely decision. The EUB approved Suncor's application, indicating it would issue the required approval in due course together with the detailed report giving the reasons for its decision, noting that Suncor has accepted the risk with respect to any conditions that could be attached to the EUB's approval.

[205] (29 March 1999), 99-07 (A.E.U.B.).

(xii) *Decision 99-8: Shell Canada Limited Application to Construct and Operate an Oil Sands Bitumen Upgrader in the Fort Saskatchewan Area; Shell Canada Products Limited Application to Amend Refinery Approval in the Fort Saskatchewan Area*[206]

Pursuant to s. 11 of the *Oil Sands Conservation Act*, Shell applied for approval to construct and operate an oil sands bitumen upgrader adjoining its existing Scotford refinery to principally process bitumen from Shell's proposed Muskeg mine. Pursuant to s. 13 of the *Oil Sands Conservation Act*, Shell also applied for an amendment to the existing Scotford refinery approval for the processing of 3.7 million cubic metres per year of sour conversion feed stock.

While no concerns were expressed respecting the need for the upgrader or modifications to the existing Scotford refinery, the EUB considered technology selection, air-health, sulphur recovery, noise, and traffic and land use conflict issues.

Shell proposed to locate its upgrader north of and adjacent to its existing Scotford refinery and argued that its hydrocracking capacity would enable it to use hydroconversion technology. The EUB accepted Shell's choice of upgrading technology as offering material improvements in environmental performance and liquid hydrocarbon yield relative to other technologies.

Despite complaints by residents that ambient air quality guidelines for SO_2 were already being exceeded in the area, both AEP and Alberta's Department of Health did not believe that the upgrader would have a significant impact on either the number of ambient air quality exceedances or on human health. The EUB accepted Shell's information that emissions from the upgrader would not significantly impact existing ambient air quality, but believed a coordinated monitoring approach by all stakeholders would be more productive than independent programs mandated by approvals on individual industrial operators. The EUB agreed to work with AEP, municipal officials, and industrial operators to arrange for a coordinated, regional air monitoring program.

Shell requested that the upgrader be approved to meet a 98 percent quarterly sulphur recovery level and a daily maximum SO_2 emission based on 95 percent recovery. The EUB agreed that project approvals should permit a reasonable level of flexibility in sulphur recovery during the commissioning stage of the project to accommodate a start-up period which, in this case, was determined to be two years from start-up and accordingly concluded that 98.5 percent quarterly and 98.8 percent annual average sulphur recoveries would be appropriate.

Residents requested that they be relocated and their properties purchased in order to resolve a land use conflict issue. In noting that efforts to date had failed to address residents' concerns in this area, the EUB urged all parties to continue to work toward an early resolution believing, however, that full industrial development of the area was ultimately not acceptable without relocation of the residents. Although the EUB had no

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206 (6 April 1999), 99-8 (A.E.U.B.).

jurisdiction in the process to effect settlement, it indicated that it may not be able to approve any additional projects in the area in the future that would create significant incremental impacts to the residents until the issue had been resolved. In making its decision, the EUB noted it was influenced by the fact that the upgrader was proposed to be located north of the existing refinery, further from the residents, and that amendments to the refinery did not involve a new site. In its conclusion, the EUB found the projects to be in the public interest and approved the Scotford upgrader and refinery modifications.

(xiii) *Decision U99032: The Small Explorers and Producers Association of Canada (SEPAC) Application for Review and Variance of the Board Decision U96001*[207]

In this decision the EUB ruled on the application by SEPAC for review and variance of a decision[208] in which the EUB approved the revenue requirement for NGTL for 1995, including the costs associated with the contract that provided NGTL with firm service capacity of 540 million cubic feet per day on Foothills "Zone 7" facilities.

Section 56 of the *Public Utilities Board Act* provides that the EUB may review, rescind, or vary any order or decision made by it. Discretion to review should, in the EUB's opinion, be exercised sparingly. Although statutory guidelines as to when such discretion may be exercised do not exist, the EUB restated that certain matters might be taken into account as follows:

(1) where new evidence, which was neither known, nor available at the time evidence was adduced, and which may have been a determining factor in the decision, becomes known after the decision was made;

(2) where a decision is based on an error of law or fact, if such error is either obvious or is shown on a balance of probabilities to exist, and if correction of such error would materially affect the decision;

(3) where correction of a clerical error or a clarification of ambiguity is required; or

(4) where other criteria, particular to a given case, are shown to be valid.[209]

The application set out three grounds for review which alleged that the EUB erred in jurisdiction and in law:[210]

(1) by approving a 1995 revenue requirement for NGTL which will result in rates that are not just and reasonable, contrary to paragraph 28(a) of the *Gas*

207 (April 1999), U99032 (A.E.U.B.).
208 (4 January 1996), U96001 (A.E.U.B.) [hereinafter U96001].
209 *Supra* note 207 at 2.
210 *Ibid.* at 3.

Utilities Act and that the EUB allowed costs of the contract which in a prior decision had been determined as not prudently entered into;

(2) by making a determination as to the prudence of costs of a contract in an unfair and unreasonable manner and in a manner that appears to circumvent the process and procedures established by the EUB to deal with issues pending before it respecting the prudence of the same contract; and

(3) by failing to give any or adequate reasons for its decision, contrary to s. 7 of the *Administrative Procedures Act*.[211]

The EUB noted that different circumstances were addressed in decision U96001 than in decision E95079.[212] Although the EUB had subsequently determined that there were reasonable grounds to review decision E95079, a review did not occur due to a negotiated settlement between the parties. By contrast, decision E96001 represented the first ruling on NGTL's tolls and tariffs as a utility fully regulated by the EUB. Due to changed circumstances, the EUB said there was no obvious inconsistency or "reversal," in that decisions E95079 and U96001 treated contract costs differently in different years. The EUB therefore dismissed SEPAC's first ground for review.

The EUB was further satisfied that all interested parties had sufficient opportunity to deal with the issues raised in the proceeding leading to decision U96001 and that it did not utilize an unfair or unreasonable process. In such proceeding, the EUB heard evidence and argument regarding 1995 circumstances and differences from the 1993 and 1994 set of circumstances. As a result, the EUB dismissed SEPAC's second ground for review.

With respect to the third ground, SEPAC alleged errors of jurisdiction in law in that decision U96001 did not disclose the EUB's reasons for accepting, and therefore implicitly determined that, the "transportation by others" charges incurred by NGTL pursuant to the contract were prudent and would result in just and reasonable rates commencing in 1995. The EUB's reasons for its findings in decision U96001 were summarized as follows:

(1) The Foothills "Zone 7" facilities consisted of loops on the NGTL system and formed an integral part of NGTL from an operational perspective. The EUB believed that shippers utilizing the integrated system under similar terms and conditions and representing a large cross-section of the producing industry should be treated equally.

(2) With respect to the alleged duplicate costs in Foothills tolls, this matter was more properly dealt with by the NEB, which regulates Foothills. The EUB

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211 R.S.A. 1980, c. A-2.

212 (28 July 1995), E95079 (E.R.C.B.) [hereinafter E95079].

accepted the principle of regulatory comity and would not normally substitute its judgment for that of other regulators.[213]

The EUB considered that such reasons represented sufficient and adequate grounds for its findings and that the issue of prudence of the 1993 and 1994 contract costs was therefore irrelevant for 1995 once NGTL's revenue requirement included all of Foothills "Zone 7" costs. The EUB consequently dismissed SEPAC's third ground for review. As a result, SEPAC's request for review and variance of decision U96001 was denied.

b. Recommendations of the EUB Examiners

(i) *Examiner Report 98-3: Application for a Well License by Ulster Petroleums Ltd. in the Three Hills Creek Field*[214]

Ulster Petroleums Ltd. ("Ulster") applied to the EUB for a well license to drill a vertical sour oil well. Objections were filed by adjacent residents south of the proposed well location, citing concerns related to the aesthetic impacts of the visibility and noise of the wells and safety concerns associated with H_2S gas.

The examiners accepted the surface location put forth by Ulster and believed that the measures committed to by Ulster would mitigate the impact of the proposed well. In addition, moving the well site 250 metres to the west would not provide measurable benefit from a surface impact point of view. Nonetheless, the examiners recommended that the well license be denied given the larger H_2S release rates calculated since the original application and the fact that Ulster did not contact residents or landowners beyond a one-kilometre radius of the well, when the examiners believed the resulting emergency planning zone was 2.9 kilometres.

It was also noted that the surface lease for the applied-for well had been prepared without a well license. Ulster argued that, although s. 11 of the *Oil and Gas Conservation Act* prohibits this type of activity, Informational Letter 90-20,[215] in an attempt to address this practice, had created some ambiguity. The examiners nevertheless believed that pre-license preparation of a well site prior to ensuring there were no objections from adjacent landowners and occupants was unacceptable. The examiners accepted Ulster's commitment to ensure the preparation of these sites, prior to obtaining a well license approval, would not happen again.

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213 *Supra* note 208 at 6.

214 *Application for a Well License; Three Hills Creek Field; Ulster Petroleums Ltd.*, LSD 8-17-36-26 W4M (26 May 1998), 98-3 (A.E.U.B.).

215 "Well Site and Access Road Construction Prior to the Issuance of a Well License" (23 November 1990).

(ii) *Examiner Report 98-8: Loon Energy Inc. Application for a Well License in the Carvel Field*[216]

Loon Energy Inc. ("Loon") applied to the EUB for a well license to drill a directional sweet gas well located near Lakewood Estates, a country residential subdivision just north of the proposed location.

The examiners commented on the public consultation program carried out by Loon, noting room for improvement in respect of notification procedures and follow-up issues management. The examiners concurred with the intervener that there was an undue reliance on the community association of representatives to notify residents of Lakewood Estates and that communication may have been enhanced with a formal open house, advertised in the community, with technical experts available to explain the project to the public. The examiners concluded that both the applied-for location and the alternate location were acceptable, although the alternate location was preferable, and recommended approval of Loon's well license application at the alternate location, subject to confirmation of landowner consent, the submission of a revised survey plan, and honouring commitments made to area residents.

(iii) *Examiner Report 98-9: Amoco Canada Petroleum Company Ltd. Application for a Pipeline in the Pembina Field*[217]

In this application by Amoco Canada Petroleum Company Ltd. ("Amoco") to construct a pipeline to transport sweet natural gas to a tie-in point, objections were received from an adjacent landowner to the proposed pipeline route, citing plans to develop the aggregate for making concrete that provided his livelihood. The examiners considered the need for and the appropriateness of a pipeline and the impact the routing of a pipeline could have on a potential future gravel extraction operation.

A well had been drilled on the lands in question in 1959 and suspended due to lack of infrastructure. Amoco stated that the pipeline was required to produce the well and transport the product to market. The landowner planned to start extracting gravel from the river continuing north to the property line and argued that any pipeline along the riverbank would impact upon his ability to extract gravel, store top soil and subsoil, and access the riverbank. The examiners took the view that the Alberta Department of Environmental Protection ("AEP") could impose a thirty-metre setback from the riverbank on any gravel extraction operation and that the routing of the pipeline within that setback would minimize the impact of the pipeline on gravel extraction. If such setback was not required and it was subsequently found that the pipeline affected the intervener's ability to extract gravel, the examiners indicated that arbitration could be dealt with by the Surface Rights Board and accordingly recommended that the pipeline permit be issued.

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216 (30 November 1998), 98-8 (A.E.U.B.).

217 (25 November 1998), 98-9 (A.E.U.B.).

(iv) *Examiner Report 98-10: Magin Energy Inc. Application for a Pipeline Permit*[218]

Magin Energy Inc. ("Magin") applied for a permit to construct and operate approximately 500 metres of fiberglass pipeline to transport effluent from a well to a tie-in point. Landowners of the affected pipeline route expressed concern over past operating practices and objected to the approval of an additional pipeline until problems regarding soil erosion, reclamation of past spills, and integrity of existing pipelines on the property were addressed. The proposed route of the pipeline was not in issue.

The examiners expressed concern about the fact that the EUB records indicated that there had not been any breaks on the tie-in line, yet the interveners identified four occurrences of pipeline breaks along routes constructed by the prior owner of the pipeline. These examiners further noted that Magin's testimony brought into question its understanding of what suitable construction and reclamation practices were for the environment in which it wished to construct the proposed pipeline. The examiners understood that industry often retained environmental consultants to address environmental requirements of proposed developments but specified that it remained the responsibility of a proponent to be familiar with the environmental requirements it was required to follow, and to ensure that its proposed development would have minimal impact on the environment and surface landowner. The examiners therefore recommended that Magin prepare a site-specific environmental protection plan to document what methods were to be used for soil handling, erosion control, and re-vegetation and recommended approval of the application subject thereto.

(v) *Examiner Report 99-1: Bonavista Petroleum Ltd., Pacific Cassiar Limited Compulsory Pooling and Pipelines in the Blood and Magrath Areas*[219]

Pinnacle Resources Ltd. ("Pinnacle") submitted an application for a compulsory pooling order as well as two applications for the construction of separate sweet natural gas pipelines. Pacific Cassiar Limited ("Pacific") submitted an application requesting approval for the construction of a sweet natural gas pipeline. Pinnacle opposed Pacific's application and Pacific opposed all three of Pinnacle's applications. Wilde Brothers Farms Ltd. opposed Pinnacle's two pipeline applications and PanCanadian Petroleum Limited and Knight Development Company Limited, freehold mineral owners of the proposed pooled section, supported the application for a compulsory pooling order.

Bonavista Petroleum Ltd. ("Bonavista") appeared at the commencement of a hearing to speak to the applications previously submitted by Pinnacle and continued by Renaissance Energy Ltd. ("Renaissance"), advising that it had adopted the applications and other submissions filed by Pinnacle. Bonavista filed documents showing the transfer of petroleum and natural gas leases involved in the application from Renaissance, who had earlier amalgamated with Pinnacle, as well as an application transferring the well licenses from Renaissance to Bonavista. Despite objections by

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218 (1 December 1998), 98-10 (A.E.U.B.).

219 (26 January 1999), 99-1 (A.E.U.B.).

Pacific that Bonavista appeared as a stranger to the proceedings and the examiners' disappointment that Bonavista choose not to contact the EUB and the parties involved in the matter before the hearing, Bonavista was granted the necessary standing in order to proceed.

Pacific opposed the issuance of the pooling order on the basis of a misrepresentation in the application for the license which, it argued, meant that the well was improperly drilled. It noted that the application for the license showed the well as a development well for the purpose of obtaining Taber oil from the proposed depth, but that the license would not in fact be deep enough to encounter the Taber zone. Pacific nonetheless submitted that if a pooling order was issued, drilling and completion costs to be shared by tract owners should be discounted by 50 percent because the Taber target zone was below the pooled Bow Island zone. The examiners noted that it was not unique that well licenses had target zones which subsequently would not be encountered and were unable to conclude that there was any misrepresentation on the well license application or any other associated motive with it. The examiners noted the inability of the parties to reach a voluntary pooling arrangement and concluded that a pooling order was needed to allow Bonavista to produce the reserves.

With respect to the basis for allocation of costs and revenues under a pooling order, examiners noted that paragraph 72(4)(b) of the *Oil and Gas Conservation Act* stated that such allocation "shall be on an area basis unless it can be shown to the Board that this basis is inequitable." The three different interpretations presented were indicative, in the examiners' view, that mapping within the section was highly interpretive and, as a result, could not be used as a basis for allocation. Allocation was therefore awarded on a tract area basis.

The actual costs of drilling the well to its total depth and completing it in the formation to be pooled were, in the examiners' belief, properly shared under a pooling order. The well was not drilled beyond the productive zone to such an extent as to justify discounting the well costs as requested by Pacific. The examiners further believed that the order should provide for the maximum penalty allowed, as it was standard practice in cases where there is an industry dispute for pooling orders to include a provision that the maximum penalty allowed under the *Oil and Gas Conservation Act* be applied if well costs are not paid within the specified time.

The examiners accepted that the competitive nature of pooled development in the area would make it undesirable to delay producing the well pending the uncertain possibility that Pacific might some day install additional capacity in its existing facilities for gas produced from the well. On that basis, the examiners were satisfied that there was a need for the pipeline and stated that owners of existing facilities who were prepared to accept gas from other parties had an obligation to come forward with proposals or offers respecting the use of facilities when they become aware of proposals for new facilities. The examiners then recommended approval of each of the pipeline applications.

c. Applications

(i) *Application by Nova Gas Transmission Ltd. Re 1999 Products and Pricing*[220]

On 6 April 1999, NGTL filed an application with the EUB requesting approval for a new rate design and terms and conditions of service for gas transportation within Alberta that departed significantly from the current "postage stamp" rate in place since 1980. The application represented the culmination of two years of extensive discussions with industry, as well as the revolutionary accord reached in April 1998 among CAPP, SEPAC, TransCanada, NOVA, and NGTL for a new receipt-point pricing structure and settlement proposal for gas transportation tolls on NGTL's system. If approved, the proposal would be phased in over four years, with a requested implementation date of the first day of the month which is eight weeks after EUB approval is granted.

Under NGTL's proposed receipt-point pricing structure, customers were to pay a minimum of the average firm receipt service price ("AFRSP") less $0.08 per thousand cubic feet (*i.e.* $0.18) and a maximum of the AFRSP plus $0.08 per thousand cubic feet (*i.e.* $0.34), depending upon the receipt point to which they were contracted. By comparison, the "postage stamp" rate was approximately twenty-six cents per thousand cubic feet. The new rate design introduced rates for receipt service that reflected costs attributable to the relative diameter of pipe and the distance from each receipt point to the major border delivery points, although the practice of treating receipt and delivery rates separately continued, leaving the delivery rate calculation methodology unchanged. To permit NGTL to compete fairly with third party proposals to provide incremental transportation capacity of at least 400 million cubic feet per day, during periods when the price floor and ceiling were in effect, NGTL proposed that it be allowed to negotiate a price adjustment with CAPP, who, in the case of agreement, would support the consequential application to the EUB. If the parties failed to reach such agreement, either party would be free to apply to the EUB for a change in price or rate design.

Under the existing rate structure, all firm service contract prices were independent of length of contract with no term-linked tolls. In this application, NGTL proposed term-differentiated tolling and incentives for providing increased renewal notice periods. For example, firm service receipt contract terms of one, three, and five years were proposed to be priced at a 5 percent premium for one year, 0 percent for three years, and a 5 percent discount for a five-year contract. NGTL also proposed that it be allowed to develop new services that were incremental to existing services and that the revenues and full cost of providing such services would be for NGTL's account and therefore excluded from the total revenue requirement. The proposal was also said to preserve NGTL's gas trading and inventory exchange capabilities.

NGTL also proposed two other significant changes: (1) that its revenue requirement continue to be defined by the cost efficiency incentive settlement agreement ("CEIS"), but that the resulting total revenue requirement be adjusted by NGTL's contribution to

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220 *Re an Application to the Alberta Energy and Utilities Board by NOVA Gas Transmission Ltd. Re 1999 Products and Pricing* (6 April 1999), 990157 (A.E.U.B.).

transition costs over a two-year period and by revenue variations, (subject to a collar around the amount of revenue shortfall or gain to which NGTL's shareholders were exposed); and (2) following a short transition period, NGTL would no longer construct or include in its rate base new customer-specific Alberta receipt and delivery facilities (other than meter stations and tie-ins) as part of its regulated business. In NGTL's view, these changes reflected stakeholders' joint desires to mitigate the impact of transition to a new rate design and for increased cost accountability, customer choice, and a more competitive environment.

The rate change was also mitigated during the transition period through proposed monetary contributions by both NGTL and its customers. NGTL agreed to contribute $20 million pre-tax per year for two years, while shippers were to contribute $20 million pre-tax per year for two years from CEIS savings. These contributions were believed to cushion the impact on customers of the revenue shortfall caused by rates rising to the price ceiling slower than rates falling to the price floor over the transition period.[221] NGTL also requested the ability to roll in the cost of any stranded investment for the first five years after the in-service date of the Alliance pipeline project.

The "postage stamp" rate design has been the subject of several complaint proceedings, including NGTL's 1995 general rate application[222] and NGTL's application for a load retention rate in response to a bypass threat from the proposed Palliser pipeline project. The load retention rate was approved in decision U97096[223] and industry participants have, in general, endorsed NGTL's new pricing structure.

(ii) *Application by AEC West re Declaration of Common Carrier in the Leming Field*[224]

Although this application was withdrawn prior to commencement of the hearing, AEC West had also applied pursuant to s. 42 of the *Oil and Gas Conservation Act* for an order declaring Amoco as a common processor of gas produced from the O pool through the Amoco Wolf Lake facility. The EUB denied this portion of the application on the basis that it did not have the jurisdiction to issue a common processor order respecting a facility that was not a processing plant as defined by paragraph 1(1)(q.1) of the Act.[225]

221 *Ibid.* at 22.

222 *Re Nova Gas Transmission Ltd. General Rate Application* (21 June 1996), U96055 (A.E.U.B.).

223 *NOVA Gas Transmission Ltd. Load Retention Service* (14 November 1997), U97096 (A.E.U.B.).

224 *Re an Application to the Alberta Energy and Utilities Board by AEC West requesting a Declaration of Common Carrier in the Leming Field* (6 March 1998), 1022074 (A.E.U.B.).

225 Notice of Hearing re Application No. 1022074 (16 March 1999), (A.E.U.B.).

(iii) *Gulf Canada Resources Limited — Application to Shut-In Associated Gas Production in Surmont Area*[226]

The jurisdiction of the EUB was at issue in an application by Gulf heard on 20 April 1999, requesting, among other things, the long-term shut-in of associated gas production from the Wabiskaw-McMurray formation on and surrounding Gulf's Surmont oil sands leases until oil sands development was completed. Gulf provided evidence to support its argument that continued production of associated gas on its Surmont oil sands leases had had, and continued to have, a detrimental impact on bitumen recovery and would reduce reservoir pressure to the point of rendering a development of the Surmont oil sands deposits uneconomic. Natural gas in the Wabiskaw-McMurray formation in the Surmont area was in pressure communication with the bitumen directly or through the water zone between the natural gas and the bitumen, and if gas production was allowed to continue, Gulf believed that the natural pressure support from the aquifer was expected to provide very limited repressuring of the Surmont area within a time frame adequate for commercial bitumen production. Gulf indicated it would not proceed with the filing of its commercial application for the development of the Surmont oil sands leases until it knew that unrestricted associated gas production would not be allowed. Gulf also requested that any further drilling for natural gas from the affected formation on the Surmont oil sands leases be prohibited until bitumen recovery was complete, and that the EUB establish a procedure to allow the review of wells with confidential status during the hearing. On Gulf's analysis, there were between approximately 95 to 105 billion cubic feet of remaining producible natural gas reserves and approximately fifteen billion barrels of in-place bitumen suitable for commercial development in pressure communication across the Surmont area. The recoverable bitumen was said to support development of at least ten to fifteen different projects, each capable of 25,000 barrels per day for thirty years.

Gulf also took the view that it was not a simple task of repressuring a single isolated natural gas pool with natural gas, recovering the bitumen and then moving that natural gas to repressure the next pool to allow further bitumen recovery. An entire region of influence would need to be repressured for a successful operation. Since approximately 179 billion cubic feet of natural gas had been produced to date, the cost of purchasing the same volume for re-injection was prohibitive in Gulf's view, even ignoring the associated capital and operating costs that would be required. Furthermore, greater social benefits from the priority production of bitumen existed, in Gulf's view, even with the long-term shut-in of gas.

In its submission dated 2 March 1999, the Surmont Producers Group ("SPG") characterized the issue as one of expropriation of property rights that would cause significant damage to Alberta's reputation as an investment location and challenged the EUB's jurisdiction on the matter. SPG contended that the requested shut-in term was "unspecified and indefinite" and that this would constitute a permanent prohibition on

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226 *Re an Application by Gulf Canada Resources Limited for an Order Requesting the Associated Gas Production from the Wabiskaw-McMurray Formation on and Surrounding its Surmont Oil Sands Leases be Shut-In* (15 June 1998), 960952 (A.E.U.B.).

the production of gas, thereby depriving it of the economic value of its properties. SPG argued that the production of overlying gas pools caused no physical change to bitumen deposits and that solution gas remains in the bitumen at pressures as low as zero kilopascals. In addition, SPG suggested that pressure in the gas pools could be lowered to abandonment pressure without adversely affecting the reservoir and that the gas pools were originally under-pressured and not in any way contributing to the support of the overburden. In its view, repressuring could safely be accomplished without fracturing the McMurray formation and reducing gas pressure would move the state of stress in the McMurray into the stable realm.

Since Gulf's initial filing, the EUB held a public inquiry and determined that it has the jurisdiction to hear and decide Gulf's application. Following the public inquiry, Gulf provided a rebuttal dated 8 March 1999, to SPG's submissions, noting that it was contrary to the public interest to risk the loss of the vast bitumen resources on such leases to recover the few remaining BCF of natural gas. In addition, Gulf suggested that, as the natural gas had been substantially produced, SPG had had the benefit of their investment in this area while Gulf's investment and any return is at risk. Gulf took issue with SPG's central technical argument that the gas pools were small and isolated, and indicated that a significant number of the wells were in direct pressure communication with commercially exploitable bitumen. With respect to SPG's contention that Gulf's application constituted expropriation without compensation, Gulf noted that all holders of oil and gas interests in Alberta were subject to the EUB's over-arching conservation mandate. Gulf also took issue with SPG's suggestion that natural gas and bitumen were mutually exclusive when in fact neither resource existed independently of the other in this area, in their view. Gulf also took issue with SPG's argument that slowing the drainage process could be offset by drilling longer wells and producing them for a longer period of time, as Gulf's simulations did not bring the recovery factor up to that recoverable at higher pressures.

d. Informational Letters

(i) *Informational Letter IL 98-04, "Negotiated Settlement Guidelines; Tolls, Tariffs and Terms and Conditions of Service"*[227]

These guidelines outline the EUB's expectations and serve to assist participants in respect of the negotiated settlement process. The EUB's expectations are based on the following key principles:

(1) parties involved in the process will participate in good faith;

(2) the negotiated settlement process must be (a) open and fair to all interested parties; (b) conducted on a confidential, without-prejudice basis; and (c) sufficiently flexible to accommodate unique circumstances and requirements; and

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[227] (15 May 1998).

(3) sufficient information must be available at the outset and during the course of the settlement process to facilitate understanding and review of the issues being negotiated.[228]

Each utility may develop its settlement process in the manner most appropriate for its circumstances, provided that the process is clearly understood and agreed upon by all parties at the outset. Parties will have the right to seek direction from the EUB and must be given the opportunity to participate fully, although such participation is voluntary. Information provided during the process should be available to all parties having an interest in the issues. The EUB will require confirmation that proper notice was provided by the applicant to all interested parties.

As one of the initial steps in initiating the process, parties are to determine the issues and may seek direction from the EUB in the event there is any doubt. The process is expected to be initiated generally prior to filing an application to the EUB. Representatives at a negotiated settlement process must have authority to settle issues on behalf of a party and to enter into the settlement agreement. Any limitations on such authority must be disclosed at the outset of the process. Settlement negotiations and any record thereof will not be part of the public record unless agreed to by the parties, and the parties are to determine what information is to be treated confidentially.

The EUB may serve to mediate the settlement provided that the members thereof do not participate in deliberations by the EUB arising from any issue without the express consent of the parties. The EUB staff will generally not participate in the negotiated settlement process. Mediators may be selected but shall not be witnesses at a hearing nor shall they be required to provide opinions or reports on the settlement. Costs of mediators will be part of the overall costs of the application and subject to the EUB's order.

When an agreement is reached, an application that includes a copy of the settlement agreement and describes any outstanding issue shall be filed with the EUB which then becomes binding on all parties who have agreed to it. At a minimum, the following information is expected to be included in support of an application: evidence of adequate notice; the settlement agreement; details of issues not resolved; outline of issues where acceptance is not unanimous including the names of those who disagree; and the rates that result from the settlement, supported by schedules, to assist the EUB in understanding how rates were derived.

Prior to approval of the settlement by the EUB, a party may withdraw its acceptance or support if evidence is introduced that affects the terms or conditions of the agreement. Withdrawing parties must give notice to the EUB and to other parties of their intention to withdraw and the reasons.

With respect to evaluating and accepting a settlement agreement, the EUB indicated that it will not approve part of a settlement agreement if the parties have negotiated on

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[228] *Ibid.* at 2.

the basis that the agreement is contingent on the EUB's accepting the entire agreement. If the EUB rejects an agreement that has been negotiated as a package, it will indicate those parts of the agreement that cause concern and cannot be accepted by the EUB including the reasons therefor. Parties may then be provided with an opportunity to renegotiate and attempt to resolve the outstanding issues. Reasonable efforts are expected to be made to revise the settlement agreement. A revised application addressing such outstanding issues may then be filed with the EUB although if parties are unable to resolve the issues, any subsequent application will be considered through the EUB's hearing process.

In determining acceptability of a settlement agreement, the EUB will address any deviation from existing law and policies and will consider whether the agreement is in the public interest, is reasonable and fair to all interested parties, has a well sustained rational basis, and is complete and adequate to support the application.

The EUB will determine the process for dealing with issues identified by non-participants or parties with dissenting views and such views will be considered if a hearing is determined as not being required. If significant new evidence or information emerges subsequent to the EUB's approval, it may reconsider its approval of the agreement and any review for variance will be conducted in accordance with the legislation that the EUB administers. Parties are encouraged to reach agreement on costs incurred in the process and the manner in which such costs will be paid. Details of such agreements may be included in the settlement agreement with a request that they be incorporated into the EUB's final order. Alternatively, payment of costs may be finalized among the parties and a summary filed with the EUB. Where parties are unable to agree on costs, the EUB may determine the manner of payment pursuant to its cost rules.

(ii) *Informational Letter IL 98-5: Addendum to Attachment to IL 90-8 Respecting Procedures for the Assessment of NOVA Pipeline Applications*[229]

The EUB granted GTL's request to change the submission date of its annual plan from May of each year to December 15th. The change enables GTL to more appropriately align its annual plan process with the firm service design process as well as other internal business and budgeting processes.

(iii) *Informational Letter IL 98-6, "Stress Corrosion Cracking on Pipelines"*[230]

All pipeline licensees are now expected to evaluate the extent of stress corrosion cracking on their pipelines, to take appropriate measures to deal with it, and to collect relevant data. Prior to the end of April 1999, licensees are expected to submit their data to the Canadian Energy Pipeline Association or CAPP, which are developing and will maintain databases on the results of such field investigations. By the end of June 1999,

229 "Addendum to Attachment to Informational Letter IL 90-8 Procedures for the Assessment of NOVA Pipeline Applications — Industry Review" (28 May 1998).

230 (29 May 1998).

industry associations are to submit a report evaluating the results of their field investigations. Such information will be used to determine what, if any, further steps are necessary to deal with stress corrosion cracking in Alberta.

(iv) *Informational Letter IL 98-07, "Responsibility for Y2K Preparation"*[231]

The purpose of this letter was to notify all licensees, operators, and utilities about their obligation to maintain safe and efficient facility operations before, during, and after the year 2000 ("Y2K") changeover. In addition to a company's specific needs, the EUB recommended each Y2K program include the following:

(1) identification and inventory of all systems and operations affected by the Y2K transition;

(2) assessment of the potential impact of Y2K on the safe, efficient, and reliable operation of facilities, related installations, systems, and operations;

(3) a plan for testing systems and operations before, during, and after the year 2000; and

(4) outline of contingency plans for possible failures and upsets because of Y2K.[232]

If companies fail to comply, the EUB will use its normal escalating enforcement process, and it notified industry that it may audit Y2K programs starting 15 November 1998.

e. General Bulletins

(i) *General Bulletin 98-07, "Electronic Transmission and Capture of Well Test Data"*[233]

In this bulletin, the EUB announced its objective to be in a position to receive well test data electronically by 1 July 1998, on a voluntary trial basis until 31 December 1998. Effective 1 January 1999, the EUB required well test data to be transmitted electronically.

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[231] (29 September 1998).

[232] *Ibid.* at 1.

[233] (1 May 1998).

(ii) *General Bulletin 98-12, "1998 Abandonment Fund Levy"*[234]

The 1998 annual abandonment fund levy was set at $100 per inactive well. Licensees of record as at 31 December 1997, were responsible for payment, which was required no later than 4 September 1998. No grace periods for late payments were allowed and a 25 percent penalty was imposed for failure to pay on time. Appeals of such levies were to be received by 31 July 1998. Appeals were not to be granted when a well had been transferred, abandoned or placed on production after 31 December 1997, or placed on production for testing purposes only. The levy excludes training wells, observation wells, and wells that are an integral part of the storage scheme, domestic wells, or wells whose purpose is outside the petroleum industry.

(iii) *General Bulletin 98-13, "Minimum Standards for Flare Tanks"*[235]

This bulletin outlined the recommended minimum standards for flare tanks as developed by the "Industry-Government Drilling and Completions Committee" and subsequently endorsed by the EUB. This letter supersedes Informational Letter 96-12,[236] which restricted the use of flare tanks until a number of design concerns were resolved to the satisfaction of the EUB and industry. The revised minimum standards were to be applied commencing 1 June 1998, for all oil and gas well drilling and servicing operations in Alberta where flare tanks are to be utilized.

(iv) *General Bulletin 98-15, "Release of Non-Confidential Interpreted Geological Data; Integrated Geological Database System"*[237]

Effective 22 June 1998, the EUB announced that non-confidential interpretive geological data contained in its integrated geological data base system would be available through computer terminal facilities of information services at the EUB's head office in Calgary. The complete data file will be available on computer later in 1998. If a well is confidential below a certain formation, the entire well's data will continue to be kept confidential.

(v) *General Bulletin 98-16, "1998 Administration Fees and General Assessment and Funding of Broad Industry Initiatives"*[238]

Since the EUB eliminated payment of fees for all applications effective 1 April 1998, revenue previously collected therefrom was now to be collected through an increase in the annual administration fees primarily affecting the oil and gas sector. The 1998 administration fee for the oil and gas industry sector was set at 99.6 percent of the rates specified for wells in s. 16.070 of the *Oil and Gas Conservation Regulations.*[239]

234 (2 June 1998).
235 (11 June 1998).
236 A.E.U.B., Informational Letter 96-12, "Use of Flare Tanks as an Alternative to Flare Pits" (1996).
237 (18 June 1998).
238 (25 June 1998).
239 Alta. Reg. 143/98.

CAPP and SEPAC jointly requested that the EUB's administration fee process also be used to collect $1,566,000 to fund broad industry initiatives in 1998. This increase adjusted the factor from 99.6 percent to 104 percent. Programs to be funded included environmental research, industry communication, and sour gas mapping for release rate guidelines.

(vi) *General Bulletin 98-30, "New or Revised Alberta Environmental Protection Documents: Code of Practice for the Release of Hydrostatic Test Water from Hydrostatic Testing of Petroleum Liquid and Gas Pipelines and Code of Practice for the Temporary Diversion of Water for Hydrostatic Testing of Pipelines"*[240]

Effective 1 January 1998, the code of practice for the release of hydrostatic test water from hydrostatic testing of petroleum liquid and gas pipelines was required for all pipelines under the authorities of the *Pipeline Act* and the *Environmental Protection and Enhancement Act*. A new code of practice for the temporary diversion of water for hydrostatic testing of pipelines also became effective 1 January 1999, and allows the diversion and use of water without obtaining an approval provided that the code of practice is followed.

(vii) *General Bulletin 99-4: Land Development Information Package*[241]

A new land use package service containing specific information extracted from the EUB records in the vicinity of a land parcel identified by a customer was unveiled. This package is intended for use by anyone planning land subdivision or development (or considering a land purchase for these purposes). Each package provides basic details on nearby oil and gas related facilities, wells, and coal mines. In addition to "vicinities specific data," a discussion of the EUB minium setback recommendations and guides to understanding well and pipeline data is included. The package contents include an overview of minimum setback recommendations, unique well identifiers, a description of how to use the EUB pipeline license register for determining basic pipeline details, and the EUB Guide 30,[242] which discusses ground disturbance near pipelines.

Provided that the EUB records show the described activity is present within the vicinity, the following items may also be included: the EUB licensed well information (including a separate listing of sour wells), pipeline plats showing the approximate location of the EUB licensed pipelines, battery information, and coal mine information.

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240 (17 December 1998).

241 General Bulletin 99-4, "'Land Development Information Package'; Introducing a New Service" (12 March 1999).

242 *Guide 30: Guidelines for safe construction near pipelines*, 2d ed. (A.E.U.B., 1998).

f. Interim Directives

(i) *Interim Directive ID98-3, "Well Records — Data Summary Forms"*[243]

This interim directive introduced requirements for submitting summary data for operations completed at a well after drilling, completion, reconditioning, or abandonment. The new process was implemented 1 January 1999, and any drilling or completions data submitted after that date must be filed in accordance with the requirements of Guide 59, "Well Drilling and Completion Data Filing Requirements."[244] This guide was designed to assist industry in the use and completion of five new data summary forms.

(ii) *Interim Directive ID98-4, "Electronic Capture of Well Test Data"*[245]

This Interim Directive outlined revisions to Guide 40 entitled "Pressure and Deliverability Testing Oil and Gas Wells; Minimum Requirements and Recommended Practices,"[246] which defined the new requirements for electronic submission of well test data. Effective 1 March 1999, a number of well tests must be submitted via signed and encrypted e-mail to the EUB in the appropriate format.

(iii) *Interim Directive ID98-5, "Electronic Capture of Gas Removal Permit Data"*[247]

This directive outlined revisions to the method of reporting monthly gas removal permit data to the EUB, which defined the new requirements for electronic submission of gas removal permit data. Effective 1 March 1999, all permitees are required to submit the gas removal permit data by using the gas removal data system located under digital/electronic submission facilities at the EUB's website. The electronic capture of gas removal permit data allows the EUB to carry out its mandate to provide for the recording and timely and useful dissemination of information regarding the energy resources of Alberta.

243 (20 October 1998).
244 (October 1998).
245 (2 December 1998).
246 (May 1999).
247 (21 December 1998).

(iv) *Interim Directive ID99-1, "Gas/Bitumen Production in Oilsands Areas Application, Notification and Drilling Requirements"*[248]

The EUB detailed new requirements for gas and bitumen production in oilsands areas in the Athabasca, Cold Lake, and Peace River areas. For wells drilled or completed after 1 July 1998, an operator must submit an application and obtain approval from the EUB before any gas, other than solution gas, can be produced. In addition, all such wells must be drilled deep enough to be able to log over the base of the oilsands deposit zone from which gas or bitumen is to be produced. These requirements do not apply to wells drilled for mining projects or for those that are otherwise exempt. The application must show that the gas is not associated with bitumen within the region of influence, or if associated, why gas production should be allowed considering the potential effect on future bitumen recovery. Applications to produce gas are not required to conduct short tests (*e.g.* three days) to obtain information on new wells. Since the EUB believes its decision on an application should be based on publicly available information, it is not prepared to treat any information submitted in support of an application as confidential. Where information is considered too sensitive to be included, an applicant takes the risk that other submitted information will be sufficient to support the application. If the EUB finds such information is inadequate, its decision may be delayed until substantive information is available. An application must include:

(1) a description of the scope of the gas project, including the number and location of new wells to be produced, the location, current status, and production plots for existing wells in the region of influence, and the interval to be produced;

(2) a discussion of the presence, size, and lateral extent of the gas zone to be produced and any associated bitumen and top water zones, including all relevant data used to support the geological interpretation, net gas and bitumen pay maps, and instructor maps; estimates of initial volumes in place; and cross-sections of the zones showing porosity tops and bases, fluid interfaces, test intervals and perforated intervals, pressure information, hydrogeological data, and any other relevant information;

(3) a discussion of whether the gas zone is associated with a bitumen zone and if so associated: (a) a discussion of whether the bitumen within the region of influence is exploitable with a reasonably foreseeable technology and economic conditions; (b) a discussion of the state of depletion of the gas zone, including a comparison of current pressure with initial pressure and cumulative gas production as a fraction of the initial volume in place; (c) an evaluation of the potential effect of gas production on bitumen recovery; (d) details of the applied-for wells and the reasonably foreseeable field development; (e) projected gas production profile for individual wells or expected aggregate

[248] (3 February 1999), ID99-1 (E.U.B.). It is noteworthy that in the reply argument of the SPG in connection with the Gulf application to shut in associated gas production in the Surmont area, see *supra* note 226, it is argued that this interim directive has no legal force or effect as it is "predicated on the existence of a regulation which does not exist (and which it is submitted the [EUB] is not authorized to create)." See also the amendments to the *Oil and Gas Conservation Act* and the *Oil Sands Conservation Act*.

production profiles within common regions of influence; and (f) proposed reservoir abandonment pressure;

(4) maps showing petroleum and natural gas and oilsands lessors and lessees; and

(5) confirmation that the notification requirements have been satisfied and that there has been adequate exchange of information with potentially affected parties and an attempt to resolve differences of opinion.[249]

Notification requirements were established to expedite the application process. In addition, the EUB required all wells to be drilled deep enough to be able to log over the base of the oilsands deposit containing the zone from which gas or bitumen is to be produced unless this would result in trespass. In the event of trespass, wells must be drilled deep enough to be able to log over the base of the oilsands zone from which production is to be obtained.

(v) *Interim Directive ID99-2, "Revised Policy on Administration of Oil MRL's and Overproduction"*[250]

Effective 1 March 1999, the administration of overproduction has been amended as follows:

(1) To relieve some of the onerous consequences of overproduction, the 20 percent cumulative penalty will be eliminated. The 50 percent monthly penalty will be retained as a deterrent against overproduction.

(2) To clarify expectations and promote more timely retirement of overproduction, any overproduction status exceeding 10 percent of a well's adjusted maximum rate limitation ("MRL") must be retired (*i.e.* reduced to a zero status) within three months.

(3) Successful application for an increase in MRL, good production practice status, or relief from gross overriding royalty penalties will normally be approved for a pool effective on the first day of the month following the decision, rather than being delayed until all overproduction is retired.[251]

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249 Interim Directive ID99-1, *ibid.* at 3-5.
250 (12 February 1999).
251 *Ibid.* at 3-4.

(vi) *Interim Directive ID99-3, "Surface Casing Vent Flow/Gas Migration (SCVF/GM) Testing and Repair Requirements"*[252]

This directive rescinded Interim Directive ID95-01,[253] and its requirements were to take effect immediately. Industry was required to address the surface casing vent flow and gas migration issue at the initial planning of a well drilling program. The key changes included the following: wells with no in-vent flow problems will not be required to conduct further testing if five years of non-serious annual test results are on file; pre-approval will only be required for non-routine repair programs, as opposed to all repair programs; a repair notification form for all repairs was now to be submitted within thirty days of the repair; and post repair and testing audits were introduced based on random selection, public, or government concerns or the compliance history of the licensee. An enforcement letter was introduced establishing consequences for failing to test or report a surface casing vent flow. The time for checking a new well for a surface casing vent flow was extended to within ninety days of rig release, as opposed to thirty days. In addition, licensees had to submit an application to produce any serious surface casing vent flow although no application was required to tie in a non-serious surface casing vent flow.

C. BRITISH COLUMBIA

1. BRITISH COLUMBIA UTILITIES COMMISSION

a. Decisions

(i) *1998 Application by B.C. Gas Utility Ltd. for a Certificate of Public Convenience and Necessity regarding its Southern Crossing Pipeline Project*[254]

By way of follow up to the BCUC's decision dated 3 April 1998,[255] BC Gas applied for a certificate of public convenience and necessity ("CPCN") for the Southern Crossing Pipeline ("SCP") project on 11 December 1998. BC Gas added a compressor station located at Hedley, British Columbia, on its existing Kingsvale to Oliver pipeline and proposed that the review of the application be conducted in the context of the decision dated 3 April 1998, that only new issues be addressed. BCUC Order G-121-98, dated 21 December 1998,[256] established a timetable for a workshop, information requests, and written submissions on the completeness of the application and related peaking supply agreements and transportation service agreements, along with participant views on any further proceedings which may be necessary to consider their filings in the context of either the decision or as new initiatives. The BCUC determined that a limited oral public hearing was needed to evaluate changes to the net benefits of the pipeline and alternative proposals, and ordered that such hearing be held, commencing

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252 (16 February 1999).

253 "Surface Casing Vent Flow/Gas Migration Requirements" (1995).

254 (22 February 1999), G-21-99 (B.C.U.C.).

255 *Re: An application by BC Gas Utility Ltd. for a Certificate of Public Convenience and Necessity regarding its Southern Crossing Pipeline Project* (3 April 1998), G-31-98 (B.C.U.C.).

256 *Re: An application by BC Gas Utility Ltd. for a Certificate of Public Convenience and Necessity regarding its Southern Crossing Pipeline Project* (21 December 1998), G-121-98 (B.C.U.C.).

29 March 1999. The British Columbia Hydro and Power Authority ("BC Hydro") was directed to file a detailed submission quantifying all benefits and costs to its rate payers of the peaking gas purchase agreement and the firm tendered transportation service agreement that it entered into with BC Gas. BC Gas was also directed to file a written submission providing reasons in support of its request for confidentiality of the undisclosed premiums in the peaking gas purchase agreements.

(ii) *Request by Westcoast Energy Inc. for Disclosure of the Undisclosed Premiums in the Peaking Gas Purchase Agreements*[257]

In this decision, the BCUC approved the request by Westcoast that it direct BC Gas to fully disclose the undisclosed premiums in the peaking gas purchase agreements only with respect to previously undisclosed information in ss. 5.1 and 5.3 of the BC Hydro peaking gas purchase agreement. Westcoast's request was otherwise denied. The BCUC evaluated the undisclosed contents of the BC Hydro, and PG&E Energy Trading, Canada Corporation ("PG&E") peaking agreements against two criteria: (1) the importance of the undisclosed information to the SCP proceeding; and (2) the requirement for confidentiality of that information on the basis of commercial sensitivity. In reviewing the undisclosed content of the two agreements, the BCUC determined that the only undisclosed information that was relevant to the SCP proceeding was information related to BC Gas' assertions of a net present value of the peaking agreements in support of the project. In evaluating each of these sections to decide if the value of the undisclosed information to such proceeding outweighed the potential for commercial harm to BC Gas, BC Hydro, and PG&E, the BCUC considered that the potential commercial harm to BC Hydro and BC Gas was less severe than in the case of PG&E. As the primary purpose of BC Hydro's natural gas contracting was to provide natural gas supply to thermal generating units supplying power to BC Hydro, it was likely to have more non-gas alternatives that it could use when BC Gas calls on peaking gas and hence would have less exposure to a gas supplier or purchaser who was attempting to use disclosed information to gain commercial advantage than did PG&E. The BCUC found, that although the undisclosed information in the peaking agreement with BC Hydro was commercially sensitive, on balance, disclosure for the purpose of the SCP proceeding outweighed the potential commercial harm to BC Hydro. The public interest was therefore deemed to be best served by directing BC Gas to disclose the relevant provisions of the BC Hydro peaking gas purchase agreement in its entirety while keeping the same information in the PG&E agreement confidential.

(iii) *Request by Westcoast Energy Inc. for Disclosure of the Specified Maximum in CTS Support Agreement*[258]

Further to matters concerning the SCP application in which BC Gas had agreed with BC Hydro on a by-pass rate for transportation service on BC Gas' coastal transmission system ("CST"), BC Hydro apparently filed a CST support agreement and a put option agreement that deleted the "Specified Maximum" as defined in the CST support

[257] (25 March 1999), G-34-99 (B.C.U.C.).

[258] (25 March 1999), G-35-99 (B.C.U.C.).

agreement, requesting that it be kept confidential. BC Hydro argued that it filed this support agreement in connection with the SCP application and not in connection with the by-pass transportation agreement application and that disclosure of it was not relevant to review the by-pass rate. It further argued that, if in proceeding to build a by-pass pipeline, the Specified Maximum could be used by others in negotiations to set a minimum price for what they would charge for construction of a by-pass pipeline, disclosure would be adverse to the commercial interests of BC Hydro and its customers. BC Hydro also argued that such disclosure would reveal commercially sensitive information of a non-utility corporation (BC Gas Inc.) and that the parties to the SCP application were not prejudiced by not knowing the actual amounts of the Specified Maximum. BC Gas Inc. supported the request for confidentiality.

In Westcoast's interpretation, if BC Gas Inc. was required to make any payment to BC Hydro, then BC Gas Inc. could, in lieu of making the payment, elect to require BC Hydro to assign to it the SCP transportation capacity held by BC Hydro and the BC Hydro peaking gas purchase agreement, for up to two years from the in-service date of the pipeline. The closer the Specified Maximum was to the by-pass rate provided for in the by-pass transportation agreement, argued Westcoast, the greater the likelihood that the approved by-pass rate would exceed the Specified Maximum and therefore the greater the likelihood that BC Gas Inc. would acquire the pipeline capacity. Westcoast further argued that the extent of BC Hydro's commitment to the SCP was central to BC Gas' new CPCN application and that the level of the Specified Maximum was directly related to this issue.

The BCUC accepted Westcoast's position that the support agreement could result in BC Hydro assigning its peaking agreement and transportation agreement to BC Gas Inc. for the first two years that the pipeline was in service. Recognizing that the put option agreement and support agreement were public information, the BCUC did not consider that knowledge of the Specified Maximum would add materially to Westcoast's ability to make such arguments. Since BC Gas Inc., one of the primary signatories to the support agreement, was a non-regulated corporation, the BCUC expressed concern that disclosure of the Specified Maximum could be harmful to its commercial interests. It therefore found that disclosure would not be in the public interest and denied Westcoast's request.

(iv) *Generic Hearing into the Rate of Return on Common Equity*[259]

The BCUC rescinded its earlier Order No. G-26-99,[260] which set down an oral public hearing into the appropriate rate of return on common equity and capital structures for various utilities to commence 31 May 1999. Instead, the BCUC ordered an oral public hearing to be held into the appropriate return on common equity for a low-risk benchmark utility and into future processes or mechanisms that could be employed to improve the determination of a return on common equity for such utilities in future years, commencing 21 June 1999.

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[259] (7 April 1999), G-38-99 (B.C.U.C.).

[260] *A Generic Public Hearing into the Rates of Return on Common Equity* (15 March 1999), G-26-99 (B.C.U.C.).

b. Guidelines

(i) *Participant Assistance/Cost Award Guidelines*[261]

In 1998, the BCUC requested utilities and interested parties to provide comment on all issues pertaining to participant assistance and cost awards. Guidelines respecting participant eligibility, application for a cost award, interim awards, participant assistance, and eligible costs and rates were then established.

When making participant assistance and cost awards, the BCUC will consider its approved budget for participant funding as well as: whether the participant represents a substantial interest in the proceeding and will be affected by the outcome; whether the participant has contributed to a better understanding of the issues; whether the costs incurred for the purpose of participating in the proceeding are fair and reasonable; whether, without the award, the participant would be able to participate effectively; whether the participant has joined with other groups with similar interests to reduce costs; and any other matter appropriate in the circumstances.

Participants who intend to apply for a cost award must submit a budget by the date set out in the order established in the proceeding. The budget estimate should address a participant's eligibility, identify key issues that it will examine, indicate whether the participant expects to lead evidence, and include an estimate of the number of proceeding and preparation days. Final applications for a cost award must be made within thirty days following the last day of a proceeding, setting out the reasons for such an award. The application should be supported by a statement of costs with the appropriate receipts and invoices, together with a sworn affidavit and address any reasons why the actual application differs from its budget estimate. Costs are to be awarded by order no later than two months after the hearing decision has been issued. Once in receipt of the BCUC's decision, an affected participant may seek a reconsideration of its award, provided an application to do so is filed within ten working days. Schedules to these guidelines set out the maximum amount of certain costs that will be funded.

c. British Columbia Oil and Gas Commission Information Letters

(i) *Background*

Numerous employees of the Ministries of Energy and Mines, Forests and Environment, and Lands and Parks were consolidated into a new British Columbia Oil and Gas Commission (the "Commission") on 5 October 1998. The Commission provides a new streamlined service for the oil and gas and pipeline industry.

The *Petroleum and Natural Gas Act*, the *Utilities Commission Act* and the *Pipeline Act* (see sections II.B.3.b. to II.B.3.d., above) were all subsequently amended by the *Oil and Gas Commission Act*. These amendments transferred oil and gas and pipeline regulatory authority to the Commission. Further, all regulations relating to oil, gas, and

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261 (30 November 1998), G-97-98 (B.C.U.C.).

pipelines under the *Forest Act*, *Forest Practices Code of British Columbia Act*,[262] *Heritage Conservation Act*,[263] *Land Act*, *Waste Management Act*,[264] and *Water Act*[265] have been transferred to the jurisdiction of the Commission. The Commission now has statutory authority to issue permits, licenses, and approvals in relation to oil, gas, and pipelines under all of the statutes. However, the procedures for the various applications remain in place and are still governed by their original legislation and regulations.

The Lieutenant-Governor-in-Council may make regulations respecting policies and procedures to be followed by the Commission in exercising its duties and responsibilities, but the regulations will still be subject to the *Petroleum and Natural Gas Act* and the *Pipeline Act* and their corresponding regulations. The Commission has indicated that it is planning to introduce some procedural changes over the next year to further streamline the procedures. However, to date, the Commission has generally followed those procedures of the predecessor ministries.

The ministries will continue to be involved in land-use planning in the northeast and will be available to advise the Commission on complex regulatory issues. The Ministry of Energy and Mines will still administer oil and gas tenures and collect royalties on the production of oil and gas. The environmental assessment process will still apply to oil and gas and pipeline projects that meet the criteria of the *Environmental Assessment Act*.

(ii) *Information Letters*

(1) *New Fees for Oil and Gas Activities and New Production Levy*[266]

On 19 May 1998, Premier Glen Clark and Norm McIntyre, Chair of CAPP, announced an agreement to stimulate oil and gas exploration and development in British Columbia. This agreement included a reduction in oil and natural gas royalties, a memorandum of understanding with First Nations regarding oil and gas developments, and the creation of the Gas Commission, a self-described single-window regulatory and permitting agency for the upstream oil and gas industry and pipelines. The Commission is to be funded by the industry through a range of fees and a levy on production. The new fees and levy came into effect on 23 October 1998, in conjunction with the *Oil and Gas Commission Act*.

Part of the Commission's costs will be funded through a levy on oil and gas production. The levy previously collected under the *Natural Gas Price Act*[267] has been eliminated and replaced with a levy under the *Oil and Gas Commission Act*. The established rates are $0.21 per thousand cubic metres for natural gas and $0.42 per thousand cubic metres for oil. Producers will be invoiced for the levy on a monthly

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262 R.S.B.C. 1996, c. 159.
263 R.S.B.C. 1996, c. 187.
264 R.S.B.C. 1996, c. 482.
265 R.S.B.C. 1996, c. 483.
266 (23 October 1998).
267 R.S.B.C. 1996, c. 329.

basis in the same way they were invoiced for the *Natural Gas Price Act* levy. The letter specifies the applicable fees according to activity.

(2) *1999 Well Testing*[268]

Reservoir pressure measurements are required on each producing oil or gas pool in British Columbia in accordance with s. 95 of the *Drilling and Production Regulation*. The Commission requires adequate areal pressure surveys coverage annually, although in some instances less frequent surveys have been approved. The information letter sets out the minimum reservoir pressure test requirements for each producing pool. A coordinating operator's responsibilities regarding surveys and testing are also set out. Finally, the test methods, including well deliverability tests, are designated.

(3) *Reporting Emissions from Glycol Dehydrators*[269]

The purpose of this information letter is to remind operators of the reporting requirements of the program as detailed in *Best Management Practices for the Control of Benzene Emission from Glycol Dehydrators (BMP)*.[270] Specifically, operators are to report by 1 March 1999, data demonstrating that all dehydrators emit not more than nine tonnes of benzene per year.

(4) *Ministry of Transportation and Highways Road Ban Information*[271]

The Ministry of Transportation and Highways has prepared an internet site[272] to provide current information regarding highway and road load restrictions. This information will be of interest to the petroleum and petroleum services industry and the pipelines industry when preparing operations for the annual spring road bans.

(5) *1999/2000 Oil and Gas Commission Levy Rate*[273]

In accordance with s. 3(4) of the *Oil and Gas Commission Levy Regulation*, thirty days' notice of the 1999/2000 fiscal year levy rates was given. The rates will be $0.21 per thousand cubic metres for natural gas and $0.42 per thousand cubic metres for petroleum.

(6) *Access Roads / Petroleum Development Roads*[274]

In response to reports of gates being constructed without the required permission on access roads servicing oil and gas industry operations in northeastern British Columbia,

268 (25 January 1999).

269 (25 January 1999).

270 Published by and available on Canadian Association of Petroleum Producers website at <www.capp.ca>.

271 (2 February 1999).

272 *Load Restrictions*, online: British Columbia Ministry of Transport and Highways <http://www.th.gov.bc.ca /bchighways /camroad /loadrestrictions.htm> (last modified: 3 March 1999).

273 (1 March 1999).

274 (1 April 1999).

the Commission issued this information letter. It is to serve as a reminder that construction of gates on oil and gas industry access roads and the petroleum development roads must be pre-approved by the Commission. Generally, short-term approvals for gates may be granted during the drilling of a well, where there are safety concerns, or the drilling is in an environmentally sensitive area. Maintenance of longer term gates require review by a public process as well as by other agencies.[275] Gates are not authorized where road operators are attempting to resolve road use agreements with other industrial users.[276] Where an unauthorized gate is identified, the operator will have to demonstrate the necessity for the gate or remove it immediately.

D. NOVA SCOTIA

1. DECISIONS

a. Canada-Nova Scotia Offshore Petroleum Board[277]

(i) *1999 Sable Gully Policy*

On 5 May 1998, the Canada-Nova Scotia Offshore Petroleum Board ("CNSOPB") announced its decision to not accept any bids submitted on land that was adjacent to the "Sable Gully."[278] Further, no additional call for bids would be issued, nor would any authorization for exploration be forthcoming for activities near Sable Gully before 1 November 1998. This provides the Department of Fisheries and Oceans ("DFO") with its requested six month period to complete a "Gully Conservation Strategy."[279]

On 9 December 1998, the DFO released "The Sable Gully Conservation Strategy." The policy includes a map of the region that sets out an area of interest ("AOI") that will be subject to a restriction on new activities, including exploration and production. The CNSOPB has since extended the 5 May 1998, decision to remain in force until the end of 1999.[280]

(ii) *1999 Policy on Seismic Fisheries Liaison Observers*

The CNSOPB has released its policy respecting "Class Environmental Screening for Seismic Exploration on the Scotian Shelf" to mitigate measures and operating conditions for the conduct of seismic operations using airguns or airgun arrays. The program provides for a liaison with fishermen in the vicinity of seismic programs. The

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275 Ministries of Environment, Lands and Parks, and Forests.

276 The *Petroleum Development Road Regulation* provides mechanisms to address road use issues with other industrial users.

277 The Canada-Nova Scotia Offshore Petroleum Board is an independent, joint agency of the Governments of Canada and Nova Scotia, which is responsible for the regulation of petroleum activities and resources offshore Nova Scotia.

278 CNSOPB News Release, "Results of Calls for Bids for Exploration Licenses Offshore Nova Scotia" (5 May 1998).

279 The CNSOPB believed that the Gully Conservation Strategy was necessary to evaluate the potential environmental effect of petroleum activities on the Sable Gully ecosystem.

280 Sable Offshore Energy Inc. has also been requested to amend its "Code of Practice" to reflect the AOI.

observer would meet with the fisheries groups prior to commencing a seismic program to help reduce any potential conflict at sea. The CNSOPB states that the program worked well in 1998, and as a result, the CNSOPB has decided to continue the requirement for a fisheries liaison observer to be onboard all seismic vessels using airguns or airgun arrays in the CNSOPB's jurisdiction.

(iii) *Policy on Discharge of Oil-based Muds*

In December 1997, the CNSOPB produced its decision report for the benefits plan and development plan for the Sable Offshore Energy Project.[281] Condition 21 of the development plan decision report outlined a discharge limit of 1 percent low toxicity mineral oils ("LTMO") by weight on cuttings which would be imposed on the Sable project after 31 December 1999. The CNSOPB, in consultation with Sable Offshore Energy Inc., has determined that present technology cannot achieve this limit.

The discharge limit has been extended to cover all drilling operations under the CNSOPB. The following will therefore apply:

- prior to 31 December 1999, discharges of hydrocarbon-based drilling fluids (including LTMO) on cuttings shall be in compliance with the CNSOBP's *Offshore Waste Treatment Guidelines*[282] (15 percent by weight on cuttings), and hydrocarbon based drilling fluids will only be used in well sections where it is a technical requirement;

- after 31 December 1999, discharges of hydrocarbon-based drilling fluids on cuttings shall not exceed 1 percent by weight on cuttings, unless specifically authorized by the CNSOPB in exceptional circumstances; and

- the present policy is that all exploration wells shall use water based muds.

2. GUIDELINES

a. Guidelines Respecting the Selection of Chemicals Intended to be Used in Conjunction with Offshore Drilling & Production Activities on Frontier Lands[283]

The *Offshore Chemical Selection Guidelines* apply to the selection and use of all offshore drilling and production chemicals which may be discharged into the marine environment. These discharge streams (*i.e.* cuttings, cooling water, and produced water) would normally be authorized or regulated by one of the Canada-Newfoundland

281 *Sable Offshore Energy Project Benefits Plan Decision Report; Development Plan Decision Report* (December 1997) (C.N.S.O.P.B.).

282 (September 1996).

283 (January 1999) [hereinafter *Offshore Chemical Selection Guidelines*]. These guidelines were prepared jointly by the Canada-Newfoundland Offshore Petroleum Board, the Canada-Nova Scotia Offshore Petroleum Board, and the National Energy Board with the assistance of a government and industry working group that was established for this purpose.

Offshore Petroleum Board, the CNSOPB, or the NEB.[284] The guidelines set out the thirteen-step selection flowchart to allow operators to make an informed decision on the environmental acceptability of the proposed chemicals for offshore use. This process should be documented and conducted according to hazard assessment techniques. The process documented should be submitted to the appropriate regulatory body to facilitate audits. Audits will be conducted to ensure compliance with the guidelines. If a chemical passes the hazard analysis, then it will be acceptable for use; if it does not, a substitute must be found.

284 These guidelines are not applicable for the selection and use of domestic chemicals or chemicals that are used on-board offshore drilling or production facilities that are not associated with production or drilling (*e.g.* cleaning products, paints, *etc.*). Further, these guidelines do not apply to the selection of chemicals which may be discharged from vessels under contract to perform specific tasks. In these cases, international requirements for the safe use of chemicals will be applied.