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

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In the following discussion the authors summarize recent developments in statutes, regulations and regulatory decisions which may be of particular interest to oil and gas lawyers in Canada. The scope of the summary is limited to federal law and the laws of Alberta, British Columbia and Saskatchewan. Notwithstanding this limitation, the developments in this area of law are numerous and this paper seeks only to draw attention to them without attempting to provide detailed descriptions or analysis.

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I. LEGISLATIVE CHANGES

A. FEDERAL LEGISLATION

1. Regulations

a. *Frontier Lands Petroleum Royalty Regulations*, SOR/92-26. (Registered December 12, 1991)

These regulations made pursuant to the *Canada Petroleum Resources Act*[1] revoked the *Frontier Lands Petroleum Royalty Regulations, 1987*[2] and revised the royalty rate payable with respect to Frontier Lands. Subject to the adjusted cumulative cost base and return allowances, the described royalty is as follows:

1. 1st production month to 18th production month — 1% of gross revenues;
2. 19th production month to 36th production month — 2% of gross revenues;
3. 37th production month to 54th production month — 3% of gross revenues;

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1. R.S.C. 1985, c. 36.
2. SOR/88-348.

4. 55th production month to 72nd production month — 4% of gross revenues;
5. 73rd production month to last production month preceding payout — 5% of gross revenues; and
6. upon payout, the greater of 30% of net revenues and 5% of gross revenues.

b. *Federal Real Property Regulations*,
SOR/92-502. (Registered August 27, 1992)

The *Federal Real Property Act*[3] serves as the regulatory base for the acquisition and disposition of federal oil and gas rights. These regulations do not directly affect how federal oil and gas rights may be acquired from the federal Crown but are meant to ensure that existing internal government operating procedures are streamlined so that fair and equitable access to disposition of federal oil and gas rights can be assured.

c. *Newfoundland Off-Shore Petroleum Drilling Regulations*,
SOR/93-23. (Registered January 28, 1993)

These regulations, made pursuant to the *Canada-Newfoundland Atlantic Accord Implementation Act*,[4] are based upon federal regulations contained in the *Canada Oil and Gas Drilling Regulations*[5] which were promulgated in 1979 under the *Oil and Gas Operations, Canada Act*.[6] However, when the *Canada-Newfoundland Atlantic Accord Implementation Act*[7] came into force in 1987, all regulations promulgated under the *Oil and Gas Operations, Canada Act*[8] were no longer valid in Newfoundland. Accordingly, these regulations were passed to provide for the exploration and drilling for, and the production and conservation, processing and transportation of petroleum in the Newfoundland off-shore area. These regulations do not differ substantially from those contained in the *Canada Oil and Gas Drilling Regulations*.[9]

2. Evolving Matters

a. Bill C-92, *An Act to Amend the Income Tax Act*,
3d Sess., 34th Parl., 1993. (Second Reading, May 6, 1993)

(i) *Removal of Mandatory CCEE Deduction for Principal Business Corporations*

While taxpayers are generally able to make an optional write-off of up to 100% of their cumulative Canadian exploration expenses ("CCEE") balance, principal-business corporations are required to deduct a portion of their CCEE balances. A recently proposed

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3 S.C. 1991, c. 50.
4 S.C. 1987, c. 3.
5 SOR/79-82.
6 R.S.C. 1985, c. O-7, formerly titled the *Oil and Gas Production and Conservation Act*.
7 *Supra* note 4.
8 *Supra* note 6.
9 *Supra* note 5.

amendment to the *Income Tax Act*[10] will remove this mandatory CCEE deduction for such corporations. The amendment applies to taxation years after December 2, 1992.

(ii) *Resource Allowance at Partnership Level*

The resource allowance is designed to compensate for the non-deductibility of Crown royalties and similar Crown payments. The resource allowance is a deduction of 25% of certain resource profits, such that only 75% of such profits are subject to tax. Under the present structure of the Act, a partnership earning resource profits would calculate the resource allowance at the partnership level. In contrast, claims for Canadian Exploration Expense ("CEE"), Canadian Development Expense ("CDE") and Canadian Oil and Gas Property Expense ("COGPE") are made by partners. A recently proposed amendment to the Income Tax Regulations will result in the resource allowance being claimed by partners, rather than by a partnership.

(iii) *Time Extended for Renunciating CDE Under the Flow-Through Share Rules*

The flow-through share rules permit a principal-business corporation to renounce CEE, CDE and COGPE to a person who acquires flow-through shares. Pursuant to the rules, the expenses must be incurred on or after the date the agreement to subscribe for shares is entered into, and before 24 months from the end of the month in which such an agreement is entered into. The actual renunciation must occur within 30 days after the end of the 24 month period. The amendments allow a renouncing corporation to renounce such expenses before March of the first calendar year commencing after the 24 month period. The draft provision relates to expenses incurred after February 1986.

(iv) *Deemed Recharacterization of CDE*

Draft amendments will allow a principal-business corporation to renounce specified CDE to a flow-through shareholder while that shareholder will be deemed to have received CEE rather than CDE. The recharacterization provision relates to CDE incurred after December 2, 1992. The renouncing corporation and corporations associated with it may not renounce and have recharacterized more than a total of $2 million CDE in a calendar year.

(v) *CDE in First 60 Days of Calendar Year*

The Act deems the renunciation of CEE by a corporation in the first 60 days of the calendar year to have been incurred by the corporation at the end of the preceding calendar year. The rules are to be amended to allow specified CDE to benefit from the same rule for expenses incurred after 1992.

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10 R.S.C. 1985, c. I-3.

b. Bill C-103, *An Act to provide for the repeal of the Land Titles Act and to amend other Acts in relation thereto*, 3d Sess., 34th Parl., 1993. (Second Reading, March 11, 1993)

This legislation provides that upon enactment of a land titles ordinance to replace the *Land Titles Act*[11] in the Yukon Territory and the Northwest Territories, the Governor-in-Council may repeal the *Land Titles Act*[12] in respect of such territory if such ordinance is established upon the principles of the Torrens system for land registration.

c. Bill C-106, *An Act to Amend certain petroleum related acts in respect of Canadian Ownership Requirements and to confirm the Validity of a certain Regulation*, 3d Sess., 34th Parl., 1993. (First Reading, December 10, 1992)

This Bill will amend the *Canada Petroleum Resources Act*[13] by eliminating the prohibition contained in s. 46 of such Act that no production license shall be issued to an interest owner who has less than a 50% Canadian ownership rate. In this Bill the only qualification for a production license will be contained in the new s. 44 which states that no corporation incorporated outside of Canada shall hold a production license. In addition, all of Part 5 of the *Canada Petroleum Resources Act*[14] which deals with the determination of the Canadian ownership rate will be repealed. Similar changes were also made such that the Canadian ownership requirements under the *Canada-Newfoundland Atlantic Accord Implementation Act*[15] and the *Canada-Nova Scotia Off-Shore Petroleum Resources Accord Implementation Act*[16] are consistent with that proposed for the *Canada Petroleum Resources Act.*[17]

d. *Canadian Environmental Assessment Act*, S.C. 1992, c. 37. (Assented to June 23, 1992)

Proclamation of the *Canadian Environmental Assessment Act* (Bill C-13) is awaiting finalization of the regulations. There continues to be ongoing discussions and criticism of the regulations. One of the main criticisms is that the regulatory impact assessment failed to look at the administrative costs to governments of implementing the federal assessment process. The cost of implementing the process will bear directly on the effectiveness of the process. Also, "harmonization agreements" or memorandums of understanding between the federal government and the various provinces have not been concluded. Those agreements will provide for a harmonization between the federal and provincial assessment processes in order to avoid a duplication of processes. Not all provinces have entered into such agreements at this time. Alberta is one of the few provinces which has entered into a harmonization agreement with the federal government.

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11 R.S.C. 1985, c. L-6.
12 *Ibid.*
13 *Supra* note 1.
14 *Ibid.*
15 *Supra* note 4.
16 S.C. 1988, c. 28.
17 *Supra* note 1.

There has also been considerable discussion over the "laws list" which will identify the provisions of a myriad of Acts and regulations which will trigger the federal environmental assessment process. (Discussions indicate the laws list may include anywhere from 150 to over 900 statutory provisions.) The laws list is currently in the process of being finalized.

e. *Comprehensive Air Quality Agreement for Canada*

An agreement has been entered into between the federal government and the various provinces regarding air quality in Canada. An advisory committee has been established which will look at all air issues in Canada on a regional and national basis. The oil and gas industry is represented on the advisory committee by the Canadian Association of Petroleum Producers. Of concern to the industry will be how emissions of volatile organic compounds and oxides of each of sulphur and nitrogen will be dealt with by the advisory committee.

f. *National Pollutant Release Inventory*

Pursuant to s. 16(1) of the *Canadian Environmental Protection Act*,[18] the *National Pollutant Release Inventory* ("NPRI") was promulgated in the March 27, 1993 issue of the Canada Gazette Part 1. The purpose of the NPRI program is to track toxic substances and to ensure "cradle to grave" treatment of those substances. It is also to provide an opportunity for the public to obtain information on toxic substances. The notice published in the Gazette contains four schedules which provide for the 178 substances to be covered by the inventory, facilities which are subject to NPRI reporting requirements, the types of activities covered by NPRI and the types of information that must be reported to the Ministry by the deadline of June 1, 1994.

According to the notice, facilities that come within the following criteria must submit a report to the Minister (with certain exceptions):

1. if the facility manufactures, processes or otherwise uses at least ten tons per year of any of the 178 substances listed in the inventory, at a concentration of 1% by weight or greater; or

2. if the facility has employees which work a total of not less than 20,000 man hours during 1993.

The report will require facilities to break down raw material and waste streams into constituent components and to provide what may be complex calculations to determine estimates of the amount of each chemical substance that is released into the environment or shipped as waste. Some facilities which are exempt from the reporting requirements (and which may be of interest to the oil and gas industry) are research testing facilities; maintenance and repair facilities for transportation vehicles; facilities for the distribution,

[18] R.S.C. 1985, c. 16.

storage or retail sale of fuel; wholesale or retail of items which contain listed substances (provided the substance is not released into the environment in the normal use of the facility); retail sale of substances listed in the inventory; and drilling or operating wells to obtain oil and gas products which contain substances in the inventory, but not those facilities engaged in further processing of these oil and gas products.

The information required under NPRI for the year 1993 must be reported to the federal Minister of the Environment by June 1, 1994. Implementation of the program is likely to increase general and administrative costs incrementally at those facilities which are required to report.

B. ALBERTA LEGISLATION

1. Statutes

a. *Energy Resources Conservation Amendment Act, 1992*, S.A. 1992, c. 14. (Effective June 26, 1992)

This legislation changes two sections of the *Energy Resources Conservation Act.*[19] Section 23 of the Act which deals with cooperation of the ERCB with governmental or other agencies inside or outside of Alberta has been repealed and replaced with a more comprehensive provision.[20] The Board now has authority to "conduct a hearing, inquiry or investigation ... jointly or in conjunction with another board or commission or other body constituted in Alberta,"[21] without obtaining any further approval from the Lieutenant Governor-in-Council. Arrangements between the Board and either the Government of Canada or any government of a jurisdiction outside Alberta (or agencies of such governments) which relate to the purposes of the Act remain subject to the approval of the Lieutenant Governor-in-Council.[22]

The second amendment[23] to the Act gives the Board greater flexibility in the orders it may seek from the Court of Queen's Bench against a person who fails to comply with an ERCB order. Prior to this amendment, s. 34 of the Act gave the Board the right to seek restraining orders from the Court for the prohibition of conduct which did not comply with the requirements of an ERCB order or direction. The new provision of the Act complements this existing right with the right to apply to the Court of Queen's Bench for an order requiring a "person or his employees or agents" to comply with an ERCB order or direction in instances where such person has failed to comply with the ERCB order or direction alone.

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19 R.S.A. 1980, c. E-11.

20 *Energy Resources Conservation Amendment Act, 1992*, S.A. 1992, c. 14, s. 2.

21 *Supra* note 19, as amended, s. 12(1).

22 *Ibid.* s. 23(2).

23 *Supra* note 20, s. 3.

b. *Mines and Minerals Amendment Act, 1992,*
S.A. 1992, c. 20. (Effective June 26, 1992)

This amending statute varies a number of the provisions of the *Mines and Minerals Act*[24] which deal with the failure of any person to pay the Crown royalty on any mineral that is subject to the Act.

The failures to pay the Crown's royalty share of a mineral may be generally categorized as those involving late payment or improper delivery, those involving fraud or negligent misrepresentation, those involving arrangements, transactions, or agreements which have the effect of "artificially or unduly" reducing the Crown royalty, and those instances in which the person taking the Crown mineral lacks any agreement or other statutory authority which would allow him to do so.

Crown royalty on a mineral may be payable in kind, in the consideration received for the Crown's royalty share when the mineral is disposed of by an agent, or by means of a money royalty. Many of the amended provisions have been changed to include a reference to the payment of "an amount owing on account of a money royalty."

An objection to the Minister's calculation or recalculation of the royalty payable to the Crown may be filed pursuant to a new provision[25] to become s. 39.01 of the Act. As well, a new s. 53.1[26] has been added to the Act to provide for the calculation of compensation due to the Crown for the unauthorized winning, working or recovery of a mineral.

c. *Miscellaneous Statutes Amendment Act, 1992,*
S.A. 1992, c. 21. (Effective dates vary)

Among the legislation amended by this omnibus amending statute is the *Law of Property Act*[27] (effective on proclamation). The amendments to that Act by the addition thereto of s. 59.2 relate to the priority of charges on land that are created and registered in compliance with the *Personal Property Security Act.*[28] Note that agreements registered under either the *Business Corporations Act*[29] or the *Companies Act*[30] are deemed to be registered as of the date of their original registration under the *Law of Property Act*[31] only until September 30, 1993 unless a new financing statement has been filed under the *Personal Property Security Act*, pursuant to s. 59.2 (10) of the Act. (Filing a new financing statement prior to September 30, 1993 will preserve the original registration date).

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24 R.S.A. 1980, c. M-15.
25 *Mines and Minerals Amendment Act, 1992*, S.A. 1992, c. 20, s. 4.
26 *Ibid.* s. 8.
27 R.S.A. 1980, c. L-8.
28 S.A. 1988, c. P-4.05.
29 S.A. 1981, c. B-15.
30 R.S.A. 1980, c. C-20.
31 *Supra* note 27.

Section 59.2 (11) of the Act provides that where a charge on land which has been created by an agreement executed after September 30, 1990 but prior to the proclamation of s. 59.2 (which proclamation occurred November 1, 1992) is registered within 60 days of such proclamation, the charge on land shall be deemed to have been registered as at the date of proclamation. This 60 day period lapsed on December 30, 1992.

d. *Alberta Environmental Protection and Enhancement Act*, S.A. 1992, c. E-13.3. (Effective September 1, 1993)

The long awaited *Alberta Environmental Protection and Enhancement Act* ("*AEPEA*") was finally proclaimed, to be effective September 1, 1993. The regulations pursuant to that Act have also been finalized and filed. The *AEPEA* and the regulations do not lend themselves to a brief view and therefore are not within the scope of this paper. Suffice it to say that the major impacts on the oil and gas industry of the *AEPEA* and the regulations will be in the approvals process, the increasing importance of the Environmental Appeal Board in respect of the appeals of approvals and conditions of approvals (which has been the experience in Ontario), releases of substances, the duty to report those releases and to take remedial measures and the Minister's authority to issue environmental protection orders in respect of a release which may cause an adverse impact to the environment. Where possible, a Director may be more inclined to issue an environmental protection order pursuant to s. 102 for a release of a substance which may cause an adverse effect to the environment, instead of proceeding under the sections regarding contaminated sites, which, arguably, require more onerous procedural steps.

Also of concern to the oil and gas industry is the fact that the *AEPEA* provides for joint and several liability and, pursuant to the various definitions of person responsible, owner, registered owner and person responsible for a contaminated site, throws a net of liability over a wide variety of persons. Caught by that net are persons who manufactured, treated, sold, handled, used, stored or disposed, transported or displayed a substance which has had or may have an adverse impact on the environment. The *AEPEA* also provides for a significant increase in the maximum fines which may be levied and for terms of imprisonment in certain situations.

2. Regulations

a. *Experimental Oil Sands Royalty Regulation*, Alta. Reg. 347/92. (Filed November 19, 1992)

This regulation, made pursuant to the *Mines and Minerals Act*,[32] provides for a reduced royalty to be paid upon oil sands or products produced from an "experimental project" as such term is defined in the *Oil Sands Conservation Act*.[33] In replacing Alta. Reg. 287/77, this regulation reduces the minimum royalty that is payable on oil sands or products from experimental projects from 5% to 1%.[34]

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32 *Supra* note 24.

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

34 *Ibid.* s. 2(1)(b).

b. *Horizontal Re-entry Well Royalty Reduction Regulation*, Alta. Reg. 348/92. (Filed November 19, 1992)

This regulation, made pursuant to the *Mines and Minerals Act*,[35] provides for reduced Crown royalty on the incremental production of crude oil or oil sands recovered from the horizontal extension of an existing well. To be eligible, a well must have been extended by continuous drilling operations commenced after September 30, 1992, the well must have been spudded at least 5 years prior to the commencement of the horizontal extension operation and the well must have produced crude oil or oil sands in at least 12 months of the "maintenance period." The "maintenance period" is a period which varies in length between four and five years immediately prior to the horizontal extension of a well.[36]

c. *Low Productivity Well Royalty Reduction Regulation*, Alta. Reg. 350/92. (Filed November 19, 1992)

This regulation, made pursuant to the *Mines and Minerals Act*,[37] provides for the reduction of Crown royalty on crude oil or oil sands from wells which produce at low rates during defined "qualify periods" of either twelve consecutive months ending in the period September to December, 1992 or 24 consecutive months ending on or after January 1, 1993.[38] A qualifying well may produce no more than 121 cubic metres of crude oil or oil sands in any month of the qualifying period, may produce no more than an average of 73 cubic metres^3 per month of crude oil or oil sands in the last six months of the qualifying period, but must have produced in at least six months of the qualifying period.[39] The reduced rate of the Crown royalty for an eligible low productivity well is 5%.[40]

d. *Petroleum Royalty Amendment Regulation*, Alta. Reg. 66/92. (Filed February 13, 1992)

This regulation, made pursuant to the *Mines and Minerals Act*,[41] amends the *Petroleum Royalty Regulation*[42] by creating therein a new provision, s. 11.1. Section 11.1 provides that where a royalty payor subject to an enhanced oil recovery scheme approved pursuant to s. 11 of the *Petroleum Royalty Regulation*[43] has obtained relief from royalty in excess of that level of relief approved by the Minister, such royalty payor shall pay the excess royalty relief to the Crown. The amount of any outstanding excess royalty relief shall bear interest at prime plus one percent until paid. Because enhanced oil recovery scheme royalty relief relies upon estimates of royalty relief followed much later by

35 *Supra* note 24.
36 Alta. Reg. 348/92, s. (1)(j).
37 *Supra* note 24.
38 *Ibid.* s. 2(2).
39 *Ibid.* s. 2(1).
40 *Ibid.* s. 3(1).
41 *Supra* note 24.
42 Alta. Reg. 248/90.
43 *Ibid.*

recalculations of the actual royalty relief obtained, this regulation is rather technical. A detailed explanation of it is beyond the scope of this discussion.

e. *Reactivated Well Royalty Exemption Regulation*,
Alta. Reg. 352/92. (Filed November 19, 1992)

This regulation, made pursuant to the *Mines and Minerals Act*,[44] provides for an exemption from Crown royalty upon the first 8,000 cubic metres of production of crude oil or oil sands from a reactivated well. A "reactivated well" is a well which has not produced any substance except excluded production during the "qualifying period" of either twelve consecutive months, if the well is reactivated during the period of October, 1992 through January, 1993, or 24 consecutive months, if the well is reactivated on February 1, 1993 or later.[45] "Excluded production" is an isolated occurrence of production from the well during the qualifying period which in the opinion of the Minister is consistent with a well test.[46] If this deemed well test production were not classified as "excluded production" the clock on the qualifying period would have to be re-wound.

f. *Reactivated Well Incentive Amendment Regulation*,
Alta. Reg. 353/92. (Filed November 19, 1992)

This regulation, made pursuant to the *Mines and Minerals Act*,[47] amends the *Reactivated Well Incentive Regulation*[48] by including therein a provision for "excluded production" that is virtually identical to that provided in Alta. Reg. 352/92 as noted above. Before this amendment a well that was production tested for the purposes of evaluating its suitability as a reactivation candidate would be disqualified from the incentive provided by the *Reactivated Well Incentive Regulation*.[49]

g. *Horizontal Well Petroleum Royalty Amendment Regulation*,
Alta. Reg. 17/93. (Filed January 20, 1993)

This regulation, made under the *Mines and Minerals Act*,[50] extends the *Horizontal Well Petroleum Royalty Regulation*[51] by extending the period for the drilling of such wells from January 1, 1993 to April 1, 1994.

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44 *Supra* note 24.
45 *Ibid.* ss. 2(2) and (3).
46 *Ibid.* s. 5.
47 *Ibid.*
48 Alta. Reg. 404/91.
49 *Ibid.*
50 *Supra* note 24.
51 Alta. Reg. 96/91.

h. *Natural Gas Royalty Amendment Regulation*,
Alta. Reg. 18/93. (Filed January 20, 1993)

This regulation, made under the *Mines and Minerals Act*,[52] amends the *Natural Gas Royalty Regulation* by lowering the base rate for both New Gas and Old Gas to 15%, increasing price sensitivity of the marginal royalty rate and reducing the gas royalty cap to 35% on Old Gas.

i. *Petroleum Royalty Amendment Regulation*,
Alta. Reg. 19/93. (Filed January 20, 1993)

This regulation, made under the *Mines and Minerals Act*,[53] amends the *Petroleum Royalty Regulation*[54] by introducing separate par prices for light/medium and heavy oil and introduces a new third class of royalty called a "third tier oil royalty" which has royalty rates approximately one third below those for New Oil. The royalty rate for third tier oil is capped at 25% and has a twelve month royalty holiday for exploratory wells, subject to a $1,000,000 cap. With respect to New Oil, the base rate is lowered, the marginal rate is more price sensitive and the oil royalty cap is retained at 30%. With respect to Old Oil, the base rate is lowered to 10% and the oil royalty cap is reduced to 35%.

j. *Third Tier Exploratory Well Royalty Exemption Regulation*,
Alta. Reg. 16/93. (Filed January 20, 1993)

This regulation, made under the *Mines and Minerals Act*,[55] provides a royalty holiday for the drilling of an exploratory well which is classified by the Energy Resources Conservation Board ("ERCB") as a "new field wildcat well", a "new pool wildcat well" or a "deeper pool test well." To be eligible, a well must have spudded or commenced deepening after September 30, 1992. The royalty holiday applicable to such wells is for the first twelve months that oil is obtained from the well or up to a cap of $1,000,000, whichever occurs first.

k. *Nova Joint Hearing Regulation*,
Alta. Reg. 98/93. (Filed April 14, 1993)

This regulation, made under the *Nova Corporation of Alberta Act*,[56] provides for the joint hearing and determination of matters relating to ss. 37(2) and 40(1) of the Act by the ERCB and Public Utilities Board ("PUB") if these boards deem such a course of action advisable.

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52 *Supra* note 24.
53 *Supra* note 24.
54 Alta. Reg. 248/90.
55 *Supra* note 24.
56 R.S.A. 1980, c. N-12.

l. *Oil and Gas Conservation Amendment Regulation*,
Alta. Reg. 9/93. (Filed January 12, 1993)

This regulation, made pursuant to the *Oil and Gas Conservation Act*,[57] concerns changes to the procedure for transferring well licences and naming wells. Of note is the change to s. 2.050(1) which makes the transfer of a well licence subject to the approval of the ERCB.[58] (The repealed provision suggested a well licence transfer would be automatic upon payment of the prescribed fee.)

m. *Pipeline Amendment Regulation*,
Alta. Reg. 148/92. (Filed April 27, 1992)

This regulation, made under the *Pipeline Act*,[59] made extensive amendments to the *Pipeline Regulation*.[60] In particular the regulation varies the requirements for applications for certain permits, varies standards for materials and construction of certain facilities and creates new rules in respect of the emergency procedures to be established for pipelines in sour service or those transporting HVP liquids.

3. Evolving Matters

a. *Alberta Crown Royalty Regime Restructuring*

On October 13, 1992 the Alberta Department of Energy announced extensive changes to the royalty regime relating to the production of Alberta Crown petroleum and natural gas. Many of the more significant changes have been summarized in this paper in the discussion of the Alberta Regulations which were filed November 19, 1992 pursuant to the *Mines and Minerals Act*.[61] The overhaul of the Crown royalty regime was an attempt by the government of Alberta to respond to changes in the oil and gas industry in the province which have occurred since 1973 when the last significant restructuring of the Crown royalty regime was conducted.

The Western Canadian Sedimentary Basin is considered a "mature" basin because of the extensive exploration and production activities which have been conducted in it. Production from existing pools is declining and operating costs per unit of production are increasing as operators seek to produce remaining reserves from oil pools through the use of advanced technology. New pool discoveries in Alberta tend to be smaller than in the past while costs of exploration and production have generally risen. Hydrocarbon market prices have not kept pace with the rosy forecasts of the 1970s and 1980s which had been made by industry and government analysts alike.

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57 R.S.A. 1980, c. O-5.
58 *Ibid.* s. 2(a).
59 R.S.A. 1980, c. P-8.
60 Alta. Reg. 122/87.
61 *Supra* note 24.

Generally speaking, the changes to the Crown royalty regime result in reductions in the royalty that is payable by the industry. In particular, royalty incentives are offered for the application of new technology (such as horizontal drilling) as well as to encourage the more complete exploitation of mature pools through well reactivation and development drilling strategies.

In addition to the payment of the Crown royalty, the calculation and administration of the Crown royalty has become a significant burden to the industry, particularly in the instance of natural gas royalty. In addition to generally lower rates of Crown royalty, it is the expressed intent of the government to simplify the complex structure of natural gas royalty. This in turn should reduce the administration costs for industry and government alike.

The October 13, 1992 announcements were a significant step in the royalty restructuring process. Further announcements are expected, particularly with respect to the restructuring of the natural gas royalty and perhaps to fine tune regulatory changes made pursuant to the original announcements.

b. *Clean Air Strategy for Alberta*

The Province of Alberta has struck a task force which will consider Goal K of Alberta's Clean Air Strategy. The initial task force report on the clean air strategy for Alberta had made a number of recommendations regarding Goal K as follows:

> Improve the gathering, sharing, integration and application and scientific technical knowledge and research regarding atmospheric processes and effects on health and ecosystems.

The three objectives identified in the Clean Air Strategy for Alberta are as follows:

K-1 Identify more consistent and readily detectable adverse effects on ecosystems, human and animal health and physiological adaption resulting from changes in ambient air quality. Correlate these effects with levels of exposure and thresholds of effect. Priority should be given to the most sensitive receptors and the largest sources.

K-2 Review and develop a series of environmental indicators that are representative and indicative of human environmental health and which are understandable for reporting on air quality management progress.

K-3 Undertake research and technology development activities in support of clean air goals.

C. BRITISH COLUMBIA LEGISLATION

1. Legislation

a. *Mineral Land Tax Amendment Act, 1992,* S.B.C. 1992, c. 13.
(Section 4 effective January 1, 1992, most other sections effective December 21, 1992, remaining sections effective on proclamation)

The most significant change brought about by this statute is the amendment to the *Petroleum and Natural Gas Act*[62] to provide for a Freehold Production Tax by freehold land owners. The rate of this tax is to be prescribed by regulation[63] and shall not exceed 30% of the value of the petroleum and natural gas produced and disposed of from the freehold land.

b. *Energy Council Act,* S.B.C. 1992, c. 5. (Effective on proclamation)

This statute provides for the creation of the British Columbia Energy Council. The Council is to prepare and submit a "provincial energy plan ... to assist in developing British Columbia energy policies."[64] Fees may be levied against public utilities in British Columbia to recover the expenses related to the operation of the Council.

c. *Commissioner on Resources and Environment Act,* S.B.C. 1992, c. 34.
(Effective on proclamation)

Pursuant to this Act, the Commissioner of Resources and Environment shall be appointed by the Lt. Governor-in-Council. The term of the appointment is to last for five years and the Commissioner's role is to advise the executive council "in an independent manner" on land use and related resource and environmental issues in British Columbia. The Commissioner may also make a report to the public on land use and related resource and environmental issues in British Columbia and the need for legislation, policies or practices respecting these issues if the Commissioner believes that it is in the public's interest to do so.

The mandate of the Commissioner is to develop a wide strategy for land use and related resource and environmental management within British Columbia. The development of that program will include the development of regional planning processes, community based participatory processes regarding land use, resources and environmental management and a dispute resolution system for land use and related resource and environmental issues in British Columbia. The Act specifically provides for the Commissioner to consider economic, environmental and societal interests, local, provincial and federal government responsibilities and the interests of aboriginal peoples.

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62 R.S.B.C. 1979, c. 323.

63 See B.C. Reg. 495/92 (discussed in the following section of this paper).

64 *Energy Council Act,* S.B.C. 1992, c. 5, s. 6(1)(a).

The Act also gives the Commissioner the authority to conduct hearings to carry out the purposes of the Act but does not entitle any person to require the Commissioner to hold a hearing.

2. Regulations

a. B.C. Reg. 62/92 (Deposited March 13, 1992)

This regulation, made pursuant to the *Petroleum and Natural Gas Act*,[65] provides for the extension of a Petroleum and Natural Gas licence beyond its original term if the drilling of a well on the licenced lands has been delayed pending completion of an environmental or socioeconomic study, a public hearing, or an investigation. The extension granted must be the lesser of the number of years nearest the period of delay or three years.

b. B.C. Reg. 66/92 (Deposited March 18, 1992)

This regulation, made pursuant to the *Pipeline Act*,[66] varies the *Pipeline Regulations*[67] by incorporating new standards for pipeline crossings of highways, utility lines or other pipelines.

c. B.C. Reg. 419/92 (Deposited October 29, 1992)

This regulation, made pursuant to the *Petroleum and Natural Gas Act*,[68] varies the *Drilling and Production Regulation*.[69] The first change made by this regulation is to the terms of the drilling deposit to be tendered by any operator in conjunction with a well application as security to insure the proper conduct of operations, abandonment and site reclamation in respect of the well. This drilling deposit is refundable if the well application is not granted or if a certificate of restoration is issued following abandonment and reclamation.

More significant perhaps is the second change this regulation makes to the *Drilling and Production Regulation*[70] in respect of persons who may now be ordered to abandon, plug or restore a well. As amended, s. 47(2) of the regulation now provides that any other person who, in the opinion of the division head with the Ministry of Energy, Mines and Petroleum Resources, has an interest in the well, including a trustee in bankruptcy, a receiver or a receiver-manager may be ordered to abandon, plug or restore a well. The regulation formerly applied only to owners or operators.

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65 *Supra* note 62.

66 R.S.B.C. 1979, c. 328.

67 B.C. Reg. 451/59.

68 *Supra* note 62.

69 B.C. Reg. 336/91.

70 *Ibid.*

d. B.C. Reg. 495/92 *Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation* (Deposited December 18, 1992)

This regulation, made pursuant to the *Petroleum and Natural Gas Act*,[71] replaces the *Petroleum and Natural Gas Royalty Regulation*[72] which is repealed. The most significant changes in the regulation relate to the imposition of the Freehold Production Tax as described above.[73]

3. Evolving Matters

a. Environmental Action Plan

The Province of British Columbia is currently undergoing a comprehensive review of its environmental legislation. That review has led to a variety of initiatives in regard to the British Columbia Environmental Assessment and Environmental Protection regulatory regimes. The Minister of Environment, Lands and Parks released an environmental action plan which outlined the Province's environmental priorities. The province's identified priorities are:

1. Improving environmental impact assessment;
2. Preserving biodiversity in natural areas;
3. Reducing waste and preventing pollution;
4. Improving water management; and
5. Strengthening enforcement and compliance.

As part of the action plan, the Ministry of Environment, Lands and Parks has committed the government to revising all environmental protection legislation in the Province of British Columbia. The Ministry proposed that all of the ministries and environmental programs be consolidated into four new acts:

1. *The British Columbia Environmental Protection Act*;
2. *The Wildlife, Fish and Endangered Species Act;*
3. *The British Columbia Environmental Assessment Act;* and
4. *The British Columbia Water Management Act.*

The respective purposes of those four Acts are as follows:

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71 *Supra* note 62.

72 B.C. Reg. 222/88.

73 *Mineral Land Tax Amendment Act 1992*, S.B.C. 1992, c. 13, s. 17.

The *British Columbia Environmental Protection Act* ("*BCEPA*") will be the major environmental protection act of the Ministry. It will group together the provisions that apply to all environmental legislation — such as the general principles of environmental management, enforcement, environmental rights and obligations, appeals and emergency measures. As well, the *BCEPA* will establish a legislative basis for programs related to pollution prevention and control, air quality, water quality, pesticides and waste management.

The *Wildlife, Fish and Endangered Species Act* ("*WFESP*") will encompass all programs concerned with managing and enhancing wildlife, fish and habitat of endangered species. This Act will be a major environmental statute and it will provide for many new approaches and programs on species production, biodiversity and wildlife enhancement.

The *British Columbia Environmental Assessment Act* ("*BCEAA*") will contain all measures related to environmental impact assessment. It will incorporate modern ideas and procedures on this subject, and combine the current assessment processes into one integrated system. Of particular concern will be the scope and application of environmental assessment to all activities and developments with significant environmental impacts. Care will also be taken to ensure co-operation and efficiency between jurisdictions.

The *British Columbia Water Management Act* ("*BCWMA*") will consolidate all provisions dealing with the effective management of water. This will include groundwater protection, instream flow protection, water management planning and water export.

The goal of the government is to introduce all legislation above within the first term of the government. The government is also committed to public consultation in regard to the legislation.

b. Environmental Assessment in British Columbia

The Minister of Environment, Lands and Parks issued a report on the consultation process regarding environmental assessment in British Columbia in July 1992.[74] The report made a number of recommendations regarding the British Columbia environmental process. Those recommendations are summarized as follows:

(i) *Application of the Environmental Assessment Process*

The report recommended that the environmental assessment process be applied consistently to all projects. The recommendation is that environmental assessment apply to a broad range of private and public sector initiatives which include forest activities, urban development, oil and gas exploration, placer mining, aquaculture operations, agricultural activities and major highway development. While according to the report, the

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[74] British Columbia, *Reforming Environmental Assessment in British Columbia: A Report on the Consultation Process* by D. Lovick, Parliamentary Secretary to the Minsiter of Environment, Lands and Parks, (Victoria: Queen's Printer, July 1992).

environmental impacts of these activities are currently considered through a variety of referral and planning processes, the report further states that the current processes do not provide consistent, open and effective means of identifying and managing environmental impacts. The report recommends that the new environmental legislation require assessment through the three existing project review processes.

The current review process is through the Energy Project Review Process, the Mine Development Assessment Process and the Major Project Review Process. The report recommends that there be a single legislative environmental assessment process.

(ii) *Scope of Environmental Assessment*

The report recommends that in regard to the scope of environmental assessment for each project, each assessment should include both social and environmental justification. The report also recommends that the financial justification analysis of a private sector project should only be required if the proponent is seeking public funding or if significant Crown owned resources are involved. Such a recommendation would encompass oil and gas activities (if the project is a "major" project).

(iii) *Administration of the Environmental Assessment Process*

Just as the assessment of environment impacts related to the energy industry in Alberta was hotly debated, with ultimately the ERCB retaining jurisdiction, the Province of British Columbia has also considered this issue and has recommended that a neutral agency be created to administer the environmental assessment process. The report states:

> The agency should coordinate the preparation of an integrated evaluation of the environmental, social and economic impacts of a project, to determine whether a project approval certificate should be issued. Responsibility for the technical and scientific review of a project should remain with line ministries.[75]

Thus, while the technical review of an oil and gas project would remain with the Minister of Energy, Mines and Petroleum Resources, the integrated evaluation of the project would lie with the neutral agency.

(iv) *Decision Making*

The report recommends that decisions on conditions of permits and licenses all be subject to appeal if they were not addressed during the environmental assessment process.

(v) *Extending Partnerships*

The report recommends that the assessment legislation include provisions which would define "equivalency criteria" to enable the integration of federal, provincial, local and first nation involvement in the assessment process.

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75 *Ibid.* at ix.

(vi) *Public Involvement*

The report recommends that the legislation provide ample opportunity for participation in the environmental assessment process at all stages of the process. It recommends that specific time frames for public involvement should be established to provide a certainty of process with regard to public involvement. It also recommends that participant assistance be encouraged. While participant assistance is not discussed, it will likely involve some form of intervenor funding which has become an accepted part of the environmental assessment process and was, in some senses, endorsed in the Old Man Dam Supreme Court decision.[76]

c. Discussion Paper on Environmental Protection in British Columbia

The Ministry of Environment, Lands and Parks for the Province of British Columbia issued a discussion paper on new approaches to environmental protection in British Columbia.[77] That document provides a discussion basis for proposed environmental protection legislation in the province and a list of recommendations and general principles upon which the proposed legislation is to be based. Most notable of those principles is the "zero pollution" objective. The discussion provides as follows:

> The *BCEPA* should make "zero pollution" of the environment an explicit goal of the Ministry. Legislative provisions should allow the Minister to set targets and deadlines for the reduction of certain pollutants such as municipal solid waste, and for the elimination of certain toxic chemicals designated by regulation.[78]

A zero discharge policy will have a significant impact on the oil and gas industry with regard to its operations.

D. SASKATCHEWAN LEGISLATION

1. Statutes

a. *Crown Minerals Amendment Act, 1992*,
S.S. 1992, c. 25. (Effective date varies by section)

This Act amends the *Crown Minerals Act*,[79] by defining "mineral" so that it no longer includes sand or gravel. Another amendment allows the Lieutenant Governor-in-Council to make regulations which exempts any disposition or sales of Crown minerals owned by Crown corporations from the Act. Another amendment gives the Lieutenant Governor-in-Council the power to set aside and transfer administration and control of Crown minerals

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76 *Friends of the Oldman River Society* v. *Canada (Minister of Transport)*, [1992] 1 S.C.R. 3.

77 British Columbia, Ministry of Environment, Lands and Parks, *New Approaches to Environmental Protection in British Columbia: A Legislation Discussion Paper* (Victoria: Queen's Printer, 1992).

78 *Ibid.* at 14.

79 S.S. 1984-85-86, c. C-50.2.

and Crown mineral lands to Her Majesty the Queen in Right of Canada, to satisfy or discharge obligations to Indian Bands in Saskatchewan.

Section 10.1 was amended to allow for a cancellation of all or a portion of a Crown disposition if it has been determined that the development should not proceed after an environmental assessment and review conducted under *The Environmental Assessment Act.*[80] Section 10.1 also provides for compensation to the holder of a Crown disposition upon a cancellation of a parcel or cancellation of a Crown disposition.

Section 16.1 has been amended to provide for a deep rights reversion process which is similar to that currently in force in Alberta. Section 23.01 provides that a person entitled to compensation for oil and gas rights which were returned to the Crown under the *Oil and Gas Conservation, Stabilization and Development Act*[81] is solely responsible for paying amounts outstanding with respect to encumbrance holders who were on title prior to December 10, 1973 and that the Crown is not responsible for paying any amounts with respect to such encumbrances. Encumbrance holders are limited to a $10,000 ceiling per production year with respect to their encumbrance and upon transfer by an encumbrance holder, the entitlement to compensation is extinguished. Section 27.1 is a new provision which states that if in the opinion of the Minister, the liability for royalty payments under the Act is artificially or unduly reduced pursuant to an agreement or arrangement, the Minister may calculate the royalty as if such agreement or arrangement had not occurred. Section 27.2 defines "space" as "space occupied or formerly occupied by a Crown mineral" and states that such spaces are the property of the Crown, remain the property of the Crown and that the Crown has the right to lease the spaces. This amendment relates to the increased demand for gas storage spaces.

b. *Mineral Taxation Amendment Act 1992,*
S.S. 1992, c. 9. (Effective June 3, 1992)

This Act amends *The Mineral Taxation Act,* (1983) by increasing mineral tax on fee simple owners from $640.00 per year to $960.00 per year.

c. *The SaskEnergy Act,* S.S. 1992, c. 5-35.1.
(Section 59 effective November 1, 1992, all other sections effective October 5, 1992)

This Act provides for the continuation of the amalgamated corporation of SaskEnergy Incorporated and Saskatchewan Energy Holdings Ltd. as SaskEnergy Incorporated, that SaskEnergy shall not have any share capital or issue any shares and that the *Business Corporations Act (Saskatchewan)*[82] does not apply to SaskEnergy. SaskEnergy is an agent of the Crown and has the power to purchase, distribute, sell, manufacture, produce, transport, gather, compress, process and store gas and all other activities necessarily incidental thereto. Section 23 gives SaskEnergy the exclusive right to "distribute" gas in and through any area in Saskatchewan. "Distribution of Gas" is the "movement of gas by

80 S.S. 1978-80, c. E-10.1.
81 R.S.S. 1978, c. O-2.
82 R.S.S. 1978, c. B-10.

means of all gas pipeline facilities downstream of the outlet of the shut-off valves of high pressure gas transmission pipelines at stations where pressure reduction first occurs for eventual delivery of gas to consumers of gas in Saskatchewan." The Corporation may consent to the distribution of gas in Saskatchewan by other persons.

Section 60 provides that TransGas Limited is given the exclusive right to "transport" gas in and through any area in Saskatchewan. "Transportation of gas" means the movement of gas by means of all gas pipeline and compression facilities, where that movement is:

(a) downstream of the point where physical possession of that gas is transferred to a high pressure gas transmission line from a low pressure gas gathering system or an interconnected interprovincial gas transmission pipeline; and

(b) upstream of:

(i) the outlet to the shut-off valves of high pressure gas transmission pipelines at stations where pressure reduction first occurs for eventual delivery of gas to consumers of gas in Saskatchewan; or

(ii) the point where physical possession of gas is transferred to an interconnected interprovincial gas transmission pipeline or a direct purchase customer of gas in Saskatchewan who takes delivery of the gas at high pressure.

Other Acts have also been amended where necessary to give effect to the foregoing rights to distribute and transport gas.

d. *Land Titles Amendment Act, No. 2, 1992*, S.S. 1992, c. 58.
(Sections 41 to 48 and 52 effective December 1, 1992, remaining sections effective on proclamation)

This Act amends *The Lands Titles Act*,[83] by providing for a new form of mortgage to be executed, which form will incorporate at least one of three sets of mortgage terms. At or before the time the mortgage is executed, the mortgagee must provide the mortgagor with a true copy of the mortgage terms together with a statement of any additions, amendments and deletions thereto and obtaining acknowledgement from the mortgagors that they have received the same.

e. *The Clean Air Amendment Act*, S.S. 1992, c. 22. (Effective July 31, 1992)

This amendment, in part, provides that if a person is issued a control order and that person fails to comply with the order in the time specified, the Minister may carry out the activities required by the control order and recover the costs and expenses from that person. The Crown may recover the cost by filing a certificate with the local registrar of

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[83] R.S.S. 1978, c. L-5.

the Court of Queen's Bench in the judicial centre nearest to the place where the work was performed. The certificate has the same effect as a judgment issued by the Court of Queen's Bench. The amendment also provides the additional regulatory authority to the Minister of the Environment to classify industrial sources and fuel burning equipment on the basis of the amount of emissions and air contaminants produced from their operation and to prescribe fees or a sliding scale of fees for permits based on the classification. Basically, these regulatory powers permit the Minister of the Environment to develop market based incentives for pollution protection.

f. *Environmental Management and Protection Amendment Act*, S.S. 1992, c. 49. (Effective August 24, 1992)

This amendment includes additional definitions for "waste dangerous goods", provides for access and entry rights to environment officers and search warrant rights to assist in the exercise of such rights of entry. Amendments to s. 34.1 of the *Environmental Management and Protection Act*[84] provide that no person shall pollute or cause any pollution. An amendment to s. 35 provides that any resident of Saskatchewan who is at least 18 years of age and who believes an offence has been committed under the Act may apply for an investigation to be conducted by filing a solemn declaration that states his or her name, the nature of the alleged offence and a concise statement of the evidence supporting the opinion.

g. *Pest Control Products (Saskatchewan) Amendment Act, 1992*, S.S. 1992, c. 33. (Effective on proclamation)

This amendment provides that no person shall carry on a business involving the sale, use or application of a pesticide or apply a pesticide without a license, subject to s. 39 of the *Environmental Management and Protection Act.*[85] All existing permits issued under the *Pest Control Products (Saskatchewan) Act*[86] are continued.

2. Regulations

a. *The Petroleum and Natural Gas Amendment Regulations, 1992 (No.3)*, Sask. Reg. 68/92

The *Petroleum and Natural Gas Amendment Regulations*,[87] were amended so that an "infill well" which is a development well drilled after May 16, 1992 shall receive a royalty tax holiday which is based upon either a one year period or on the first 1500 cubic metres of oil produced from such infill well.

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84 S.S. 1983-84, c. E-10.2.

85 *Ibid.*

86 R.S.S. 1978, c. P-8.

87 Sask. Reg. 8/69.

b. *The Freehold Oil and Gas Production Tax Act, Amendment Regulations, 1992*, Sask. Reg. 69/92

Amendments were made to the *Freehold Oil and Gas Production Tax Act*[88] to mirror those changes which were made for infill wells as discussed above.

3. Evolving Matters

a. Bill 33, *An Act respecting Security Interests in Personal Property and making Consequential and Related amendments to Certain Other Acts*, 3d Sess., 22nd Leg., Saskatchewan, 1993. (Second Reading, April 22, 1992)

This Act will replace the *Personal Property Security Act.*[89] With respect to oil and gas matters, a significant change will be that the validity, perfection and effect of perfection or non-perfection of a security interest in minerals or in accounts resulting from the sale of minerals will, under the new act, be governed by the law of the jurisdiction in which the minehead (wellhead) is located. Previously, the governing law relating to a security interest in an intangible was that of the jurisdiction where the debtor was located when the security interest attached.

b. Bill 44 of 1993, *An Act respecting the Inspection of Gas Installations and Gas Equipment*, 3d Sess., 22nd Leg., Saskatchewan, 1993.

This Act will provide for the inspection and installation of all gas installations and gas equipment and provide that all gas installations shall conform to all regulations. Where gas installation and gas equipment is involved in an accident which results in the death or injury of a person, a fire or an explosion, the owner or their representative must notify the authorities giving details of such accident and allow the Chief Inspector to investigate the cause of such accident.

c. *Saskatchewan Department of Environment and Resource Management (Policies)*

The Charter of Environmental Rights which was proposed in Saskatchewan died on the order paper and is not likely to be revived in view of the province's current economic situation. There has also been a shift in policy relating to hydrocarbon air emissions which is likely to make land farming of contaminated soil more difficult. An environmental liability task force has been established by the province to consider responsibility for contaminated sites within the province. The Manitou Sand Hills Park has been created encompassing 64,000 acres. Whether any oil and gas activity will be allowed in the park is uncertain at this time. Finally, there are also proposed changes to the oilfield storage regulations which may impact the industry but which have not as yet been formulated into official regulations.

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88 S.S. 1982-83, c. F-22.1.

89 S.S. 1979-80, c. P-6.1.

II. REGULATORY DEVELOPMENTS

A. FEDERAL

1. National Energy Board

a. Decisions

(i) *GHW-1-91 Proposed Changes to the Application of the Market-Based Procedure*

The long awaited decision on the National Energy Board's ("NEB" or "Board") proposed changes to its Market-Based Procedure ("MBP")was released in Reasons for Decision dated May, 1992. It is a status quo decision.

In its Reasons for Decision, the NEB decided not to change the Complaints Procedure component of the MBP, despite the fact that several Canadian domestic interests had maintained that under the current structure of the MBP it was not an effective vehicle to protect their interests. The Board concluded that the Complaints Procedure was a reasonable method to continue to fulfill its statutory mandate with regard to proposed gas exports being surplus to reasonably foreseeable Canadian requirements. The Board reiterated its position that it will exercise its judgment on a case-by-case basis when assessing whether or not a domestic interest was able to acquire gas on similar terms and conditions to those contained in an export contract. The Board indicated that a complainant would have the onus of supporting its case. If the Board finds that a complaint has merit, the onus will be on the export applicant to demonstrate why its licence should be granted in the face of such a valid complaint.

The most interesting aspect of this review was the Board's proposed changes to the "other public interest considerations" component of the MBP. As part of its August 14, 1991 proposal the Board had indicated that it was prepared to relax its assessment of matters such as: (i) the likelihood that contracted volumes would be taken; (ii) an assessment of the durability of the Export Sales Contracts; and (iii) whether or not the Export Sales Contracts were negotiated at arms-length.

In the supporting information provided with the referenced letter the Board outlined its rationale for no longer continuing to apply these criteria to its Export Licence Applications. However, a number of parties were reluctant to see the Board back away from these requirements *at this time*, although they supported such action in principle. The Board decided to leave the existing requirements in place.

One area in which the Board did confirm a flexible approach relates to the gas supply underpinning an Export Licence Application. The Board indicated that while it will continue to expect an Export Licence to be underpinned by established reserves for the full term-volume, it will be prepared to place less emphasis on the level of productive capacity underpinning the licence, as long as it covers a majority of the term.

(ii) *GH-R-1-92 TransCanada Pipelines Limited ("TransCanada") Blackhorse Extension Review*

In Reasons for Decision dated June, 1992, the NEB decided to reverse its previous Decision (GH-1-91) to deny authorization to TransCanada to construct the Blackhorse Extension, which is designed to connect with a new pipeline (the Empire State Pipeline) approved for construction in New York State. The Board had originally denied this Application, as it found that other alternatives, notably Tennessee Gas Pipeline Company's proposal to utilize expanded facilities on the existing Niagara line, would be less costly and more environmentally acceptable. However, based on the evidence presented during the review proceedings the Board found that new facts and changed circumstances warranted a setting aside of its original Decision.

This Decision is important from a policy point of view in that it provides insight into the Board's review process and gives some indication of the type of information the Board will view as being persuasive when attempting to have it re-examine and reverse an earlier decision. When the Board is faced with an application to review a decision, the first hurdle the applicant must overcome is to persuade the Board that its original decision should be reviewed. The NEB's Rules of Practice and Procedure set out the grounds required in order for an applicant to successfully satisfy this requirement. In Blackhorse, as a basis for its decision to conduct the review, the Board relied principally on the fact that the U.S. Federal Energy Regulatory Commission ("FERC") had approved the Empire State Pipeline, while denying the other alternatives put forward by a variety of parties in order to accommodate the delivery of these volumes to market. Concern was expressed with the possibility that the NEB would rely on a subsequent FERC decision to justify a review of an NEB decision. In fact, this particular decision has already been identified by at least one party, the Industrial Gas Users Association, as forming a basis to once again challenge the NEB's "rolled-in" approach to tolling. This party is citing the FERC's decision with regard to incremental tolling on Great Lakes, as a sufficient basis for the Board to review its past tolling Decisions.

In its Reasons for Decision, the NEB was careful in how it handled the FERC decision as a consideration in justifying the reversal of its previous decision. The Board noted that the alternative proposals previously envisaged by the Board as being available had now been rejected and, therefore, no longer existed. Additionally, the Board found that even if applications relating to the alternative proposals were refiled with the proper authorities they would not be able to satisfy the market demand in a timely fashion. As well, the Board found that the evidence presented clearly indicated that the parties involved were not interested in utilizing the facilities provided by these alternatives, as they did not satisfy their requirements — namely an independent, alternative source of gas supply and transportation. Finally, the Board acknowledged that despite its conclusion in the original Decision that there was no indication that any party would be unduly adversely affected by the denial of the proposed Blackhorse facilities, in reality, sales of Canadian natural gas had been lost, reduced and/or delayed as a result of the Board's Decision. The Board stated clearly that it was a combination of these factors that persuaded it to reverse its original Decision.

(iii) *GH-R-1-91 Canadian Petroleum Association —Review of GH-5-88 Decision Alberta and Southern Gas Co. Ltd. Export Licence Extension*

In Reasons for Decision dated June, 1992, the Board confirmed and strengthened the interim measures it had put in place on February 4, 1992 (see report in last year's "Regulatory Developments") to counteract the detrimental effects on long term Alberta and Southern Gas Co. Ltd. ("A&S") gas sales by the California Public Utilities Commission ("CPUC"). The Board found that the Canadian public interest had been adversely affected by the CPUC's decision. While this was the fundamental finding, other items contributed to the Board's reasoning. The Board characterized the CPUC's actions as an attempt to extend its jurisdiction beyond the boundaries of the State of California and into matters within the NEB's mandate. The Board also looked to the impact the CPUC's actions would have on the financial investments Canadian producers had made based on the NEB's Decision to approve an extension to the A&S Export Licence. The Board found that the CPUC's actions effectively undermined the contractual basis upon which these investments were made and adversely affected their economic viability.

In dealing with this issue, the Board adopted a "double barrel" approach, curtailing both short-term exports, which would displace existing A&S sales into Northern California, as well as interruptible transportation on the Alberta Natural Gas Company Ltd. ("ANG") pipeline (this meshes with provincial action restricting interruptible service on NOVA). The new Orders add the Huntingdon, B.C. export point to the Kingsgate, B.C. export point covered by the interim measures. The Board indicated that the Orders would remain in effect for an indefinite period, until fair and equitable contractual arrangements could be negotiated by all affected parties and the associated regulatory approvals put in place. The NEB did confirm that its restrictions were directed only at the Northern California market and that exports to either Southern California or the Pacific Northwest could apply to the Board for an exemption and obtain relief from the impact of the Board's Decisions.

Given all that has evolved regarding California/Canadian relations it is not surprising that the NEB has taken the measures implemented by this Decision. There was considerable pressure on the NEB to take a forceful stand which would protect Canadian interests in the face of CPUC actions which are viewed as being detrimental to these interests. Given that the NEB was persuaded to put in place the interim restrictions following a canvassing of the views of Interested Parties and pending the outcome of the subject public hearing, it would have been surprising to see a dramatic change in position, unless the evidence presented clearly indicated that the Board's reasoning was incorrect.

Of particular interest is the analysis conducted by the NEB which led it to the conclusion that circumstances had indeed changed from those existing at the time it decided to extend the A&S Export Licence. This conclusion formed the basis upon which the Board acted as it did. The Board devoted considerable time to a comparison of the policy framework for international gas trade which existed at the time of the GH-5-88 Reasons for Decision with that which confronted the Board at the time of the subject decision. The Board concluded that the position of the CPUC, and its gas procurement policy, were markedly different from the position at the original export licence proceeding. The Board noted that through a series of decisions over the last few years the

CPUC has progressively moved further away from the positions it advanced to the Board as part of the GH-5-88 proceedings, and upon which the Board placed reliance in arriving at its original Decision.

The NEB's Decision is characterized by strong language used to describe the implications of the CPUC's actions. The tone of the Decision is undoubtedly designed to convey the strength of the Board's convictions and indicate clearly to the CPUC that, while the Board would prefer a "market" solution to this problem, it is prepared to exert countervailing regulatory pressure as long as the CPUC persists in its pattern of interfering with commercial arrangements.

As part of the Decision, the NEB explicitly recognized that its actions would effectively constitute the reimposition of the "incrementality test", which was discontinued as part of the deregulation process. This test required that exporters demonstrate that gas sales are truly incremental and would not displace other Canadian gas sales, directly or indirectly. The test was seen as an overhang from the days of strict industry regulation and inconsistent with free market competition. Parties, other than the CPA, acknowledged that to grant the requested Orders might be construed as implementing some form of an incrementality test, but they maintained that, in the circumstances of this case, the Canadian public interest overrode any such concerns and dictated that the Board grant the orders requested. The Board relied on this reasoning in overcoming the negative connotations associated with the incrementality test.

Finally, it is interesting to note a number of procedural matters addressed by the NEB during the preliminary stages of the hearing. The CPA had sought an order seeking that Pacific Gas Transmission Company ("PGT") and Pacific Gas and Electric Company ("PG&E") be compelled to produce evidence in these proceedings. Without concluding that it could not legally take such action, the Board found that such evidence was not necessary and accordingly denied the CPA's request. The CPA also made a request with respect to a Letter of Comment filed by the CPUC. The CPA asked that the CPUC be required to produce witnesses to speak to positions taken in the Letter of Comment or alternatively, that the letter be struck from the record. The CPA maintained that the letter contained significant evidence and unsubstantiated assertions that it wished to cross-examine. The Board declined to take either of the actions requested of it, instead opting to leave the information on the record and deal with it in terms of the weight given to an unsupported document.

(iv) *GHW-1-92 Altamont Gas Transmission Canada Limited ("Altamont Canada")*

In Reasons for Decision dated February 1993, the Board dismissed Altamont Canada's application for an approximately 300 metre "sausage link" pipeline which would connect a new NOVA Corporation of Alberta ("NOVA") lateral (the "Wild Horse mainline") with the proposed Altamont Gas Transmission Company ("Altamont") pipeline in the United States. In its consideration of this Application the Board, at its own initiative, took the unusual step of raising a preliminary question of jurisdiction related to its authority over the proposed Wild Horse mainline.

By asserting its jurisdiction over the upstream facilities, the NEB has raised a series of questions relating to the federal/provincial division of powers, the regulation of the balance of the NOVA system, the status of other provincially regulated entities (such as TransGas Limited — "TransGas") and the fate of current and future "sausage link" pipelines. These issues could substantially affect the current regulatory structure within Canada.

Many questions have already been raised with respect to other implications which flow from the Board's Decision. The Board will be required to exercise its jurisdiction in a consistent and even-handed fashion, and this may lead it to assert jurisdiction over other upstream and downstream facilities (as is already evidenced by the Board's treatment of a small sausage link pipeline — WBI Canadian Limited — which is proposed to connect a new lateral on the TransGas system in Saskatchewan to the Williston Basin system in the U.S. — this Decision could have a corresponding impact on federal/Saskatchewan relations — see report following). Likewise, parallel situations could arise on downstream pipelines, such as the St. Clair Pipeline and its connection to the Union Gas system. This latter situation was specifically cited by Altamont Canada in its previous submissions to the Board.

As well, there are numerous other sausage link pipelines which are currently regulated by the NEB and while in its Reasons for Decision the Board appears to be sending a message that it does not intend to re-examine all of its past Decisions in light of this Decision, it could lead to subsequent changes in the regulatory environment for those existing pipelines upstream of such sausage links. This could be of particular importance given that many of these existing upstream pipelines are regulated on a complaint basis (*i.e.* effectively not actively regulated) and a party could now bring a complaint before the NEB and maintain that the NEB is the appropriate body to resolve the dispute. This Decision could also have a major impact on the commercial structure of future export projects.

The fact that the NEB's Decision contained the dissenting views of two Board Members reflects the sensitivity of the Decision and the difficulty faced by the Board in arriving at a conclusion. While this is not a unique occurrence, it is indeed unusual. The reasoning adopted by both the majority and minority positions applies the same constitutional tests (which have previously been laid down by the Courts) yet the Board members came to opposite conclusions, based on their own views of certain aspects of the facts placed before the Board.

Recent events indicate that a full-blown federal/provincial jurisdictional battle may have been averted. Altamont had appealed the Decision but recently dropped the appeal when NOVA and Altamont announced that a NOVA subsidiary will take over responsibility for pursuing necessary Canadian regulatory approvals for the Canadian portion of the Altamont project. The likely candidate to pursue such regulatory approvals is Foothills Pipe Lines Ltd. which is already under NEB jurisdiction. In this way, a constitutional battle can be avoided as the integrity of provincial jurisdiction over the NOVA system is preserved.

(v) *WBI Canadian Pipeline, Ltd. ("WBI")*

Concurrent with releasing its Reasons for Decision in the Altamont Canada case discussed above, the Board dismissed, again on jurisdictional grounds, a similar application by WBI for authority to construct a 1.15 kilometer "sausage link" pipeline which would connect to an already constructed 35.6 kilometer TransGas line extending from the WBI tie-in to the main TransGas system. Applying reasoning similar to that in the Altamont Canada Decision, the Board concluded that the new TransGas line is integral and essential to the proposed WBI line and that, when these two lines are joined and operations commence, the combined line will be operated as one overall undertaking of an international character. Accordingly, the Board determined that the combined WBI and new TransGas lines will constitute a federal work and undertaking which should properly fall within federal jurisdiction under s. 92(10)(a) of the *Constitution Act, 1867*[90] and should be regulated by the NEB.

TransGas is seeking a review of the Decision failing which it will pursue an appeal to the Federal Court of Canada on grounds, *inter alia*, that it was not given proper notice of the jurisdictional issue and an opportunity to respond thereto. Further, TransGas is arguing that in applying the constitutional tests of jurisdiction, the Board isolated the 35.6 kilometer TransGas segment from the balance of the TransGas system and accordingly failed to have due regard for the integrated nature of the TransGas system.

b. Reports/Workshops

(i) *Natural Gas Market Assessment Long Term Canadian Natural Gas Contracts*

At the end of August 1992, the Board issued a report on "Natural Gas Market Assessment: Long-Term Canadian Natural Gas Contracts" (the "Report") as part of the ongoing monitoring of the Canadian natural gas market which the NEB conducts in conjunction with its "Markets-Based Procedure" to ensure that natural gas licenced for export is surplus to reasonably foreseeable Canadian requirements. Previous Natural Gas Market Assessment Reports published in 1988 and 1989 addressed the overall structure and functioning of the natural gas market while the Report focuses on developing trends in long-term Canadian contracting practices governing the sale of Western Canadian gas to domestic and export markets from 1985 to 1991.

In terms of the balance between buyer and seller in the negotiation of contracts, the Report notes that most recently the contract balance would appear to be in favour of the buyer, a phenomenon best explained by the relative strength of the buyer in the previously existing over-supplied gas market. In contrast, contracts negotiated in the late 1970's and early 1980's, when there were perceived shortages of gas supply, may have tilted in the seller's favour. Naturally, the ebb and flow of this balance between buyers and sellers is the essence of a market-based contracting regime and the type of contract which may be

[90] (U.K.), 30 & 31 Vict., c. 3.

negotiated at any point in time under such a regime will largely be dictated by the market forces at play at that time.

The Report concludes that since the mid-1980's several fundamental changes have occurred to the long-term contracting regime governing the sale of Canadian natural gas. The impetus for this change has been the de-regulation of natural gas prices and markets in Canada and the U.S. along with the emergence of the Northeast U.S. as a major new market region for Canadian gas. The Report suggests that the changes that have occurred since the mid-1980's will set the pattern for future contracting practices in the industry. The most important changes are summarized as follows:

1. increased flexibility for both the buyer and the seller in long-term contracts;

2. greater balance between the buyer's obligations to purchase and the seller's obligation to deliver;

3. flexible and increasingly simple contract pricing terms that track competitive market conditions;

4. reduced contract volumes as smaller end-users and smaller producer/marketers enter the market and as larger buyers and sellers continue to diversify their supply portfolios and market outlets; and

5. unbundling gas sales and transportation service.

(ii) *Incentive Regulation Workshop*

The NEB's Incentive Regulation Workshop took place over a period of two and one-half days (January 19th - 21st, 1993) in Calgary. There was broad representation from Canadian pipeline companies as well as producers and pipeline shippers.

The workshop was not called to reach any specific conclusions but rather to facilitate discussion among interested parties with respect to the effectiveness of the Board's current Cost of Service ("COS") method of regulation and possible alternatives or supplementary methods thereto. The workshop, which reflected a diversity of views, did not lead to any specific conclusions but was primarily limited to broad, generic type statements. A report summarizing the discussions was issued in March 1993.

In general, the workshop reflected a continuing tension between producers, primarily the Canadian Association of Petroleum Producers ("CAPP") and the pipelines. The producers and CAPP were of the opinion that while COS regulation is not necessarily defective, it must be supplemented with some form of incentive regulation whereby the pipelines' returns are linked to their performance. The pipelines were reluctant to support any type of performance measurements emphasizing that they were each unique and suggesting that it would be very difficult to come up with meaningful, generic performance measurements that could provide a picture of pipeline performance on a comparative basis. Furthermore, the pipelines took the position that they are already well managed. CAPP countered that while Canadian pipelines may be run fairly competently, there is no basis upon which customers can satisfy themselves that this is so. CAPP argued that some sort of performance standards should be developed which would allow an "independent" evaluation of a pipeline's performance.

(iii) *Export Import Assessment Workshop*

The Export Impact Assessment ("EIA") forms one part of the public hearing component of the Board's Market Based Procedure. The MBP is used by the Board to assess long term gas export applications. The thrust of the EIA is to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices. The first EIA was released by the Board in 1989 followed by a draft update in September of 1992. The 1992 draft formed the basis for discussion during the Board's EIA workshop.

The EIA workshop took place on April 1, 1993 in Calgary. There was representation from the NEB, provincial regulatory bodies, pipelines, Eastern Canadian LDC's and Eastern Canadian industrial gas users. Conspicuous in its absence was the producer contingent although CAPP did forward a submission urging that the EIA be discontinued as its function is adequately carried out by the Board's general monitoring activities and the application of the Complaints Procedure.

There will be no immediate change resulting from the workshop. Any future change will not be implemented without the full consideration of interested parties. Interested parties or the NEB may use the ideas generated in the workshop for future proposals respecting the preparation of the EIA.

With respect to presenting a "control case", parties suggested doing away with this as people tend to focus on such a case as the norm or the standard of what is acceptable. On the supply side, the Board indicated that it will pay more attention to incorporating reserve additions due to technological improvements. Furthermore, the Board will pay more attention to non-conventional reserves, such as coalbed methane, tight gas and frontier reserves which will play a more important role in the future. All parties seem to be in general agreement that supply cost disaggregation by region and source is appropriate and helpful. With respect to the heavy fuel oil switching capability of the Eastern industrial market, the Board's present estimate that 75% of that market could switch may be high. The Canadian LDC's suggested 30% is more realistic.

The present wording of the EIA may be unrealistic in suggesting that it is possible to determine market adjustment difficulties. The NEB will continue to do what it can but cautioned that parties must be realistic about what the EIA is capable of offering.

(iv) *Early Public Notification*

In March of 1993, the NEB announced changes to the June 28, 1990 Memorandum of Guidance regarding early public notification procedures. The changed memorandum provides for public input during the planning and development stage of facilities projects.

(v) *Inquiry Concerning Transportation Safety Board Recommendations on Stress Commission Cracking*

The Transportation Safety Board of Canada ("TSB") is an independent federal government agency responsible for overseeing safety in various areas of transportation, including pipelines that are regulated by the NEB. As part of its responsibility, the TSB investigates and reports on accidents occurring on federally regulated pipelines. Over the past number of years several incidents have occurred on TransCanada PipeLines Limited ("TCPL" or "TransCanada") which appear to have resulted from Stress Corrosion Cracking ("SCC"). The information provided during the course of this proceeding indicates that this phenomena has been known to exist for many years (at least since 1965) and that a considerable body of evidence relating to the occurrence of this type of cracking in pipelines has been documented. Nonetheless, at this time, considerable uncertainty remains as to precisely why SCC takes place and how it can be detected and prevented.

The TSB made a series of recommendations to the Board which, if implemented, could have significant consequences for shippers on the TransCanada system, as well as for producers and purchasers of Canadian gas. These recommendations are summarized below:

1. the NEB ensure that the internal pressure in all federally regulated natural gas pipelines, where stress corrosion cracks have been found or are likely to exist, is below the threshold level for the origin or propagation of stress corrosion cracking;

2. the NEB, in collaboration with industry, develop improved methods for detecting and specific directions for repairing stress corrosion cracks; and

3. the NEB, in collaboration with provincial authorities and in consultation with industry, develop a set of operating restrictions to be applied industry-wide where stress corrosion cracking is suspected to exist in natural gas pipelines.

TCPL adopted a position that the recommendations of the TSB represent an inappropriate response to the existence of SCC on its pipeline system. Other parties' filing submissions also cautioned the Board against taking extreme action. Several submitters maintained that the recommendations of the TSB should be viewed as somewhat extreme, due to the fact that the state of knowledge is not as clear cut as portrayed by the TSB. Parties generally maintained that the approach adopted by TransCanada is a reasonable one as it combines protection of the public with the maintenance of pipeline integrity and service.

In the end, the Board found the evidence provided to demonstrate SCC is not a widespread problem and that the problem was being managed in a responsible fashion. The Board encouraged initiatives to research and detect SCC and undertook to monitor the results of any reviews, but did not impose any operating restrictions.

c. Evolving Matters

(i) *Revised NEB Rules of Practice and Procedure*

The Board is finalizing its revised Rules of Practice and Procedure and it is hoped that they will soon be formalized by being published in the Canada Gazette. The Board currently operates under the 1987 Draft Rules, as amended, which were never formalized.

Changes to the Draft Rules include specifying the Board's power to stay an application, changing subpoena requirements and limiting the target of information requests to only those parties who have filed evidence. It is also proposed that the review and rehearing procedures in Part V be simplified into a one-step procedure.

B. ALBERTA

1. Energy Resources Conservation Board

a. Decisions

(i) *Decision D 92-1*

This Decision relates to an application by Signalta Resources Limited ("Signalta") for a declaration by the ERCB that Amoco Canada Petroleum Company Ltd. ("Amoco") is a common carrier through certain of its pipelines of gas produced by Signalta from the Sugden Grand Rapids H Pool and an undefined Colony Pool.

In considering the matter, the ERCB restated the criteria to be established by a successful applicant seeking a common carrier order. These criteria are:

1. producible reserves are available for transportation through an existing pipeline;

2. there is a reasonable expectation of a market for the substance which is proposed to be transported by the common carrier operation;

3. the applicant could not make reasonable arrangements to use the existing pipeline; and

4. the proposed common carrier operation is either the only economically feasible way or clearly the most practical way to transport the substance in question, or is clearly superior environmentally.

On the basis of its analysis of these criteria, the ERCB granted Signalta's application.

Having decided that it would grant a common carrier order, the ERCB had to determine the specific terms of the order. The ERCB suggested that the common carrier provisions of the *Oil and Gas Conservation Act*[91] should not be used to guarantee the optimum return to an applicant. The ERCB also seemed to question whether either of Signalta or Amoco had been serious about pursuing give-and-take negotiations in respect of Signalta's utilization of the pipelines which are to be the subject of the common carrier order. Rather than imposing its order immediately, the ERCB deferred its decision for a period of two months during which time the parties were free to negotiate their own arrangement for the use of Amoco's facilities in place of that imposed by the ERCB.

There were certain other factual issues dealt with by the ERCB in this Decision which may be of some interest. First, there was the determination of the retroactive effective date of the common carrier order. As well, the ERCB discussed the question of whether the common carrier order should be limited to the Sugden Grand Rapids H Pool of the Signalta well (which was in communication with the producing Amoco well) or whether the order should also be extended to the other producing zone of the Signalta well, an undefined Colony zone. The ERCB concluded that because of the potential that a common carrier order had to override parties' private contractual arrangements, such orders should be strictly limited in their application. On this basis the Colony Pool of the Signalta well was not included in the common carrier order granted.

(ii) *Decision D 92-3*

This Decision provides for the granting of an application by Federated Pipelines Ltd. for the construction of a high vapour pressure products pipeline from Acheson to Fort Saskatchewan. Certain land owners intervened to oppose the construction of this pipeline on the basis of safety concerns and the potential diminution of their property values. The ERCB was satisfied that the pipeline would be safe. Further, as other pipelines were already carrying similar substances across the intervening landowners' properties, there would not likely be any serious diminution of value caused by the construction and operation of an additional products pipeline.

(iii) *Decision D 92-4*

This Decision relates to the consideration by the ERCB of an application by Koch Pipelines Limited ("Koch") to construct a 70 kilometer condensate pipeline in the Cochrane-Madden area. Intervenors who opposed this application at the ERCB hearing included ranchers, residential landowners and the Town of Cochrane. The application considered both the need for the condensate pipeline to replace very old existing facilities located in densely populated areas and the selection of an appropriate route for the pipeline.

It quickly became clear that the routing issue would become the focus of the hearing. Koch submitted its preferred routing as well as alternate routing for each of the four segments of the proposed condensate line. The intervenors cited a number of "not-in-my-backyard" reasons for opposing the construction of the pipeline along the particular

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91 *Supra* note 57.

segment of the route which, if utilized, would affect them. Ultimately, the ERCB was not convinced that Koch had fully evaluated the routing options that were available to it so as to minimize the impact of the pipeline on landowners and the environment alike.

As a result of the hearing, the ERCB deferred its decision on Koch's application until Koch submitted further evidence or an amended application in support of the proposed routing of the applied for pipeline. In deferring its decision, the ERCB also urged Koch to include the affected landowners in any evaluation process it might undertake in respect of its new routing proposals and urged such landowners to participate with Koch in this process.

(iv) *Decision D 93-1*

The ERCB approved the applications of NOVA for the construction of certain facilities needed to increase the gas delivery capacity of the NOVA system to the Alberta-British Columbia border. 830 mmcf/d of incremental capacity will feed the systems of ANG, Foothills, PGT and PG&E (the "PGT Expansion Project").

The Board addressed four issues:

1. the relationship between the subject applications and other regulatory procedures;

2. the need for the facilities including,

   the criteria for establishing need,
   gas supply and deliverability, and
   nature and reliability of the market;

3. the adverse effects on current NOVA shippers, landowners and the general public; and

4. the need for conditions relating to the size and timing of the facilities.

Some interveners noted that a number of gas removal permits for the PGT Expansion Project were held up and argued that it was inappropriate for the ERCB to approve the facilities in advance of the removal permits being issued. The ERCB found that the applications for the facilities were separate and distinct from the applications to remove gas from the province and should be considered on their own merits. As well, while Information Letter IL 90-8 did advise interested parties that concerns with NOVA's Annual Plan should be filed early, a public hearing is available where outstanding issues are unresolved through the consultative process.

With respect to the criteria necessary to establish the need for the facilities, the ERCB stated that private contractual arrangements supporting the facilities are not the exclusive indicator of need, however, the ERCB did concede that the contractual arrangements represented a strong belief that the facilities would be needed. Nor did commitment on downstream transportation facilities provide sufficient evidence of need. These commitments were business decisions undertaken by shippers who should be solely responsible for any associated risks. The ERCB also rejected the argument that facilities only be considered if they are to serve incremental markets.

In determining whether the expansion facilities were necessary, the ERCB looked at gas supply and deliverability and the nature and reliability of the market. With respect to the former, the ERCB concluded that there was more than sufficient reserves on a provincial basis to support the facilities. Further, recent deliverability shortfalls did not reflect inadequate provincial gas supply. With respect to the market, the ERCB considered the nature of both long-term and short-term markets and the regulatory uncertainties in California, however, it was ultimately concluded that the shippers were willing to accept the risks of the market.

The ERCB considered it unlikely that all volumes contracted to move in new facilities would be delivered under long-term contracts and took some comfort from the fact that long-term contracts accounted for about one-half of the applied-for capacity. The failure to support the capacity with long-term contracts for the other half was partly explainable by the regulatory uncertainties.

The ERCB rejected a proposal to approve only a portion of the facilities and approved the project in its entirety. The ERCB noted the commitment of all of the parties to the PGT Expansion Project to a common in-service date of November 1, 1993. Although they agreed that the timing of the in-service dates of all the facilities should be coordinated, it was not inclined to interfere with the freely negotiated terms of the agreements under which the facilities were being developed.

(v) *Decision D 93-2*

This Decision was a rejection of an application by Energy Consulting Inc. to build a gas-fired cogeneration plant in the Town of Stettler. The proposed development included a 25 megawatt power plant, a 30 acre greenhouse development to utilize both steam and electricity produced at the power plant and a transmission line to connect the power plant to Alberta Power's electrical distribution system. Based upon the submissions of the applicant and several intervenors, the ERCB concluded that there was no need for the additional electrical capacity that would be generated by the plant. It is worth noting that the 25 megawatt project does not fall within the Small Power Research and Development Program. This Program covers facilities which produce electrical energy from renewable sources such as solar, wind, municipal waste, hydro, geothermal, biomass or peat resources. While the ERCB recognized that the project would bring certain local benefits to the Town of Stettler, there was no particular reason for benefitting the town of Stettler as opposed to any other location in the province. As well, the ERCB concluded that most of the benefits to be derived from the project would come from the greenhouse preparation and not from the generation of excess electrical capacity.

A physical connection of the proposed facilities to the electrical distribution system of Alberta Power was not found to be a deterrent to the project. Rather, it was the price that the applicant requested as payment for the power which it contributed to the Alberta

Interconnected System. While the price for power included in the application may have made sense from the perspective of the economics of the proposed project, it was felt that these prices ignored the cost of power already available in Alberta and the current surplus of power on the Alberta Integrated System.

Strong interventions against this project by Alberta Power Limited, Transalta Utilities Corporation and to a lesser extent, by the electrical utility divisions of the municipal governments in Edmonton and Calgary, suggest that gas-fired cogeneration project applications in Alberta can expect a rocky ride for some time to come.

(vi) *Decision D 92-3*

This Decision relating to the applications of Amax Petroleum of Canada Inc. ("Amax") and Simon and Michael Skinner indicates that the ERCB will be giving considerable weight to landowners' concerns about environmental problems. The ERCB held that Amax has one year to move an oil battery, which the Skinners believe is impacting their health and quality of life, and four years to abandon nine wells which are in close proximity to the farming operation. The order was made despite the fact Amax had valid approvals for the battery and the nine wells. The Skinners made their application under s. 42 of the *Energy Resources Conservation Act*[92] ("*ERCA*") which gives the ERCB broad jurisdiction to reopen previous orders.

The facts of the dispute were unique but not complicated. The Skinners and their families live on a quarter section of land which contains four farm sites housing the Skinner families and their dairy facility. Amax's operations on the section of land owned by the Skinners include a battery site approximately 400 metres from the Skinner farm site, and nine wells close to the farm site. The Skinners requested that the ERCB review the permits and licenses related to the battery together with the wells which were drilled beside the farm site. The Skinners' application included concerns related to the impact of the battery and the intensive well development on their lands, their health and the health of their cattle with respect to noise, dust, air quality, adverse impacts on water quality, soil quality, and general negative psychological and physical impact.

In the 22 day hearing, the ERCB had to determine whether Amax would be allowed to proceed with further development involving the drilling of up to 55 new wells and, if drilling was to be allowed, what if any restrictions would be placed upon the drilling operations. The ERCB further had to decide whether the battery would have to be moved from its present location which the Skinners alleged was too close to their houses and their dairy and whether the current oil and gas production would have to be curtailed or eliminated due to the alleged negative impact upon the Skinners and their dairy operation.

It was ordered that further development was conditional on Amax moving the battery within one year. The battery must be moved to a site which will have less impact on the Skinners and their dairy operation. The ERCB also ordered that the nine wells closest to

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92 *Supra* note 19.

the Skinners' buildings must be abandoned and well site reclamation initiated within four years. The ERCB granted the Amax holding application respecting further development but did not grant well licenses and licenses for satellite production facilities, stating that these could be approved in the normal course once the battery was moved. It noted that detailed environmental planning should be submitted with the applications.

In its reasons for decision, the ERCB stated that intense oil development in close proximity to intense agricultural activities is unique. While the impacts on the environment from the oil operation were not shown to be hazardous to either the Skinners or their animals, the ERCB stated that the "potential" effects of operational difficulties have been exacerbated by their proximity to the Skinner family farm and by the type and size of the agricultural operation. The ERCB appeared to focus on the fact that while Amax dealt with a number of their operational difficulties, Amax had tended to be reactive, responding only to complaints or serious problems, rather than being proactive.

The ERCB was not convinced by the evidence that the battery represented a clear risk to the health of the Skinners or their dairy cattle. However, given the location of the battery, the ERCB accepted that whether the threat was real or not, the Skinners considered the battery to represent a totally unacceptable risk to their health, safety and livelihood. The ERCB accepted that the battery in its present location would interfere significantly with the Skinners' quality of life and their emotional well being and therefore may impinge on their ability to earn their livelihood from the dairy. Although Amax had met the minimum legislated separation distances, the ERCB stated that these minimum distances may not apply in certain situations, and certainly do not apply in respect of this section of land.

The message to take from the ERCB decision is that currently-held approvals may be in jeopardy if a landowner has environmental concerns about existing facilities. While the ERCB described the situation between Amax and the Skinners as "unique", the precedent-setting decision creates a "regulatory risk" which in itself can be costly. It is also noteworthy that the ERCB's decision was made despite the fact the ERCB found there was no scientific evidence to directly link Amax's operations to the negative effects being experienced by the Skinners' cattle. One of the bases of the ERCB's decision was the Skinners' *perception* that their health and safety were threatened by the Amax operation.

The following conclusions can be drawn from this decision:

1. It is paramount for oil and gas industry operators to consult, on an ongoing basis, with landowners to properly plan operations and to address potential problems before they occur. Implicit in the decision is to work out problems privately;

2. Existing valid approvals may be reopened by the ERCB at any time for landowner concerns (real or perceived) about environmental problems;

3. Operators are exposed to a "regulatory risk" if a particularly sensitive landowner wants to bring an application under s. 42 of the *ERCA*; and

4. The ERCB will require more detailed planning and assessment than it has in the past in regard to the environmental impacts and effects of operations before giving their approval. Again, implicit in the decision is a determination to maintain jurisdiction over all aspects of the energy industry in the face of some criticism by some environmental groups that it may be soft on environmental issues.

It its decision on costs dated April 23, 1993, the ERCB awarded the Skinners $406,104.83 in Local Intervener's costs which must be paid by Amax.

b. Reports

(i) *Review of the Operation of NOVA's Pipeline System: Issues and Recommendations*

In June of 1991, the then Alberta Minister of Energy requested the ERCB to carry out a review of the operation of the NOVA transmission system to identify and clarify existing problems and methods of addressing those problems. After receiving a number of submissions, the ERCB summarized its understanding of the issues and invited comments from NOVA and other participants. Based on those comments, the ERCB issued its report in July of 1992.

The ERCB reviewed fourteen specific issues relating to terms of service, expansion criteria and system design, rate issues and supply availability. NOVA and the other participants offered their views on each of these issues. These issues included:

1. appropriateness of initial contract terms;
2. adequacy of the 3-month notice period for one year renewable contracts;
3. contract relief for shippers stuck with excess capacity;
4. relationship between contracted and physical capacity;
5. optimization of system utilization by assignments and transfers;
6. economic criteria for new receipt capacity;
7. possibility of shortening the 27 month firm service cycle;
8. whether NOVA's costs reflect excessive design and standards;
9. availability of information regarding cost of service;
10. fairness and effectiveness of current rate design; and

11. roll-in of third party pipeline changes.

In its Report, the ERCB attempted to clarify the issues and concerns before initiating more formal proceedings or adopting measures to address the concerns. The ERCB did not commit to any recommendations, however, it did suggest that many of the issues could be resolved through the work of committees such as the Facilities Liaison Committee, the NOVA-Joint Industry Task Force and the Alberta Producers Group. With respect to other issues, such as contract demand relief, cost allocation, rate design and peak day supply, the ERCB believed that a joint hearing of the ERCB and the PUB may be useful.

The ERCB also reviewed issues surrounding the effectiveness of the current method of regulating NOVA's gas transmission operations. The ERCB's review in this regard is discussed below.

(ii) *Well License Transfer Criteria*

In November of 1992, the ERCB issued a paper on specific criteria which the ERCB will apply when a well license is being issued or transferred. That position was recently endorsed by CAPP, although the ERCB has been applying the criteria internally.

The new criteria attempts to address the ERCB's concern with the escalation in the number of "orphan wells." The criteria was developed by the ERCB to ensure that licensees are responsible and accountable, to limit the abandonment fund liabilities from future orphan wells and to encourage the timely abandonment of wells. The well license transfer criteria to be applied by the ERCB is in the industry's self interest considering that the abandonment fund is fully supported and maintained by the industry. The criteria is likely to limit potential draws from the fund. Highlights of the criteria are as follows:

1. All applicants are subject to an ERCB operational history surveillance review;

2. Establish a new first well license fee of $10,000.00;

3. Establish a well screening ratio for both the transferee and transferor for the initial processing of transfer applications to determine if a further review is necessary;

4. Establish well classification methods to evaluate each well in a transfer application that fails the well-screening ratio (item 3) and determine if a well deposit is required; and

5. Establish a well-deposit system for individual wells that do not meet the criteria, a deposit reduction for multiple well transfers and acceptable alternatives to the deposit and deposit refund criteria.

The criteria is to be applied on a trial basis for a minimum two-year period. Input from the industry as to the adequacy of the program will be sought as part of a two-year review.

b. Ongoing Matters

(i) *Syncrude Canada Ltd. Expansion Application*

Syncrude has applied to the ERCB for approval of the expansion of synthetic crude production at its plant near Ft. McMurray. The expansion is being contested by the Fort McKay First Nation and the Syncrude Environmental Assessment Coalition.

2. Public Utilities Board

a. Decisions

(i) *Decision C92028 — Re: Westcoast Energy Inc.*

Westcoast appealed an APMC decision resulting in a sulphur reserve credit to Husky Oil Operations Ltd.'s Alberta Cost of Service plus interest for a total amount exceeding $15 million, relating to production from the Savanna Creek gas field in southwestern Alberta. Westcoast had argued that a full sulphur revenue credit would result in a negative cost of service, which according to Westcoast was not permitted by the *Natural Gas Pricing Agreement Act*[93] or the *Natural Gas Price Administration Act.*[94] The PUB disagreed, finding no impediment to the possibility of a negative cost of service in certain circumstances.

The PUB awarded a credit to Husky and other Savanna Creek producers based on sulphur revenues (as opposed to the value of the sulphur) plus interest and in doing so found that:

1. Husky's claim was not limited by statements made by its counsel at a prior hearing into the matter;

2. Husky's claim for interest was not *res judicata*. In a prior hearing the Board had declined to exercise its jurisdiction which was not the same as making a conclusive determination; and

3. while the governing statutes do not conclusively set forth the matters which are to be determinative of the cost of service, interest on monies improperly withheld was an appropriate element to consider.

(ii) *Decision C92043 — Re: Hydra Resources Ltd.*

Hydra was the holder of both a gross overriding royalty ("GOR") and, pursuant to a farmout agreement, a working interest. North Canadian Oils ("NCO"), the farmee, was operator and partial owner of a processing plant which serviced the well in question.

[93] R.S.A. 1980, c. N.4.
[94] R.S.A. 1980, c. N.3.

Originally, NCO had included the capital cost of the gas plant in the farmout agreement payout account. However, when the gas plant cost was removed from the account, the well reached payout and Hydra converted its GOR to a working interest.

Hydra applied to the PUB for an order fixing just, fair and reasonable processing costs for gas produced from farmors' lands by the farmee (NCO). Both the farmout and royalty agreements were silent as to processing deductions.

Hydra took the position that the GOR was gross to all costs including processing. The Board disagreed and, insofar as was in its jurisdiction, held that the GOR was gross at the well head and subject to processing costs. The royalty agreement provided no method of calculating the processing fee, although with respect to the farmors' royalty, fees were calculated in accordance with the Department of Energy gas cost allowance ("GCA"). The PUB, based on an assumed capital structure and return on capital, found the GCA method of determining the processing fees to be fair and reasonable in the calculation of the GOR.

With respect to the farmout interest, the PUB found the question of whether or not a working interest had been earned to be beyond its jurisdiction. However, assuming Hydra was still in a royalty position, processing fees calculated in accordance with the GCA would be fair and reasonable. On the other hand, if Hydra was a working interest holder, it would only be responsible for its share of the cash operating expenses of the plant.

(iii) *Decision E92086 — Re: NOVA Tolls*

For the first time in a number of years, the PUB examined NOVA tolls. NOVA had fixed rates based on a common equity ratio of 35% and a rate of return of 13.5%. The Complainants (the Canadian Petroleum Association, the Independent Petroleum Association of Canada and the Alberta Gas Producers Group) had requested that the PUB set a common equity ratio of 25% with a rate of return on common equity of 12%. The PUB examined the capital structure of the Alberta Gas Transmission Division (the gas transmission arm) of NOVA, and set a common equity ratio of 32% and a rate of return on common equity of 12.5% for 1992.

b. Evolving Matters

(i) *Nova Tolls*

The Canadian Association of Petroleum Producers filed a complaint with the PUB claiming that the rates, tolls or charges fixed by NOVA as of January 1, 1993 were unjust and unreasonable. A pre-hearing conference was held and a hearing date of June 21, 1993 was set. The PUB has set the following issues to be addressed:

1. What is the appropriate capital structure for NOVA including the common equity ratio and an appropriate return on that ratio?

2. What is the appropriate cost factor of each component of the capital structure including the return on common equity?

3. Without restricting the generality of the foregoing, what is the effect of corporate diversification by NOVA outside the traditional utility area?

4. What is the appropriate method for recovery of costs of the elements of the capital structure inasmuch as such costs may vary from time to time or be effected by the corporate diversification of NOVA?

In addition, complaints were filed with respect to NOVA's plan to provide Contract Demand relief to shippers burdened by excess receipt point capacity. NOVA and shippers continued to work on a solution in an effort to avoid having the matter heard by a joint ERCB-PUB panel.

(ii) *Peace Pipe Line Ltd.*

Shippers on the Peace Pipe Line system have filed a complaint with the PUB with respect to the rates charged for transportation on that system. A hearing into the matter will likely be held in January 1994. If it is heard, it would be the first review by the PUB of an oil pipeline's tolls.

3. Miscellaneous

a. PUB-ERCB Integration

The ERCB, in its Review of the Operation of NOVA's Pipeline System noted a number of shortcomings of the existing regulatory system. These shortcomings have led some parties (*i.e.* the Electric Energy Marketing Agency) to recommend closer integration of the two boards, while others (*i.e.* CAPP) have called for a complete merger of the PUB and ERCB.[95] In its report, the ERCB noted that the split jurisdiction over regulating NOVA has led to some confusion and potential inefficiencies in operation and decision-making. Further, terms and conditions of service and rates and tolls are not necessarily distinct issues. The ERCB stated in its report that it believed that clarifying the existing jurisdiction of the two boards would make the status quo more workable, however, some changes to that jurisdiction would be desirable. The ERCB set out four regulatory alternatives:

1. modified status quo;

2. modified status quo with increased regulation;

3. modified status quo with complaints addressed to the Gas Utilities Board; and

4. a single board with combined jurisdiction.

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95 *Regulatory Times*, 7 April 1993.

The ERCB did indicate that it was prepared to work with government representatives and others as appropriate to choose and develop one of the alternate regulatory proposals. They recommended an informal process of obtaining input from interested parties rather than a hearing, because the final decision was the prerogative and responsibility of the government.

To that end, the government has taken steps to allow for the joint hearing of NOVA issues by the PUB and the ERCB. The *Energy Resources Conservation Amendment Act, 1992*[96] was assented to June 26, 1992 and had the effect of repealing the old s. 23 which allowed the ERCB to recommend to the Lieutenant Governor-in-Council the making of arrangements desirable for the co-operation with other governments or agents inside and outside of Alberta with respect to energy matters. In its stead, the new s. 23 allows the ERCB, without approval of the Lieutenant Governor-in-Council to participate in proceedings jointly or in conjunction with another Alberta tribunal.[97]

While the above amendment allowed the ERCB to sit with other tribunals, the PUB had no similar authority. Accordingly, in April of this year the government made the NOVA Joint Hearing Regulation,[98] pursuant to the *NOVA Corporation of Alberta Act*.[99] This regulation specifically allows the PUB and the ERCB to consult with each other and to conduct a joint hearing with respect to both rates and terms and conditions of service.

b. Natural Resources Conservation Board

(i) *Application 9103 — Three Sisters Golf Resorts Inc.*

While energy projects are not subject to review by the Natural Resources Conservation Board ("NRCB"), the decisions of the NRCB are likely to be given considerable weight in regard to environmental issues, particularly in light of public concern with equivalency between the NRCB and the ERCB. In assessing a project, the NRCB must determine if the project is in the public interest, having regard to the social and economic effects of the projects and the effect of the project on the environment. That test must also be met by energy projects coming before the ERCB.

In the Three Sisters hearing, the NRCB held that in order to determine whether a project is in the public interest, the NRCB must have regard to each of the social effects, economic effects and environmental effects of the proposed project. The NRCB must then weigh all of the effects and determine, after balancing the overall effects, if the project is in the public interest. The NRCB expressly rejected the argument that the project must be in the public's interest for each component of the test.

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96 S.A. 1992, c. 14.

97 Lieutenant Governor-in-Council approval is, however, required for agreements and joint proceedings with the Government of Canada or any federal tribunals or agencies.

98 O.C. 257/93.

99 *Supra* note 56.

c. Intra-Alberta Core Market Policy Discussion Paper

On March 17, 1993, the Alberta government released its Discussion Paper relating to core market access to the direct sales natural gas market. The *Gas Utility Statutes Amendment Act, 1990*[100] had previously provided Alberta consumers the right to enter into direct sales arrangements for natural gas supply, but the Act does not come into force until proclamation and proclamation of the sections pertaining to the core market awaits completion of the regulations.

In the Discussion Paper, the government of Alberta proposes the following:

1. the core market will consist of all residential and commercial (including institutional) gas consumers but not central steam plants and cogeneration facilities involving commercial or industrial hosts where the facilities have sustainable alternate fuel capability;

2. all consumers will be eligible to remain as sales customers of the distribution companies or to enter into direct sales arrangements;

3. core consumers will be divided into two categories, the first being small commercial consumers (less than 5,000 gigajoules annually) and residential dwelling units, and the second being large commercial and institutional consumers;

4. core consumers will have to meet minimum contract standards including minimum terms, deliverability assurances, firm transportation and backstopping arrangements; and

5. core consumers leaving or returning to the utility system will be subject to the costs of doing so.

The government had anticipated cabinet approval of the regulation by this time and regulatory resolution of the details concerning costs and rates by the end of the year. Initial core direct sales for larger consumers would be possible by November 1994, and the following year for smaller consumers.

d. Protected Areas Policy "Special Places 2000"

The government of Alberta is currently embarking on a province-wide consultation regarding protection of wilderness areas. The project is called "Special Places 2000": Alberta's Natural Heritage." The goal of the project is to complete a comprehensive system of protected areas in the Province of Alberta on the following bases:

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100 S.A. 1990, c. 21.

1. To protect the full range of landscapes, environmental diversity and special natural features of Alberta;

2. To protect natural landscapes throughout Alberta for a variety of resource based, recreation pursuits;

3. To protect landscapes and ensure, for Albertans and visitors, the opportunity to explore, understand and appreciate the full range of Alberta's natural heritage; and

4. To protect areas capable of sustaining adventure travel and tourism including extended tours, and to enable visitors to experience the unspoiled landscapes and abundant wildlife represented by Alberta's natural regions.

The designation of certain areas as protected natural areas is likely to have an impact on oil and gas development in those areas.

e. Reorganization of the Ministry of Environment and Ministry of Land, Forests and Wildlife

The Ministries of Environment and Lands, Forests and Wildlife were reorganized as of March 26, 1993 to create the Department of Environmental Protection. The Department is organized into seven major service areas, being:

1. Environmental Regulatory Services;

2. Fish and Wildlife services;

3. Land and Forest services;

4. Parks services;

5. Water Resources services;

6. Research and Planning services; and

7. Finance and Program services.

In the vision document issued by the Department of Environmental Protection, certain principles are committed to. Of note is the principle that the Department of Environmental Protection will promote public involvement in all decisions affecting the environment, and environmental protection and enforcement will be firmly and fairly enforced within the regulatory framework. As has been the case in other jurisdictions (for example, Ontario), the Department of Environmental Protection is likely to become an increasingly important department with increasing influence over other departments. Whether that will translate into the type of regulatory enforcement in Ontario, which has seen exponential growth in prosecutions for environmental offences, remains to be seen.

f. APMC — Decision 921214-01 Take or Pay Costs Sharing Amendment

In December of 1992, the Alberta Petroleum Marketing Commission announced that certain levies payable under the *Take-or-Pay Costs Sharing Act* would be discontinued at the end of 1992. The levy, which assisted TCPL and Consolidated Natural Gas producers with take-or-pay carrying costs, was initially set in November 1, 1986 and had gradually been reduced over the years.

C. BRITISH COLUMBIA

2. British Columbia Utilities Commission

a. Decision — A Generic Hearing for the Review of Domestic Natural Gas Supply rules

In June of 1992, the Ministry of Energy, Mines and Petroleum Resources advised that it was reviewing the British Columbia Core Market Policy. In November, the Ministry released its new policy statement on domestic natural gas supply — "Domestic Supply Policy" ("DSP"). The DSP was to be implemented by the British Columbia Utilities Commission ("BCUC") and accordingly the BCUC undertook to review its core market rules. A decision was rendered March 11, 1993.

While the rules set by the BCUC apply to all gas consumers, they treat core market consumers, for whom security of supply is most important, differently from those consumers who have standby alternative fuel capability. With respect to security of supply, the BCUC found that gas supply contracts for the core market no longer needed to be backed by ten to fifteen years of reserves and deliverability. Instead, the BCUC set a four-year rolling average as the minimum reserve and deliverability requirement of all contracts for core market consumers. The BCUC also loosened backstopping and corporate warranty requirements.

As well, the BCUC implemented a requirement that agents, brokers and marketers of natural gas obtain a licence prior to engaging in direct sales to core market consumers. These marketers, in consultation with local distribution companies, are to produce a code of conduct that will be approved by the BCUC. With respect to transportation on the Westcoast system, it was concluded that suppliers of direct sales gas should first seek assignment of capacity from the Local Distribution Company ("LDC"). If LDC-held transportation capacity is unavailable, the direct sale gas supplier may provide its own Westcoast capacity.

By December 31, 1993, each LDC is required to file a proposed plan for the BCUC's consideration. The BCUC intends to review a number of further issues prior to May 1, 1994.