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

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The purpose of this paper is to provide a brief review of recent legislative and regulatory developments of particular interest to oil and gas lawyers. In addition to reporting on recent changes in statutes and regulations, and recent decisions and published policy statements of administrative bodies, the paper also discusses a number of legislative and regulatory developments which are still evolving. In order to place some limit on the scope of the paper, only federal and Alberta legislative and regulatory developments are reported. The exception to this limitation is a report on recent Ontario Energy Board decisions relating to the marketing of natural gas.

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I. LEGISLATIVE CHANGES

A. FEDERAL LEGISLATION

1. Statutes

(a) Revised Statutes of Canada, 1985

As reported in last years paper,[1] the First Supplement and the Second Supplement were declared in force on December 12, 1988.[2] The Third Supplement was declared in force on May 1, 1989[3] and the Fourth Supplement was delcared in force on November 1, 1989.[4] The *Revised Statutes of Canada, 1985* consolidates substantially all federal statutes passed from 1970 to December 31, 1984, the cut-off date for the 1985 revision. All federal statutes passed or proclaimed in force after December 31, 1984 and before the proclamation of the *Revised Statutes of Canada, 1985* have now found their way into one of the four supplements. There are publications available which are designed to facilitate the transition from the 1970 to the 1985 revision.

(b) Canadian Exploration and Development Incentive Program Act, measure to amend, S.C. 1989, c.19

As reported in last years paper, one of the stated aims of the Canadian Exploration and Development Incentive Program was to help mining and oil and gas exploration companies that have traditionally relied upon flow-through shares to raise funds from equity markets. The *Canadian Exploration and Development Incentive Program Act*[5] applied to expenses incurred in oil and gas exploration after March 31, 1987. The operative portion of the *Canadian Exploration and Development Incentive Program Act*, measure to amend, is that notwithstanding any other provision of the *Canadian Exploration and Development Incentive Program Act*, the same does not apply in respect of any eligible expenses incurred on or after January 1, 1990.

(c) Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act, S.C. 1988, c. 28

On August 26, 1986 the Federal Government and the Government of the Province of Nova Scotia entered into the "Canada-Nova Scotia Offshore Petroleum Resources Accord" dealing with offshore petroleum resource management and revenue shar-

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1. Donald C. Edie and E. Mitchell Shier, "Recent Developments of Interest to Oil and Gas Lawyers" (1990) 28 Alta. L. Rev. 296.
2. SI/88-228 and 239.
3. SI/89-123.
4. SI/89-231.

4a. *The Revised Statutes of Canada, 1985 - Concordance*, (Don Mills: Richard De Boo Publishers, 1988).

5. S.C. 1987, c. 18.

ing. This Act, which was proclaimed in force on December 22, 1989[6] [except for Div. VIII (i.e., Transfers, Assignments and Registration) of Part II (i.e., Petroleum Resources)] implements this accord.

(d) Canadian Environmental Protection Act, measure to amend, S.C. 1989, c. 9

This Act was proclaimed in force on June 29, 1989. Section 36(1) of the *Canadian Environmental Protection Act*[7] ("CEPA"), provides that "where there occurs or is a reasonable likelihood of a release into the environment of a substance specified on the list of Toxic Substances in Schedule I in contravention of a regulation made under section 34 or an order made under section 35" any person described in section 36(2) has the duty to report the release or possible release of toxic substances to an inspector and to take emergency measures to either prevent the release or to remedy any dangerous situation caused. The list of toxic substances in Schedule I to CEPA presently consists of only nine substances. The operative portion of CEPA, measure to amend, is to permit the Governor in Council, if satisfied that a substance is toxic, to make an order adding the substance to the list of toxic substances in Schedule I to CEPA. The Minister is currently in the process of reviewing submissions with respect to an expansion of the list of toxic substances.

(e) Canada-United States Free Trade Agreement Implementation Act, S.C. 1988, c. 65

As reported in last years paper, this Act received royal assent on December 30, 1988 and was proclaimed in force on January 1, 1989. Section 135 of this Act has the effect of amending the *Investment Canada Act*[8] which applies to transactions that result in the acquisition of control of a Canadian business by a non-Canadian. The *Investment Canada Act* requires either simple notification or an approval, depending on the size of the transaction. The threshold amounts are subject to change as a result of the *Canada-United States Free Trade Agreement Implementation Act* which will see, subject to certain exceptions noted below, an increase in the direct acquisition threshold over a five year phase-in period so that after 1992, the threshold will be $150 million. Any transaction involving the acquisition of control of a Canadian business which is above the size threshold requires the prior approval of Investment Canada. In order to be approved, the investment must be judged to be of benefit to Canada.

Notwithstanding the foregoing, it is important for oil and gas practitioners to note that with respect to the revised threshold amounts provided for in section 14 of the *Investment Canada Act,* section 14.1(8) of the Act provides:

14.1(8) This section does not apply in respect of an investment to acquire control of a Canadian business that

(a) engages in the development of oil or natural gas and owns an interest in proven reserves of oil or natural gas in Canada;

(b) engages in the production of uranium and owns an interest in a producing uranium property in Canada;

6. SI/90-9.

7. S.C. 1988, c.22.

8. S.C. 1985, c. 20.

(c) provides any financial service;
(d) provides any transportation service; or
(e) is a cultural business.

(f) Federal Budget of February 20, 1990

The Federal budget announced the early termination of the Canadian Exploration Incentive Program ("CEIP") effective February 20, 1990 subject to grandfathering rules for expenses committed under flow-through share financing arrangements entered into before February 20, 1990. Expenses incurred after February 19, 1990 will cease to be eligible for CEIP, other than expenses incurred prior to March 1, 1991 pursuant to a "Grandfathered Agreement". A "Grandfathered Agreement" is an agreement in writing entered into before February 20, 1990 which is either a flow-through share agreement between an exploration company and a flow-through share investor or a subscription agreement entered into between an investor and a fund pursuant to a final prospectus which has been filed with a securities commission in Canada. Notwithstanding the cancellation of CEIP, junior oil and gas companies can still use flow-through shares to finance exploration using the beneficial provisions of the *Income Tax Act*[9a] pertaining to flow-through shares, which have been retained. The budget announcement with respect to CEIP will be implemented by amendments to the *Canadian Exploration Incentive Program Act.*[9b]

The Federal budget also announced that the Federal Government would continue to participate in the OSLO consortium only until the end of the engineering and conceptual phase which must be completed by July 1, 1991 when the consortium will decide whether to proceed with construction of the project. In an address to the Petroleum Joint Venture Association, Federal Energy Minister Jake Epp defended Ottawa's commitment to pull out of the OSLO megaproject stating that the government cannot ask taxpayers to "support OSLO to the tune of $650 million" given the "marginal economics" of the project.

2. Regulations

(a) Investment Canada Regulations, amendment SOR/89-69

As noted previously under the heading the *Canada-United States Free Trade Agreement Implementation Act*, non-Canadians who wish to acquire a Canadian business must file either a notification or an application for review with Investment Canada. These amendments to the *Investment Canada Regulations*[10] require non-Canadians to provide additional information in these notification and application forms. In particular, non-Canadians must indicate whether or not they are Americans and whether or not the Canadian business that is being acquired is controlled by an American. If a notification form is being completed, the non-Canadian may also have to provide further information on the business activities of the target company. Finally, these

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9a. S.C. 1988, c. 34.
9b. S.C. 1970-71-72, c. 63 as amended.
10. SOR/85-611.

amendments confirm that the existing methods for calculating the value of assets apply to the new higher thresholds for review that are part of the amendments discussed above.

(b) Canadian Exploration and Development Incentive Payment Variation Order (July 1989), SOR/89-320

As reported in last years paper, on September 30, 1988 the Federal Government announced a revised phase-down of the CEDIP incentive rate. As of October 1, 1988, the incentive rate was reduced from 33% to 25%, rather than to 16.66%. This 25% rate was to stay in effect until June 30, 1989 and then drop to 16.66% for the period from July 1, 1989 to December 31, 1989. The purpose of this Order in Council was to implement the scheduled phase-down of the CEDIP incentive rate from 25% to 16.66% effective as of July 1, 1989.

(c) Oil and Gas Spills and Debris Liability Regulations, amendment, SOR/89-369

The *Oil and Gas Production and Conservation Act*[11] imposes on an operator absolute liability up to an "applicable limit" for damages resulting from an oil spill or debris in the area in which operations are being conducted. The "applicable limits" are prescribed by regulation. In the area where the *Arctic Waters Pollution Prevention Act*[12] applies, the potential existed for an overlapping of liability with the application of both the *Oil and Gas Production and Conservation Act* and the *Arctic Waters Pollution Prevention Act.* In order to avoid this overlapping of liability and to permit the *Arctic Waters Pollution Prevention Act* to take precedence, the limit of absolute liability under the *Oil and Gas Production and Conservation Act* was set as the amount by which $40 million exceeded that prescribed under the *Arctic Waters Pollution Prevention Act.* However, the French version of the regulation employed language that in effect re-established two levels of liability should the limit prescribed under the *Arctic Waters Pollution Prevention Act* be changed. This amendment to the *Oil and Gas Spills and Debris Liability Regulations* was effected simply to ensure consistency between the English and French versions of the regulations by remedying the ambiguity created in the French version.

(d) Public Lands Mineral Regulations, amendment, SOR/89-448

The amended *Public Lands Mineral Regulations* allow the Minister of Energy, Mines and Resources to enter into a mineral lease without calling for tenders when the lessee is the registered owner of the surface rights of the lands under which the minerals are situated. Previously, the *Public Lands Mineral Regulations*[13] provided for the issuance of mineral leases by way of public tender with the grantee being the person submitting the highest offer. It was thought that this method of disposition had proved not to be expedient for surface mining of minerals. As this type of mining operation requires the use and disturbance of the surface rights, the Crown has

11. R.S.C. 1985, c. O-7.
12. R.S.C. 1985, c. A-12.
13. C.R.C. 1978, c. 1325.

followed the practice of only considering applications for lease from a surface owner. Therefore, the public tender process, as required by the regulations, was considered in these instances to be inappropriate and time consuming.

(e) Canadian Exploration and Development Incentive Program Regulations, amendments, SOR/89-640

This amendment to the CEDIP Regulations is independent of the immediate termination of the CEDIP program discussed below and includes both substantive and housekeeping amendments. Substantive amendments (i.e., section 24 has been amended to reflect revised filing deadlines) have been undertaken to ensure the orderly administration of CEDIP. The amendments of a housekeeping nature have been implemented so as to clarify the existing provisions.

As mentioned above, on April 26, 1989 is was announced in the Federal budget that CEDIP (established on March 25, 1987 as a "transitional measure to provide cash incentives to the oil and gas industry to help it overcome the impact of the decline in world oil prices on employment and investment") would be immediately terminated, except for grandfathered expenses.

(f) Energy Monitoring Regulations, amendment, SOR/89-531

These amendments to the *Energy Monitoring Regulations*[14] promulgated the Monitoring Survey Questionnaire for the first half of the year 1988, revoking Schedules I to IX of the *Energy Monitoring Regulations.*

(g) Petroleum and Gas Revenue Tax Regulations, amendment SOR/89-553

The Petroleum and Gas Revenue Tax ("PGRT") on oil and gas production was originally announced as part of the National Energy Program of October, 1980 and came into effect in 1981. On March 28, 1985 it was announced as a part of the Western Accord that there would be a PGRT exemption with respect to revenue from new production and that the PGRT would be phased-out by the end of 1988. On September 9, 1986 it was announced that the PGRT would be entirely eliminated with respect to revenues attributable to production after September 30, 1986. These regulations were required to implement the measures announced in the Western Accord and to terminate PGRT in the manner announced by the Federal Government.

3. Proposed Changes

(a) Bill C-23, An Act to Amend the National Energy Board Act and to Repeal Certain Enactments in Consequence Thereof, 2d Sess., 34th Parl., 1989.

This Bill was introduced by Jake Epp, Minister of Energy, Mines and Resources and has received first, second and third readings in the House of Commons (June 7, 1989, October 6, 1989 and December 14, 1989). The Bill has also received first and second reading in the Senate (December 14, 1989 and December 20, 1989). The Bill

14. SOR/83-172.

will provide that the period for obtaining leave to appeal from a decision of the National Energy Board ("NEB") to the Federal Court of Appeal will run from the date of the release of a decision or order. The Bill will also add a new part (i.e., Part III.1) to the *National Energy Board Act*[15] respecting construction and operation of powerlines. Finally, this Bill will add new provisions respecting the exportation of electricity.

Statutes which will be affected by this Bill are the *National Energy Board Act*[16] and *An Act to Amend the National Energy Board Act.*[17]

(b) Bill C-44, Hibernia Development Project Act, 2d Sess., 34th Parl., 1989.

This Bill was introduced by Doug Lewis for Jake Epp, Minister of Energy, Mines and Resources and has received first reading in the House of Commons (November 7, 1989). This Bill provides authority for the Minister of Energy, Mines and Resources to enter into agreements on behalf of the Government of Canada respecting the Hibernia Development Project. This Bill sets out the application of federal and provincial laws and the jurisdiction of the Courts respecting the offshore area.

Statutes which will be affected by this Bill are the *Canadian-Newfoundland Atlantic Accord Implementation Act,*[18] the *Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act*[19] and the *Canada Petroleum Resources Act.*[20]

(c) Bill C-45, OSLO Oil Sands Project Act, 2d Sess., 34th Parl., 1989

Like Bill C-44 this Bill was also introduced by Doug Lewis for Jake Epp, Minister of Energy, Mines and Resources and has received first reading in the House of Commons (November 7, 1989). This Bill provides authority for the Minister of Energy, Mines and Resources to enter into agreements on behalf of the Government of Canada respecting the OSLO Oil Sands Project.[21] There are no existing Acts affected by this Bill.

(d) Bill C-39, Canadian Laws Offshore Application Act, 2d Sess., 34th Parl., 1989

This Bill was introduced by Doug Lewis, Minister of Justice and Attorney General of Canada and has received first reading in the House of Commons (October 2, 1989). The proposed legislation will provide a legal framework for extending Canadian laws and Court jurisdiction to continental shelf areas beyond the twelve mile territorial limit. With this Bill, Federal laws will be extended to oil rigs and other marine installations. Provincial and territorial laws will also be extended to adjacent offshore areas on an individual basis, following consultations and negotiations with the province or territory involved. The proposed legislation will also broaden the application of Canadian criminal law and jurisdiction in respect of offenses on the continental shelf and other offshore areas.

15. R.S.C. 1985, c. N-7.
16. R.S.C. 1970, c. N-6.
17. R.S.C. 1970 (1st Supp.), c. 27.
18. S.C. 1987, c. 3.
19. S.C. 1988, c. 28.
20. R.S.C. 1985 (2nd Supp.), c. 36.
21. See page 4.

Statutes which will be affected by this Bill are the *Canada Labour Code*,[22] the *Canada Shipping Act*,[23] the *Coastal Fisheries Protection Act*,[24] the *Criminal Code*,[25] the *Immigration Act*[26] and the *Territorial Sea and Fishing Zones Act*.[27]

(e) Bill C-4, An Act to Amend the Energy Supplies Emergency Act and to Amend the Access to Information Act in Consequence Thereof, 2d Sess., 34th Parl., 1989.

This Bill, which was reported in last years paper and which in part changes the requirements respecting Canada's representation within the International Energy Agency, has now received first, second and third readings in the House of Commons (April 12, 1989, June 20, 1989 and December 11, 1989). This Bill has also received first and second readings in the Senate (December 12, 1989 and December 20, 1989).

Statutes which will be affected by this Bill are the *Access to Information Act*[28] and the *Energy Supplies Emergency Act*.[29]

(f) Bill C-62, Excise Tax Act and Related Acts, measure to amend, 2nd Sess., 34th Parl., 1989

Bill C-62 which contains amendments to the *Excise Tax Act*,[30] the *Criminal Code*, the *Income Tax Act*, the *Statistics Act*,[31] the *Excise Act*,[32] the *Customs Act*,[33] the *Customs Tariff Act*[34] and the *Tax Court of Canada Act*[35] received third reading in the House of Commons on April 10, 1990. The Bill replaces the existing Federal sales tax with a tax on the consumption of goods and services (the "GST") in Canada. It is proposed that the GST will be implemented at the rate of 7% effective January 1, 1991.

The GST is a tax on final consumption. Unlike provincial retail sales tax, the 7% GST will be applied at every stage of the production and distribution chain. A business will charge GST on the full price of its taxable goods and services and claim an input tax credit for the GST which is paid on purchase of inventory, services and fixed assets which have been used in a commercial activity.

The 7% GST will be exigible on all sales of oil and gas throughout the production and delivery system. Vendors in the oil and gas business will be entitled to claim an

22. R.S.C. 1985, c. L-2.
23. R.S.C. 1985, c. S-9.
24. R.S.C. 1985, c. C-33.
25. R.S.C. 1985, c. C-46.
26. R.S.C. 1985, c. I-2.
27. R.S.C. 1985, c. T-8.
28. R.S.C. 1985, c. A-1.
29. R.S.C. 1985, c. E-9.
30. R.S.C. 1985, c. E-15.
31. R.S.C. 1985, c. S-19.
32. R.S.C. 1985, c. E-14.
33. S.C. 1986, c. 1.
34. R.S.C. 1985, c. C-54.
35. R.S.C. 1985, c. T-2.

input tax credit for all GST which they incur on all of their purchases related to such activities. However, there will be no GST exigible on the sale of working interests, royalty interests and similar oil and gas rights. An election is available with respect to joint ventures in order to reduce the administrative burden of GST on non-operators.

It is possible for an oil and gas company to be treated as a financial institution for GST purposes if production revenues are low and there is significant passive income such as interest income. The rules relating to the calculation of input tax credits are more onerous for financial institutions.

(g) Canadian Environmental Assessment Act

The Federal Government announced in the 1989 Speech from the Throne that it would be introducing legislation to establish a more effective environmental assessment and review process. Legislation to be known as the *Canadian Environmental Assessment Act* will likely be tabled later this year. Further, Environment Canada has circulated its "Green Paper" to the public and industry as part of the consultative process being undertaken as a first step towards preparation of new Federal environmental policy and legislation.

B. ALBERTA LEGISLATION

1. Statutes

(a) Alberta Energy Company Amendment Act, 1989, S.A. 1989, c. 1

This legislation removes restrictions originally contained in the *Alberta Energy Company Act*[36] that permitted only Canadian citizens to hold shares in Alberta Energy Company Ltd. ("AEC") although shares in the hand of non-residents, pursuant to this new legislation are restricted to no greater than 10% of the voting shares in any class. This legislation also provides for a mechanism by which a person who holds shares in contravention of the charter of AEC can be required to dispose of his or her shares. Finally, this legislation prevents AEC from continuing in another jurisdiction and/or from alienating the majority of its assets.

(b) Miscellaneous Statutes Amendment Act, 1989, S.A. 1989, c. 17

Section 12 of this Act amends section 33(2)(a) of the *Land Surface Conservation and Reclamation Act*[37] by striking out "55" and substituting "54". The Act now has provision for the return of a deposit given pursuant to the Regulations if a reclamation certificate has been issued by the Land Conservation and Reclamation Council.

(c) The Personal Property Security Act, S.A. 1988, c. P-4.05

The writers note that this Act will be the subject of a separate paper and accordingly only make reference here to the fact that the Act was passed on July 6, 1988 and, with the exception of the provisions relating to the *Partnership Act*,[38] comes into force on October 1, 1990.

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36. R.S.A. 1980, c. A-19.
37. R.S.A. 1980, c. L-3.
38. R.S.A. 1980, c. P-2.

2. Regulations

(a) Oil and Gas Conservation Regulation Amendments, Alta. Reg. 153/89, 19/90

Alberta Regulation 153/89 decreases the annual adjustment factor from 0.86 to 0.84 for the Energy Resources Conservation Board's ("ERCB") fiscal year 1989/90. This adjustment factor is applied to the administration fees applicable to individual wells and oil sands projects as prescribed in sections 16.070 and 16.080 of the *Oil and Gas Conservation Regulations.*[39]

Alberta Regulation 19/90 effects numerous changes to the Regulations insofar as they pertain to drilling, completing, production and servicing operations and the prevention of losses, injuries, damages and fires.

(b) Gas Utilities Act Designation Regulation Amendments, Alta. Reg. 45/89, 280/89

The *Gas Utilities Act Designation Regulation*[40] designates those owners of gas utilities to which sections 25.1 and 26 of the *Gas Utilities Act*[41] apply. Alberta Regulations 45/89 and 280/89 delete Border Utilities Ltd., ATCO Utilities Holdings Ltd. and 474243 Ontario Ltd. from the list of such gas utility owners.

(c) Natural Gas Royalty Regulation Amendments, Alta. Reg. 276/89, 277/89

Alberta Regulation 276/89 effects a number of definitional changes to the *Natural Gas Royalty Regulations*[42] as well as expanding the provisions of the original Regulations insofar as they pertain to "royalty client" payment and reporting requirements.

Alberta Regulation 277/89 simply stipulates that the Crown will not be liable for the costs and allowances that are incurred in the gathering, compressing or processing of the Crown's royalty share of natural gas if credits have been established under the *Sulphur Emission Control Assistance Regulation.*[43]

(d) Alberta Average Market Price Regulation (No. 1) Amendments, Alta. Reg. 140/89, 163/89, 191/89, 212/89, 235/89, 262/89, 293/89

These amendments set the Alberta average market price for natural gas and residue gas for the production months of June through December, 1989 for the purposes of the *Natural Gas Royalty Regulations.*

39. Alta. Reg. 151/71.
40. Alta. Reg. 171/85.
41. R.S.A. 1980, c. G-4.
42. Alta. Reg. 16/74.
43. Alta. Reg. 275/89.

(e) Crude Oil Price and Royalty Factor (No. 4) Amendments, Alta. Reg. 111/89, 164/89, 190/89, 211/89, 234/89, 261/89, 294/89

These amendments set the old oil par price, the new oil par price, the old oil royalty factor and the new oil royalty factor for the production months of May through December, 1989 for the purposes of the *Petroleum Royalty Regulations.*[44]

(f) Permit Conditions Regulation Amendment, Alta. Reg. 274/89

Every permit granted pursuant to section 6(1) of the *Gas Resources Preservation Act*[45] to remove gas from the Province of Alberta is subject to a number of conditions. This amendment removes two of these conditions, specifically the "self-displacement" condition (i.e., gas shall not be removed from Alberta if the distributor takes delivery, on a daily basis, of less than the maximum quantity of gas that the distributor is entitled to take delivery of or any lesser quantity consented to in writing by the Minister of Energy) and the "surplus test" condition (i.e., gas shall not be removed from Alberta unless before the removal occurs, the Minister of Energy has given written notice to the ERCB that the Minister is satisfied that the review of the surplus test being conducted by the NEB at the time has resulted or will result in significantly freer access to export markets for gas produced in Alberta).

(g) Gas Resources Preservation Regulation, Alta. Reg. 273/89

This regulation which repeals the *Removal of Propane Exclusion Regulation*[46] stipulates in part that any propane that is intended to be removed from Alberta by pipeline or by any other means is excluded from the application of the *Gas Resources Preservation Act.*[47]

(h) Energy Grant Regulation Amendment, Alta. Reg. 328/89

Pursuant to section 7 of the *Department of Energy Act,*[48] the Minister of Energy may make grants if he is authorized to do so by the *Energy Grant Regulations.*[49] This amendment to the Regulations permits the Minister to make grants to any of Canadian Occidental Petroleum Ltd., Esso Resources Canada Limited, Gulf Canada Resources Limited, PanCanadian Petroleum Limited, Petro-Canada Inc. and the Province of Alberta in respect of the OSLO Oil Sands Project.

(i) Take-or-Pay Costs Sharing Act General Levy Order, Alta. Reg. 239/89

This order prescribes the rate of the levy (7 cents per gigajoule) payable by a customer of NOVA, an Alberta Corporation ("NOVA"), a provincial system customer or a provincial carrier liable for the payment of a levy by reason of section

44. Alta. Reg. 93/74.
45. R.S.A. 1980, c. G-3.1.
46. Alta. Reg. 447/78.
47. *Supra*, note 45.
48. R.S.A. 1980, c. D-18.1.
49. Alta. Reg. 309/86.

2(4)(d) of the *Take-or-Pay Costs Sharing Act*[50] for the twelve month period commencing November, 1989 and ending on October, 1990.

(j) Take-or-Pay Costs Sharing Act Consolidated Levy Orders, Alta. Reg. 154/89, 188/89, 200/89, 229/89, 252/89, 284/89, 339/89, 16/90, 40/90, 77/90

Pursuant to section 2(5)(b) of the *Take-or-Pay Costs Sharing Act,* these orders prescribe the rates of the levies payable on gas upon its delivery to Consolidated Natural Gas Limited during the months May, 1989 through February, 1990.

(k) Take-or-Pay Costs Sharing Act TCPL Levy Orders, Alta. Reg. 155/89, 187/89, 201/89, 230/89, 253/89, 285/89, 340/89, 15/90, 39/90, 78/90

Pursuant to section 2(5)(b) of the *Take-or-Pay Costs Sharing Act,* these orders prescribe the rates of the levies payable on gas upon its delivery to TransCanada PipeLines Limited during the months May, 1989 through February, 1990.

(l) Public Utilities Board Act Designation Regulation Amendments, Alta. Reg. 46/89, 281/89

The *Public Utilities Board Act Designation Regulation*[51] designates those owners of public utilities to which sections 91.1 and 92 of the *Public Utilities Board Act*[52] applies. Alberta Regulations 46/89 and 281/89 delete ATCO Utilities Holdings Ltd. and 474243 Ontario Ltd. from, and add AEC Power Ltd. and Acheson Park Water Corporation to, the list of such public utility owners.

(m) Natural Gas Marketing Regulation Amendments, Alta. Reg. 278/89, 313/89

Alberta Regulation 278/89 reduces the volumetric level of producer support from 70% to 60% for the purposes of sections 9(1)(d), (2) and (3); 10(1)(c)(ii), (2), (5)(c); 12(2)(a)(iii), (c)(ii), (d), (e) and (f) of the *Natural Gas Marketing Regulation.*[53] The producer support mechanism is the procedure by which producers approve the pricing provisions of downstream contracts negotiated by the shippers with whom they have netback pricing arrangements in their contracts for supply of gas in the field. This mechanism was instituted so that producers have substantial input into the terms for selling their gas. To ensure widespread producer support for the contract terms negotiated by shippers and because of the diversity in the amount of gas that individual producers have under contract to each shipper, the producer support mechanism defines support both in terms of number of producers and volume of gas. When the producer support mechanism was established in 1986, the required support levels were set at 51% by number of producers and 70% by volume. Since that time there have been a number of significant mergers in the industry that have reduced the number of large producers required to reject a contract proposed by a shipper. In an

50. R.S.A. 1980, c. T-0.1.
51. Alta. Reg. 173/85.
52. R.S.A. 1980, c. P-37.
53. Alta. Reg. 358/86.

apparent effort to re-establish the initial balance of the producer support mechanism, the required support by volume has been reduced by 10%. Accordingly, future contracts submitted by shippers for producer approval will require the support of 51% of the producers by number and 60% by volume.

Alberta Regulation 313/89 effects a number of definitional changes and further adds, in part, provisions relating to the finding of producer support on the basis of "resale authorization provisions" and "arbitration authorization provisions" contained in producer-shipper contracts. This amendment also exempts from the operation of Part 2 (i.e., Producer Support for Downstream Pricing) of the *Natural Gas Marketing Act*[54] certain netback gas if sold by a producer to a shipper in accordance with a netback agreement and if certain other criteria are met (i.e., the criterion that the shipper must be authorized to resell netback gas delivered to him by other producers by reason of a finding of producer support). The amendment further exempts netback gas if the gas is delivered in Alberta for release to another person under a downstream contract and the price, or the basis or method for computing the price, of the gas delivered under the contract is determined by the Public Utilities Board pursuant to the *Gas Utilities Act*.[55]

(n) *Sulphur Emission Control Assistance Regulation*, Alta. Reg. 275/89

Alberta Regulation 275/89 gives to the Minister of Energy the authority to establish credits equal to 50% of the "eligible capital costs" of ERCB approved equipment relating to a processing plant as defined in the *Oil and Gas Conservation Act*[56] that, according to the ERCB, has a design capacity for sulphur equivalent inlet rate of not less than one and not more than five tonnes per day. This regulation also gives the Minister further authority to establish credits equal to 50% of the "eligible operating expenses" for approved equipment relating to any small sour gas plant. These credits are to be applied against the payment of money owing to the Crown under the *Natural Gas Royalty Regulations*.[57]

3. Proposed Changes

(a) Oil Sands Regulations

In April of this year Alberta Energy circulated to industry a draft *Oil Sands Regulations* reflecting "the culmination of a 3-year review with the industry on the direction oil sands tenure should take in Alberta". Three sets of proposals had been circulated for industry comment prior to the generation of the draft Regulations.

The stated objectives of the draft Regulations are to encourage the development of oil sand reserves and to promote the upgrading of crude bitumen within the province. Among other things the draft Regulations:

(i) broaden oil sands acquisition opportunities by recognizing a new policy of permitting disposition of oil sands rights through a public tender process and

54. R.S.A. 1980, c. N-2.8.
55. *Supra*, note 41.
56. R.S.A. 1980, c. O-5.
57. *Supra*, note 42.

by eliminating the preferential acquisition rights of petroleum and natural gas agreement holders effective two years after the Regulations come into effect;

(ii) increase annual permit and lease rentals to $3.50 per hectare;

(iii) lengthen the term of oil sands permits to 5 years, but authorize the Minister to refuse to issue a permittee a lease in respect of any part of his location which has not been subjected to a "minimum level of evaluation" (Alberta Energy has indicated that this minimum level of evaluation will be the drilling and logging of one well per section, with full core analysis on one well in each 4-section block);

(iv) prohibit the consolidation or division of permits, or the transfer of less than the permittee's entire interest in a permit;

(v) shorten the terms of oil sands leases to 15 years in the case of lease renewals and leases issued out of permits, and to 10 years in the case of "development" leases;

(vi) provide for automatic renewal of presently existing first term leases for a second term, subject to an escalating annual per hectare pre-production charge which may be reduced by a credit based on related crude bitumen production volumes;

(vii) modify the renewal provisions in respect of new leases and certain existing leases by requiring that a development plan have been agreed to by the lessee and the Minister and by specifying that the volume of the bitumen reserves to be covered by the renewal be formulaically determined on the basis of three criteria, being projected production volumes, dedication of production to upgrading within the province and investment in upgrading facilities within the province;

(viii) stipulate that the consent of the Minister must be obtained in conjunction with any transfer, surrender, consolidation or division of any lease; and

(ix) require a lessee to file a development plan whenever the Minister so requests, to commence or increase production if the Minister so directs in the second or subsequent term of a lease, and to evaluate and recover other minerals if the Minister so directs.

Alberta Energy has requested that comments on the draft Regulations be submitted by no later than June 30, 1990.

(b) Orphan Wells

As will be discussed later in this paper,[58] the ERCB has recently announced that it will take a firmer position on the transfer of well licences in order to reduce the number of wells deserted without having been properly abandoned and reclaimed. Proposed legislative changes with respect to the orphan well problem have been circulated for comment.[59] Regarding the *Oil and Gas Conservation Act*, a new section 18(11) has been proposed stating that:

> The consent of the Board to a transfer of licence after 31 January 1990 does not relieve the transferee [sic] of the responsibility of abandoning the well if the transferor [sic] does not do so.

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58. *Infra*, at 44.

59. See Energy Resources Conservation Board Report entitled "*Recommendations To Limit The Public Risk From Corporate Insolvencies Involving Inactive Wells*" dated December, 1989.

Further, an entirely new abandonment provision (i.e., section 20.1) has been suggested which would provide as follows:

(1) A well shall be abandoned by the licensee in accordance with the Regulations or when the Board so directs.

(2) A receiver, liquidator, trustee in bankruptcy, executor, administrator or other person acting in a representative capacity who assumes control and management of a business of an insolvent, deceased or incapacitated licensee shall

(a) advise the Board of his appointment,

(b) before being discharged, abandon all wells remaining licensed to the licensee, unless the Board's consent is otherwise obtained, and

(c) give the Board notice of any application for discharge.

(3) If the parties referred to in clauses (1) and (2) default in the obligation to abandon a well, upon being notified by the Board, the obligation to abandon a well falls upon the following parties in descending order:

(a) the remaining working interest owners with the obligation falling firstly on the working interest owner having the largest interest, and then on the working interest owner having the second largest interest, and so on;

(b) previous licensees of the well who were licensees after 31 January 1990;

(c) a lessee of the mineral rights;

(d) previous lessees of the mineral rights;

(e) the mineral owner.

(4) The costs of or incidental to the work of abandonment of the well to the satisfaction of the Board shall be determined by the Board and the costs plus a penalty of 25 per cent are a debt payable by the defaulting parties to the party which undertook the abandonment (including the Board).

Amendments would also be made to the *Energy Resources Conservation Act*[60] as a new section 34(2) is proposed providing that:

If this or any other Act authorizes the Board to make or issue an order or direction and a person refuses to comply with that order or direction of the Board, in addition to any other actions or proceedings it may be authorized to take, the Board may apply to the Court of Queen's Bench for an order requiring that person, his employees or agents to undertake the activity.

Finally, we have been advised that the Department of Energy is considering effecting changes to the *Mines and Minerals Act*[61] to the effect that:

(i) the obligation to abandon a well or to reclaim the surface survives the expiration of a Crown lease and the lessee shall indemnify the Crown for any costs associated with the abandonment or reclamation;

(ii) the transfer of a Crown lease will not relieve the transferor of this obligation if the transferee fails to honour it; and

(iii) a well located on a Crown lease will have to be abandoned within a set time after the lease expires.

(c) Bill 24, Mines and Minerals Amendment Act, 1990, 2d Sess., 22nd Legislature, 39 Elizabeth II

This Bill was given first reading on May 15, 1990 and will amend the *Mines and Minerals Act.* Among other matters, the amendments:

(i) increase the time period for application for reinstatement of an agreement from 30 days to 90 days after the date of surrender, cancellation or forfeiture;

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

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

(ii) remove references to the annual rentals for coal leases and quarriable mineral leases; and

(iii) revise the definitions of "exploration" and "exploration equipment".

(d) Bill 11, Petroleum Incentives Program Amendment Act, 1990, 2d. Sess., 22nd Legislature, 39 Elizabeth II

This Bill was given first reading on March 16, 1990, second reading on March 30, 1990 and was referred to committee on April 9, 1990. This Bill will amend the *Petroleum Incentives Program Act*[62] by repealing sections 2 and 3 and substituting the following:

> 2(1) The assets of the Alberta Petroleum Incentives Program Fund are transferred to the General Revenue Fund.
>
> (2) After the coming into force of this section,
>
> (a) a payment to meet any liability of the Government of Alberta under this Act shall be made from the General Revenue Fund, and
>
> (b) any money recovered or received by the Minister under this Act shall be paid into the General Revenue Fund.

(e) Proposed Amendments to the Alberta Corporate Tax Act, R.S.A. 1980, c.A-17 (as amended)

On November 6, 1989 Energy Minister Rick Orman announced changes to the Alberta Royalty Tax Credit ("ARTC") program, to take effect January 1, 1990. The ARTC program was instituted in May, 1974 to provide a mechanism whereby a certain percentage of Alberta Crown royalties are refunded, up to a maximum annual limit.

The new program provides for a long-term price sensitive ARTC which is determined by reference to the price of oil. There is a limit of $2,500,000 on the amount of Crown royalty base which is eligible for ARTC in each year, and the ARTC rate applicable to the Crown royalty base will be set quarterly, based on the average par price as determined by Alberta Energy for the previous calendar quarter. The ARTC rate ranges from a high of 85% at $100 or less per cubic metre to a low of 25% at $210 or more per cubic metre. The rate declines proportionately faster at prices exceeding $140 per cubic metre. Although the ARTC rate is adjusted quarterly, the program will continue to focus on the taxation year as a whole using a weighted average rate.

The changes to the ARTC program will be implemented by amendments to the *Corporate Income Tax Act*,[63] effective as of January 1, 1990.

(f) Alberta Gas Cost Allowance

On February 2, 1990 a joint industry task force (Canadian Petroleum Association, Independent Petroleum Association of Canada and Small Explorers & Producers Association of Canada) made recommendations to Alberta Energy with respect to

62. S.A., 1981, c. P-4.1.

63. R.S.A. 1980, c. A-17.

natural gas processing charges. The recommendations which the task force made to Rick Orman, Alberta's Minister of Energy include:

(a) the utilization of a modified Jumping Pound formula as the base methodology in calculating natural gas gathering and processing fees;

(b) a modification of the current method of Gas Cost Allowance allocation so as to require allocation of capital charges for Gas Cost Allowance purposes as follows,

  (i) the return on average capital and capital cost allowance be allocated on the basis of capacity used or capacity paid for under a custom fee arrangement, and

  (ii) operating cost recovery be allocated based on actual throughput;

(c) a dispute resolution and a fee negotiation process focusing on the encouragement of good faith negotiation; and

(d) the establishment of industry guidelines on processing fees charged to royalty owners.

At the time of writing, we have been advised that Alberta Energy is still reviewing the guidelines and recommendations set forth in the joint industry task force submission.

(g) Alberta Environment[64]

On March 15, 1990 Alberta Energy Minister Rick Orman and Environment Minister Ralph Klein announced that the Province of Alberta would launch a "broadly based consultative process" to develop a strategy for managing energy-related air emissions in the Province. This consultative process, which is to be jointly managed by Alberta's Energy and Environment Departments, will be designed to generate informed discussion on air emissions resulting from the production and use of energy in Alberta, including sulphur dioxide and "greenhouse gases" such as carbon dioxide, nitrogen oxides, volatile organic compounds and methane. It is hoped that these consultations will provide the basis for the development of a clean air strategy for Alberta.

The Ministers indicated that the consultative process would begin immediately with an initial series of discussions with "key stakeholder groups" to obtain their view and recommendations on how the consultations will be carried out and the timetable for completing them. Mr. Orman and Mr. Klein indicated that following the initial series of discussions and input they will release details on how the consultations will be carried out.

The Ministers noted that the consultative process will also include the establishment of an advisory group representing environmentalists, local government, public health authorities and the energy, transportation and utilities industries.

Among the steps proposed to be taken in this area will be the creation of a new administrative agency called the Natural Resources Conservation Board. Mr. Orman proposes to introduce the *Natural Resources Conservation Board Act* during the Spring sitting of the Legislature.

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64. Also, see page 45.

In a recently released document entitled "Mission Statement", Mr. Klein advised that he will be introducing a new and comprehensive environmental protection act to the Alberta Legislature "in the spring of 1990". This Act will apparently be entitled the *Alberta Environmental Protection and Enhancement Act.* Apparently it is Mr. Klein's intention to table this legislation in draft form to await public consultation, which the Minister anticipates will occur following the Legislature's spring session in 1990. After taking into account the views of Albertans expressed during the public consultation stage, Mr. Klein intends to introduce the final bill for approval by the Legislative Assembly. At time of writing, we have not received any further particulars on the Minister's new legislation. In 1987, The Review Panel on Environmental Law Enforcement issued An Action Plan for Environmental Law Enforcement in Alberta. At present, it is unknown if the new legislation will reflect these proposals.

II. REGULATORY DEVELOPMENTS

A. FEDERAL

1. National Energy Board (the "NEB")

(a) Decisions

(i) GH-5-88: NEB reasons for decision dated May, 1989 in the matter of an application dated November 27, 1987, as amended, made by Alberta and Southern Gas Co. Ltd.

Alberta and Southern Gas Co. Ltd. ("Alberta and Southern") pursuant to an application dated November 27, 1987 applied to amend previously granted Licence GL-99, to extend the term of, and to increase the volume authorized for export under such licence. In consideration whether to grant a licence to export gas, section 118 of the *National Energy Board Act*[65] requires the NEB to have regard to all considerations that appear relevant, and in particular requires that the NEB licence for export only those volumes of natural gas that do not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements in Canada, having regard to the trends in discovery in Canada. In complying with section 118 the NEB relied on its market-based procedure. Under the market-based procedure the NEB considers:

(a) complaints by Canadian users;
(b) an export impact assessment; and
(c) all other factors that the NEB considers relevant in its determination including, whether the proposed export will be of a net benefit to Canada.

The significant issue before the NEB was "the extent of Alberta and Southern's reliance upon supply under development contracts to support the proposed export and the weight the Board should give to the supply associated with such development contracts".[66]

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

66. *Re Alberta and Southern Gas Co.* (May 1989), GH-5-88 (N.E.B.) at 1.

A development contract is an agreement in which not all reserves are established at the time the contract is executed. Such a contract contemplates the development of potential reserves and assures the seller of a market for its future supplies and the buyer a supply of gas for its future requirements. A development contract requires a producer to dedicate specific lands in which it has established reserves and the right to explore for and develop new reserves. While none of the intervenors were opposed to the use of development contracts *per se*, Western Gas Marketing Limited, ICG Utilities (Ontario) Ltd., Consumers' Gas Company Ltd., and Union Gas Limited were opposed to the reliance on development contracts to support exports, primarily because potential buyers would be unable to compete for the reserves tied-up in the development contract, and the possibility that the same potential reserves would be relied on to support more than one export application.

Alberta and Southern conceded that there were risks inherent in relying on a development contract to support future exports, including the risk that not all producers would find adequate reserves to meet their contractual commitments. Nevertheless, this risk would be offset because some producers would find excess supplies and because Alberta and Southern has a right of first refusal for any amounts in excess of contracted volumes.

In deciding to extend the term of Alberta and Southern's existing licence to the year 2005, five years less than that requested, the NEB found that the development contract was "a sound business practice and an innovative practical means of ensuring future supply to meet requirements by encouraging the economic development of new reserves".[67] However, in relying on a development contract to support an export application the NEB concluded that it would expect that such a contract would be in "respect of lands that have both proven reserves and a reasonable potential for future discoveries of reserves".[68]

The NEB's decision to extend Alberta and Southern's licence also took into consideration the commercial necessity of the applicant by stating that "an export authorization should be of a duration that permits the applicant to pursue its business without adverse commercial consequences, but is not longer than commercially necessary".[69]

As noted above, the NEB's extension of Alberta and Southern's existing licence was five years less than requested. The primary reason for the reduced term was the NEB's concern that supply for the period beyond 2005 was not as secure as for the earlier period.

(ii) GH-3-89: NEB reasons for decision dated May, 1989 in the mater of an application dated January 12, 1989 made by Amoco Canada Petroleum Company Ltd.

The NEB's decision in this instance dealt with an application by Amoco Canada Petroleum Company Ltd. ("Amoco") pursuant to Part VI of the *National Energy Board Act* to export natural gas. The gas proposed for export by Amoco would be produced from the Cypress field in British Columbia and processed in field facilities

67. *Ibid.*, at page 6.
68. *Ibid.*, at page 6.
69. *Ibid.*, at page 15.

owned by Amoco and others in the same vicinity. The gas would then be transported on the Westcoast Energy Inc. system to Huntingdon, B.C., the export point for delivery into the system of the buyer, Washington Natural Gas Company ("Washington Natural"). The gas purchased by Washington Natural was intended to meet its supply requirements in northwestern Washington.

As with all applications requesting a licence to export gas from Canada the NEB, pursuant to section 118 of the Act, utilized its market-based procedure to determine whether Amoco's application should be granted. In relying on this procedure the NEB considered any complaints made regarding the application, an export impact assessment and a benefit-cost analysis. The NEB was satisfied that no party objected to the Amoco proposal and that, if granted, the licence would not adversely impact conservation or substitution patterns, gas prices or total production in Canada. In addition, the NEB was of the view that the proposed export would be in the Canadian public interest and that the Amoco/Washington Natural gas sale contract ensured cost recovery and flexibility over the term of the contract.

The licence issued by the NEB to Amoco was for a term of fifteen years commencing November 1, 1990 to export natural gas at Huntingdon, British Columbia. The volume of gas permitted for export under the licence was as follows:

(a) 704,000 cubic metres in one day;

(b) 257,000,000 cubic metres in any consecutive 12 month period ending on October 31; or

(c) 3,856,000,000 cubic metres during the term of the new licence.

(iii) GH-9-88: NEB reasons for decision dated June, 1989 in the matter of applications dated October 25, 1988 and September 16, 1988 made by ProGas Limited and Western Gas Marketing

The NEB received applications from ProGas Limited ("ProGas"), and Western Gas Marketing Limited ("WGML"), to export natural gas to the United States. From those applications the NEB issued GL-98 to ProGas, and Licence GL-83 to WGML. At this hearing both ProGas and WGML requested that the terms of their licences be extended and the volume of natural gas authorized for export be increased.

In granting the applications and thereby amending the licences held by ProGas and WGML, the NEB extended the term of Licence GL-98 by six years and increased the amount to be exported under such licence by 1.5 trillion cubic feet. Licence GL-83 which authorizes exports to Boundary Gas Inc. was amended by extending the term of such licence from October, 1996 to January, 2003 and by increasing the exportable volume by 222.6 billion cubic feet.

It is to be noted that the NEB was unwilling to add a provision to the amended licence to allow for the export of underdeliveries over an extended period of time necessary to export the authorized term quantity. A minimal amount of discussion on this point was included in the NEB's decision.

(iv) GH-8-88: NEB reasons for decision dated June, 1989 in the matter of applications dated September 13, 14, 15 and 16, 1988 made by Canterra Energy Ltd., Norcen Energy Resources Limited, Poco Petroleums Ltd., Western Gas Marketing Limited, Shell Canada Limited and Vector Energy Inc.

In September, 1988 Canterra Energy Ltd. ("Canterra"), Norcen Energy Resources Limited ("Norcen"), Poco Petroleums Ltd. ("Poco") and Western Gas Marketing Limited ("WGML") requested NEB approval to export natural gas to Consumers Power Company ("Consumers") and Midland Cogeneration Venture Limited Partnership ("Midland"). At the same time Shell Canada Limited ("Shell") applied for an amendment of gas export Licence GL-100 to provide sales to Consumers and Midland. The licences requested supported the facilities requested by TransCanada PipeLines Limited in an application considered under GH-4-88. Consumers is a combined electric and gas utility supplying residential, commercial and industrial customers, while Midland is a partnership that was organized to construct and operate a gas-fired cogeneration facility in Midland, Michigan.

By application dated August, 1988 Vector Energy Inc. ("Vector"), as agent for seven Alberta natural gas producers, applied for a twenty year licence to export natural gas to fuel a cogeneration plant in Pittsfield, Massachusetts. This application was heard with the aforementioned applications.

The NEB utilized its market-based procedure in assessing the export applications requested. The NEB authorized licences for Canterra, Norcen, Poco, Shell and WGML to export 771 billion cubic feet of natural gas over periods up to sixteen years. In its decision the NEB, with the exception of Poco's application, was satisfied with the adequacy of the gas supply arrangements made by the applicants. In Poco's case the NEB was not convinced that Poco had sufficient dedicated reserves to supply the project over the entire term. Consequently, it granted Poco a licence with a term of twelve years rather than the requested sixteen year term and a term volume of 2,715 million cubic metres rather than the requested 3,749 million cubic metres.

The licences granted were subject to the condition that the annual exports in Midland not exceed those to Consumers. In the benefit-cost analysis used to evaluate the proposed exports the NEB concluded that the combined exports to Consumers and Midland generated at a net benefit to Canada. However, on a stand-alone basis the proposed sales to Midland would not meet this test. Consequently the NEB issued licences with respect to the sales to Midland on the condition that such sales be linked to the sales to Consumers.

The NEB denied Vector's export application because it was not satisfied that it was in the public interest. In assessing the evidence the NEB was not satisfied with:

(a) the contractual arrangements in support of Vector's application; specifically the NEB was not satisfied that Vector was acting as the agent of Wainoco Oil Corporation ("Wainoco") since Wainoco had not executed the Agency Agreement executed by the other producers of whose behalf Vector was acting and the existence of a separate sales contract between Wainoco and Altresco Pittsfield Incorporated;

(b) Vector's gas supply; and

(c) the results of the NEB's benefit-cost analysis which indicated that Vector's proposed export would not recover the associated costs in Canada, primarily because of the unattractive pricing terms in the gas sales contract.

In light of the NEB's decision to discontinue the use of benefit-cost analysis in assessing export applications,[70] as later discussed, the NEB amended the gas export licences issued to Canterra, Norcen, Poco, Shell and WGML by replacing a condition in the licences that specified that annual exports to Midland may not exceed the exports to Consumers. Instead, such condition was replaced with a condition that allowed the NEB to impose such terms and conditions as are necessary to ensure the matching of volumes over the term of the licences.

Vector's application was re-heard pursuant to Hearing Order GH-6-89. However, to date, no decision has been issued by the NEB.

(v) GHW-1-89: NEB reasons for decision dated June, 1989 in the matter of an application dated April 11, 1989 made by Foothills PipeLines (Alta.) Ltd.

This decision addressed an application dated April 11, 1989 by Foothills Pipe Lines (Alta.) Ltd. ("Foothills") for an order pursuant to section 58 of the *National Energy Board Act* exempting Foothills from the provisions of paragraph 30(1)(a), subsection 30(2) and section 31 of the Act, in respect of facilities proposed by Foothills to increase the capacity of the Eastern Leg of Phase 1 of the Alaska Natural Gas Transportation System. The facilities Foothills proposed to install were decompression/recompression facilities located adjacent to the Empress II extraction plant and a new interconnection with the NOVA pipeline system near the NOVA Princess compressor station. The proposed facilities were intended to provide, *inter alia,* increased transportation of gas for NOVA on the pipeline in Zone 6 by removing a bottleneck in such pipeline. In its application Foothills also applied for approval to include the actual costs of constructing the proposed facilities in its Zone 6 rate base.

The NEB approved Foothills' application, thereby authorizing the construction and operation of the proposed facilities and permitted Foothills to include the cost in its Zone 6 rate base. In reaching this decision the NEB found that Foothills' proposal would adhere to the policy of the Government of Alberta that "whenever possible, gas leaving the province will be stripped of heavier hydrocarbons to the maximum extent feasible"[71] by diverting the gas leaving the Province of Alberta from the Foothills pipeline through the Empress II extraction plant and the alternative options would not be suitable for either technical or economic reasons. Further, the NEB concluded that although Foothills was unable to provide contracts, that would support this major facility addition, the provision of "a certain amount of advance capability on the Eastern Leg would be in the public interest"[72] and that the costs of the proposed facilities were modest relative to the potential benefits that they could provide. In deciding, to permit construction costs of the proposed facilities to be included in Foothills Zone 6 rate, the NEB noted "that most of the interested parties were in favour of this treatment of the costs".[73]

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70. National Energy Board Reasons for Decision in the Matter of a Review of Certain Aspects of the Market-Based Procedure, held by way of written submissions pursuant to Section 21 of the *National Energy Board Act* GHW-4-89 March, 1990.

71. National Energy Board Reasons for Decision in the Matter of an Application dated April 11, 1989 made by Foothills PipeLines (Alta.) Ltd. for an Order pursuant to Section 58 of the Act requesting an exemption from Paragraph 30(1)(a), Subsection 30(2) and Section 31 of the *National Energy Board Act*, GHW-1-89, June, 1989, at 8.

72. *Ibid.*, at 9.

73. *Ibid.*, at 9.

(vi) RH-1-88: NEB reasons for decision dated June, 1989 in the matter of an application made by TransCanada PipeLines Limited

The NEB decision that addressed Phase I of this hearing was included in last year's paper. The major issue in the Phase I hearing was whether the prohibition against self-displacement by a distributor should be eliminated. In its decision the NEB decided to eliminate the prohibition against self-displacement effective November 1, 1991. There were several reasons given for the NEB's decision to eliminate such prohibition, including the fact that it restricted the distributor's access to transportation services and that continuation of the NEB's policy prohibiting self-displacement could delay achieving a full market-sensitive pricing regime in conjunction with non-discriminatory access to gas supplies and pipeline capacity.

The Phase II hearing dealt with cost of service issues and toll design and tariff matters not covered in Phase I. The Phase II hearing did not address any issue approaching the significance of the elimination of self-displacement. Nevertheless, some of the more salient items addressed by the NEB at this phase were; TransCanada PipeLines Limited's ("TCPL") revenue requirement for 1989, cost of capital, tolls, and capacity brokering;

(a) Revenue Requirement - The NEB approved a revenue requirement for 1989 of $836 million compared with TCPL's forecast requirement of $890 million. The reduction of $54 million was due in large part to excess revenues collected by TCPL from the interim tolls in effect during 1988 and the first half of 1989. Other factors contributing to the reduction were downward adjustments made to TCPL's forecast in respect of transmission by others costs, income taxes, return on rate base and transportation revenue requirements;

(b) Cost of Capital - TCPL applied to maintain its common equity ratio of 30% for the 1988 test year and to increase the ratio to 32.5% in 1989. TCPL contended that, among other things, the increase to 32.5% was necessitated to maintain TCPL's common equity ratio relative to other major Canadian utilities with which TCPL competes for capital. In assessing TCPL's common equity ratio the NEB relied, as it has in previous TCPL toll cases, on three (3) factors, namely,

(1) the business risks faced by TCPL's utility operations,

(2) the maintenance of an appropriate balance between the debt and equity elements of the deemed capitalization, and

(3) the maintenance of an appropriate balance between the equity financing attributed to the utility through the deeming process and that portion of the actual consolidated financing which is left to support TCPL's non-utility operations.[74]

In applying these factors to TCPL's proposal for an increase to 32.5% the NEB found that no change in the present deemed common equity component of 30% was warranted and therefore denied TCPL's request.

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74. National Energy Board Reasons for Decision in the Matter of an Application made by Trans-Canada PipeLines Limited for certain orders respecting tolls under Sections 50, 51 and 53 of the *National Energy Board Act*, RH-1-88 Phase II, June 1989, at 11.

The NEB approved rates of return on equity of 13.25% for 1988 and 13.75% for 1989. TCPL requested a rate of return of 14.50% for 1989;

(c) Tolls - The new tolls approved by the NEB for the transportation of gas to Eastern Canada were 32% lower than the tolls in effect since 1987 and 11% lower than the tolls applied for by TCPL; and

(d) Capacity Brokering - Capacity brokering in its broadest form is "any mechanism by which entitlements to transportation capacity can be allocated to others without the consent of the transporter"[75] and can be broken down into the brokering component and the assignment component. The brokering component involves the allocation of contracted capacity entitlements for the toll approved by the NEB plus a premium, whereas the assignment component involves an assignment of contracted but unused capacity entitlements.

The NEB decided not to implement a capacity brokering mechanism because it viewed brokering for profit as "contrary to sound market principles, as such a mechanism would tend to extract monopoly profits in the marketing of a scarce resource"[76] and any added costs to the gas marketing system would be borne by producers, shippers and consumers reliant on the system. However, the NEB decided to permit assignments at a discount negotiated between the assignor and assignee provided that the toll approved by the NEB is paid to TCPL. The NEB stated that assignments create an incentive to maximize utilization of TCPL's system capacity which in turn benefits all system users.

(vii) GH-10-88: NEB reasons for decision dated August, 1989 in the matter of applications by Esso Resources Canada Limited, Shell Canada Limited and Gulf Canada Resources Limited

Applications by Esso Resources Canada Limited ("Esso"), Shell Canada Limited ("Shell") and Gulf Canada Resources Limited ("Gulf") were the subject of this significant and historic decision by the NEB that authorized exports of natural gas from the MacKenzie Delta.

With regard to the complaints procedure the NEB, along with most of the parties to the hearing, realized that without specific contracts, which none of the applicants had at the time the applications were made, the procedure could not operate as it was envisioned. However, the NEB satisfied the objectives of the complaints procedure by including as a condition in the licence issued to the applicants that when gas sales contracts related to the approved exports are filed with the NEB, the licensees shall notify all parties to the hearing of such filing. The interested parties will then have sixty days from the date of filing such contracts to register complaints that they have not been given an opportunity to purchase gas on terms and conditions, including price, similar to those under which the gas would be exported.

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75. *Ibid.*, at 57.

76. *Ibid.*, at 58.

The NEB agreed with the results of the export impact assessment presented by the applicants in support of their application. The assessment concluded that the proposed export would have a small downward impact on domestic natural gas prices and that the applied for export volumes would not cause Canadians difficulty in meeting their future energy requirements at fair market prices.

The benefit-cost analysis conducted by the NEB concluded that there were two major uncertainties in the applications, namely:

(a) the lack of export sales contracts; and

(b) the absence of detailed information on the pipeline that would transport gas destined for export.

Nevertheless the NEB was of the view that, despite the absence of firm contracts, there was a "reasonable expectation that U.S. buyers would have sufficient markets to accommodate the level of exports contemplated in the applications", and that access to export markets was essential to the development of MacKenzie Delta reserves.

The NEB heard from The Dene Nation and the Metis Association of the Northwest Territories who requested that the export licences be withheld until land claims in the area were settled. While recognizing the importance of land claim matters, the NEB was not convinced that the approval of gas export licences would prejudice the settlement of the Dene/Metis claims. This finding was supported by the opinion of a broad spectrum of northerners including the Yukon government and a number of federal members of parliament.

The granting of the applied for exports is a significant step in frontier development. However, it must be recognized that the applications before the NEB did not include a proposal to transport gas from the MacKenzie Delta. Foothills Pipelines (Yukon) Ltd. and Polar Gas Limited have both expressed an interest in constructing a pipeline from the north. Before Arctic gas can actually go to markets in southern Canada and the United States much work remains to be done in concluding formal sales contracts as well as obtaining approval for and constructing a major new pipeline to transport MacKenzie Delta gas into the North American gas grid.

While there were other issues before the NEB the above discussion focuses on the more salient ones. The NEB issued licences to the applicants for the requested volumes of 9.2 TCF (aggregate) over the applied-for twenty year term.

(viii)RH-1-89 and RH-2-89: NEB reasons for decision dated September, 1989 and January, 1990 in the matter of an application made by Westcoast Energy Inc.

In June, 1989, the NEB held Phase 1 of a hearing to examine the tolls to be charged by Westcoast Energy Inc. ("Westcoast") for the period November 1, 1989 to December 31, 1989 and for the years 1990 and 1991. The Phase 1 hearing included an examination of Westcoast's capacity allocation policy, self-displacement, queuing procedures, renewal rights, and other toll design and tariff issues. The Phase 2 hearing, held in October, 1989, considered issues such as rate base, cost of service and rate of return.

Phase 1 Hearing: RH-1-89

(a) Capacity Allocation – Westcoast's problems regarding capacity allocation on its system emanated from the claim of *force majeure* by Northwest Pipeline Corporation ("Northwest") to suspend its obligations to purchase gas for the export market. The agreement between Westcoast and Northwest was to expire October 31, 1989. However, an early termination of that agreement occurred effective October 13, 1988 leaving available the capacity previously contracted by Northwest. As a result of Northwest's repudiation, Westcoast introduced an interim policy to allocate the capacity previously allocated to Northwest. Under this policy requests for service expired October 31, 1989 unless the party making the request could demonstrate the existence of a *bona fide* project (i.e., both a firm market and a firm supply). Virtually all of the capacity used by Northwest was taken by the British Columbia Petroleum Corporation and several other shippers, all of which were referred to during the hearing as the "550 shippers". With respect to capacity available on November 1, 1989, the NEB concluded that Westcoast's proposal to hold an open season was reasonable and that priority during the open season should first be given to any of the 550 shippers that could demonstrate a ripe project by July 5, 1989, secondly to new shippers servicing the export market who could demonstrate the existence of a ripe project by the end of the open season and finally to new shippers demonstrating either a firm supply or firm market.

The NEB also decided on the allocation of the capacity currently used to accommodate sales of British Columbia Petroleum Corporation gas by Westcoast to BC Gas Inc. ("BC Gas") and Inland Natural Gas Co. Ltd. ("Inland") whose gas sales contracts with Westcoast expire October 31, 1991. Subject to some modifications the NEB decided to accept Westcoast's proposal to reserve the available capacity for ripe projects serving the core market. Further, the NEB accepted the proposal of BC Gas and Inland that they be given priority to any remaining capacity as at May 1, 1991 up to a maximum of their operating demand volumes at that time;

(b) Queuing Procedures - In its RH-2-87 Westcoast reasons for decision, the NEB directed Westcoast to develop a capacity allocation policy and to submit the policy to the NEB for approval. In response to the NEB's directive, Westcoast filed extensive queuing procedures that were consistent with the guidelines established for the system of Foothills Pipe Lines (Yukon) Ltd. In accepting Westcoast's proposed queuing procedure the NEB indicated that it would ensure fair and equitable access to Westcoast's system capacity;

(c) Renewal Rights - The NEB received submissions which indicated that while renewal rights were not in Westcoast's tariff, such rights had been granted to shippers with firm service contracts since 1985. Westcoast proposed that all existing shippers should have renewal rights provided they can demonstrate either a firm supply or a firm market. The NEB accepted Westcoast's proposal and also agreed with Westcoast that in situations where capacity is allocated on an interim basis, such allocation should not be subject to an automatic right of renewal, but subject to capacity becoming available;

(d) Self-Displacement - Self-displacement occurs "when a distributor replaces any portion of its currently contracted firm gas supply with an alternate supply or makes any other arrangement that accomplishes the same end".[77] In

77. National Energy Board Reasons for Decision in the Matter of an Application made by Westcoast Energy Inc. for Orders respecting tolls under Sections 59, 60, 62 and 63 of the *National Energy Board Act*, RH-2-89, Jan. 1990, at (ix).

its RH-2-87 reasons for decision the NEB indicated that Westcoast distributors should not be allowed to displace their contracted firm supplies. Since that ruling the NEB has, however, removed the regulatory prohibition against self-displacement, effective November 1, 1989, pursuant to its decision in Phase I of Hearing Order RH-1-88.

Notwithstanding the arguments of the Canadian Petroleum Association and the Independent Petroleum Association of Canada ("IPAC") that self-displacement on the Westcoast system would result in contract abrogation, the NEB, in rescinding its policy of prohibition against self-displacement on the Westcoast system effective November 1, 1991, stated that the "principles of fairness in relation to access to transportation services and an orderly transition to a market sensitive price regime, as espoused in its RH-1-88 Trans Canada Reasons for Decision, apply equally to the Westcoast system";[78] and

(e) Promotional Tolls for Service to the Vancouver Island Pipeline Project – Westcoast requested the NEB to approve a discount from the normal toll paid to other shippers for the first three years of the project. The rationale for the reduced toll was that it was necessary to allow time for the market which would be served by the new pipeline to develop a system load that would make the project economically viable. The NEB denied Westcoast's proposal for such a toll on the basis that it was not convinced that the project required the assistance of a promotional toll. The NEB stated that the intent of section 62 of the *National Energy Board Act* is such that there must be compelling reasons to lead the NEB to approve a promotional toll and such reasons were not evident at this hearing.

The above matters represented some of the NEB's findings in this hearing. Other matters ruled on by the NEB included throughput, transportation, storage tolls and interruptible tolls.

Phase 2 Hearing: RH-2-89

Conducted in accordance with the procedures set out in Hearing Order RH-2-90, this hearing was held to establish the revenue requirement for the 1990 test year and to determine the appropriate disposition of existing deferral accounts. The NEB's decision was issued December 19, 1989 without reasons (the reasons for decision were released in March, 1990), to avoid the necessity of establishing interim tolls effective January 1, 1990 and to provide Westcoast with ample opportunity to review the NEB's decision and file its toll application for the 1991 test year by July 1, 1990.

The NEB, after examining Westcoast's requested rate base, revenue requirement and rate of return for the 1990 test year:

(a) directed Westcoast to determine its 1990 test year revenue requirement and cost of service based on the NEB's decision of December, 1989 respecting Westcoast's Phase II application and all other matters raised in connection with the RH-2-89 toll hearing (this decision was issued without the attendant Reasons for Decision in an attempt to avoid the requirement for interim tolls on January 1, 1990);

(b) approved the applied for common equity ratio of 35% for the test year; and

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78. *Ibid.*, at 15.

(c) found that a rate of return on common equity of 13.25% was fair for the test year, which was a reduction of 50 basis points from the previously approved rate of 13.75%.

In addition, the NEB directed Westcoast to file future toll applications no later than six months prior to the commencement of the next test year.

In respect of deferral accounts the NEB approved Westcoast's proposal that the existing deferral account balances be disposed of by either debiting or crediting the 1990 cost of service of each of the four toll zones in the Westcoast system, namely:

(a) Zone 1 - Gathering Facilities;
(b) Zone 2 - Processing Plants (which is divided into two functions, liquid extraction and treatment);
(c) Zone 3 - Transportation North; and
(d) Zone 4 - Transportation South.

Also, the NEB directed Westcoast, as a result of its RH-1-89 Phase I decision, to discontinue deferral accounts in respect of the Laprise Off-Load Project, Authorized Overrun Revenues, Interruptible Sales and Service Revenues, Interruptible Transportation Storage Service Revenue Injection and Firm Transportation Storage Service Revenue.

(ix) RHW-1-89: NEB reasons for decision dated November, 1989 in the matter of a study entitled "A Toll Design Study and Recommendations in Response to NEB Reasons for Decision RH-4-86"

In its decision dated June, 1987 emanating from Board Order RH-4-86, the NEB directed Interprovincial Pipe Line Company ("IPL"), a division of Interhome Energy Inc., to undertake and to submit to the NEB several studies regarding IPL's toll design. In response to the NEB's directive on June 29, 1988, IPL filed "A Toll Design Study and Recommendations in Response to NEB Reasons for Decision RH-4-86". The primary focus of IPL's study was to propose a surcharge methodology for the movement of various grades of crude oil, natural gas liquids and refined products. In its reasons for decision RHW-1-89 the NEB examined each of IPL's proposals in regard to the surcharge methodology.

The NEB agreed almost entirely with IPL's proposal, including IPL's plan to roll-in the cost of special facilities to the general rate base from which all surcharges are determined. Special facilities are those facilities installed to meet the unique requirements of a particular commodity, "over and above those required to ship light crude oil, and whose identifiable costs can be directly attributed to a specific commodity".[79] Most of the interested parties at this hearing opposed IPL's treatment of special facilities since, prior to IPL's proposal, the cost of special facilities to ship natural gas liquids and refined products were included in the surcharges for those commodities separate from the general revenue requirement to be paid by all shippers. The primary argument presented by those parties opposing the rolling-in of the cost of the special facilities to the general rate base was the assertion that the concepts of user-pay and cost causality dictate that the costs of special facilities be charged specifically to those commodities requiring the additional facilities. In approving the integration

79. *Interprovincial Pipe Line Co.* (November 1989) RHW-1-89 (N.E.B.) at 11.

of the cost of special facilities and operating costs into the general revenue requirement the NEB recognized that while cost causality and user-pay are important concepts in toll design, the actual special facility costs in IPL's line were not readily identifiable or assignable to specific commodities. The NEB found that IPL's proposed surcharge methodology did not depart from the concept of cost causality "but incorporates it in a different fashion than the current method of using actual facilities and operating costs to produce additive surcharges".[80]

Following the NEB's decision to approve IPL's proposal, IPAC requested that the NEB review its decision regarding IPL's tolling methodology and in particular the proposed treatment of charges for special facilities required to transport natural gas liquids and refined products. The NEB, however, rejected IPAC's request for a review.

(x) GH-1-89: NEB reasons for decision dated December, 1989 in the matter of an application dated December 29, 1988 made by TransCanada PipeLines Limited, and in the matter of an application dated January 31, 1989 made by Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, an application dated February 14, 1989 by Indeck Gas Supply Corporation, an application dated February 15, 1989 by Western Gas Marketing Limited, and an application dated February 14, 1989 by Western Gas Marketing Limited as agent for TransCanada PipeLines Limited, and in the matter of an application dated February 10, 1989 by ICG Utilities (Ontario) Ltd., and in the matter of an application dated November 15, 1988 by ProGas Limited, and in the matter of an application dated November 21, 1988 by Shell Canada Limited.

This comprehensive and contentious two volume decision was delivered by the NEB in late 1989, addressing an application by TransCanada PipeLines Limited TCPL to expand its pipeline system in order to increase its capacity to serve expanding domestic and export markets, together with 14 applications for gas export licences from shippers who would use the expanded TCPL pipeline to export natural gas (as is pointed out later only eight of these applications were considered by the NEB). After a preliminary review of TCPL's application the NEB decided to examine both the pipeline expansion application and the export applications at the same time, since many common issues such as supply, markets and contracts were involved. Our review will be divided into two parts, namely TCPL' pipeline expansion application and the associated gas exports applications, including subsequent applications for review.

A. TCPL's Pipeline Expansion Application

TCPL's application for additional facilities, which was the third in a recent series submitted by TCPL to expand its pipeline system, included 495 km of pipeline, new compression facilities and additional metering facilities. The new facilities would enable TCPL to meet projected sales and transportation requirements for the 1990/91 contract year, including firm service contracts, changes in load factors for some existing customers and firm requirements that started late in the 1989/90 contract

80. *Ibid.*, at 13.

year. After reviewing the supply in respect of new requests for service associated with the proposed expansion and the total supply of natural gas available to the TCPL system, the NEB was satisfied as to the existence of adequate reserves and productive capacity to support the additional facilities requested by TCPL. In addition, the NEB was satisfied that TCPL's application satisfied all other criteria necessary to grant a Certificate of Public Convenience and Necessity under section 52 of the *National Energy Board Act.*

A contentious matter that arose from the NEB's decision was its denial of TCPL's request for a certificate in respect of the Gananoqe Extension in eastern Ontario and associated metering facilities. The proposed Grananoque extension was to be a new lateral pipeline to extend for 25.5 km from Gananoque to the Canada/U.S. border near Wolfe Island in the St. Lawrence River. It would be used to transport exports to Niagara Mohawk Power Corporation ("Niagara"). The NEB denied TCPL's application for a certificate in respect of the Gananoque Extension because TCPL's export licence application for a proposed sale to Niagara was denied.

B. Associated Gas Export Applications

In conjunction with the TCPL hearing regarding additional facilities, the NEB also heard eight applications for the export of natural gas. Although fourteen applications for export were filed, only eight of these applications met the filing requirements set out in the *National Energy Board Part VI Regulations* and the July, 1987 *Surplus Determination Procedures Report.* As well, one of the eight applications made by Direct Energy Marketing Limited ("Direct") did not rely on the facilities requested by TCPL in the GH-1-89 proceedings but rather, relied on the associated facilities of the TCPL system approved in the GH-4-88 decision. Direct's application was included in this proceeding only because its application was not completed in time for the GH-8-88 hearing as was originally intended. The NEB denied the applications by Direct, WGML, as agent for TCPL, Indeck Gas Supply Corporation ("Indeck") and Shell. The total amount of exports denied was 533 billion cubic feet. The NEB granted the applications by Amoco, Consolidated Edison Company of New York, ICG Utilities (Ontario) Ltd., ProGas Limited, and WGML. The NEB's concerns with each of the denied applications varied, but generally they could be grouped into three areas, namely;

(a) the adequacy of gas supply supporting the applied-for export licences;
(b) the flexibility of the contractual arrangements to ensure market-sensitive pricing over the full term of the export; and
(c) the likelihood that the applied-for exports would not generate net benefits to Canada, that is, unsatisfactory benefit-cost ratios.

Arising from the NEB's decision was a series of requests for leave to appeal the decision to the Federal Court of Canada. These requests were based on claims that the NEB breached the principles of natural justice and procedural fairness by basing its decision on evidence that was not entered in the hearing.

At approximately the same time that the NEB released its decisions in respect of the TCPL expansion and the associated export applications, the NEB announced that it would hold a public hearing to review certain aspects of the market-based procedure used in assessing export applications, particularly the role of benefit-cost analysis.

Under Order GH-1-90 the NEB conducted a hearing beginning on April 23, 1990 to consider four applications for review arising from the NEB's decision in GH-1-89 to deny certain applications. Applications for review were submitted by Direct, WGML as agent for TCPL, Indeck and Shell (Niagara also applied for a review of the WGML application). The NEB conducted this review in light of its decision of March 15, 1990 to discontinue its use of benefit-cost analysis in considering applications for export licenses. Pursuant to this hearing the NEB issued export licences to all of the aforementioned companies with written reasons to follow. These reasons have not yet been released.

(b) Published Policy Statements

(i) NEB reasons for decision dated November, 1989 in the matter of the proposed amendment to export impact assessment filing requirements

In its decision of July, 1987 "Review of Natural Gas Surplus Determination Procedures",[81] the NEB established that an applicant for a natural gas export licence must file an export impact assessment ("EIA"). Thus an EIA became an integral part of the market-based procedure used by the NEB in assessing export applications. In its 1987 decision the NEB stated that:[82]

> The purpose of the impact assessment will be to allow the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.

Experience with the EIA indicated that:

(a) it is difficult to measure the impacts of small export projects; and
(b) there was uncertainty on the part of applicants seeking export licences about how best to satisfy the EIA requirements.

In an effort to address these issues the NEB, on September 7, 1989, issued a proposed amendment to the EIA filing requirements and invited parties to comment on the proposal and the issues it was designed to address.

The NEB received submissions from several interested parties and for the most part their submissions did not support the proposal presented by the NEB. The views expressed by the submittors suggested that the EIA was redundant since the information contained would also be included in the complaints procedure or the benefit-cost analysis used by the NEB in assessing export applications. In addition, several submittors contended that the EIA should be eliminated from the NEB's market-based procedure because the EIA requirement is inconsistent with a deregulated market. They submitted that in an open market competitive forces would be sufficient to produce the supply needed to meet demand.

After considering the views of the submittors the NEB nevertheless decided to retain the EIA as part of its market-based procedure for licencing exports. The NEB was of the view that the presence of competition in the marketplace does not forego the possibility that "there can never be problems as markets adjust to changing supply and demand conditions"[83] and indeed market failure can occur. Also, the NEB was

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81. National Energy Board Reasons for Decision in the Matter of Review of Natural Gas Surplus Determination Procedures, July, 1987.

82. National Energy Board Reasons for Decision in the Matter of the Proposed Amendment to Export Impact Assessment Filing Requirements, November, 1989, at 1.

83. *Ibid.*, at 4.

not convinced that the information gleaned from an EIA could be adequately ascertained by other means already in place.

While retaining the EIA, the NEB decided that it would no longer require applicants for gas export licences to file an EIA as part of their applications. Instead, the NEB would periodically produce an EIA using several projections of exports. This EIA would address the effects that increased exports would have on price, supply and demand in Canada. This assessment would be available in export licence hearings to determine whether the proposed exports would cause Canadians difficulty in meeting future energy requirements at fair prices. Gas export applicants would have the option of using the NEB's EIA or submitting their own.

(ii) GHW-3-89:NEB reasons for decision dated January, 1990 in the matter of information required to be provided by TransCanada PipeLines Limited in support of its 1991/92 and 1992/93 facilities applications.

In June, 1989 TCPL applied to the NEB to construct pipeline facilities for expanded service to commence in November of 1991 and 1992. Several shippers, including Union Gas Limited ("Union") requested that TCPL include their volumes in this application to the NEB. TCPL, however, excluded the volumes of some prospective shippers, including Union, because they failed to provide TCPL with evidence that they had sufficient gas supply for the service requested. Union subsequently applied to the NEB, requesting that it order TCPL to include Union's request for service in its application. The NEB denied Union's request on the basis that TCPL's application for pipeline facilities was its prerogative and could not be ordered by the NEB. Following denial of Union's applications, the NEB held a hearing in writing, which is the subject of this decision, to obtain the views of interested parties and to clarify the gas supply information TCPL should provide in support of its 1991 and 1992 facilities application.

The gas supply information required to be filed by an applicant that requests NEB approval of a pipeline application is listed in paragraphs 3(a) and 3(b) of Part I of Schedule II of the draft *National Energy Board Rules of Practice and Procedure* dated April 21, 1987 (the "Rules"). The information required pursuant to these paragraphs are commonly broken down into two categories, namely:

(a) project-specific supply information; and

(b) overall supply information.

Project-specific supply information is sought by the NEB as a means of confirming that a prospective shipper actually has the supply which it claims to have. The purpose of this requirement is to reduce the possibility that capacity on the new pipeline system will be under utilized. A key issue regarding project-specific supply information in GHW-3-89 was the extent to which flexibility should be provided with respect to the timing and content of submissions regarding such information. The NEB reviewed two divergent views on the issue of flexibility. One was that flexibility should not be allowed in project-specific supply information, since clearly demonstrated long-term supply arrangements are the only effective way to ensure that supply will be avaialble to serve particular markets and thus justify construction of facilities. The other view advocated flexibility and submitted that rigid adherence to existing requirements for project-specific long term supply information impedes the efficient operation of a market economy and is inconsistent with deregulation of the gas industry. The NEB decided not to allow flexibility in providing project-specific supply information, except in cases where the incremental volumes represent normal growth in a shipper's existing market.

With respect to overall supply information, the NEB viewed this as being necessary and complementary to project-specific supply information. TCPL must provide evidence that there is, or will be, adequate natural gas supply to ensure sufficient utilization of its proposed expansion over the long term. The overall supply assessment should consider all potential supply sources that could reasonably be connected to TCPL's system, and the domestic and export demand for Canadian gas that could be expected to be served by such supply. The NEB concluded that this overall assessment should also be part of the TCPL supporting material and subject to cross-examination at the hearing of the facilities application.

(iii) GHW-4-89: NEB reasons for decision dated March, 1990 in the matter of a review of certain aspects of the market-based procedure

Section 118 of the *National Energy Board Act* outlines the factors which the NEB should consider when deciding whether or not to issue an export licence. In 1987 the NEB reviewed the procedures it had been using to comply with section 118 of the Act and introduced a new market-based procedure which it would rely on in assessing future export applications. Included in this procedure was a social benefit-cost analysis which was intended to quantify the net benefits to Canada of the proposed export. A benefit-cost analysis compares a stream of forecast revenues with a stream of forecast costs, both expressed in present value terms. The benefit-cost analysis component of the market-based procedure came under close scrutiny by producers and shippers in Western Canada following the decision of the NEB in GH-1-89 to deny four applications to export natural gas to the United States.[84] The four applications that were denied were made by:

(a) Direct for its sale to Consolidated Fuel Company for use in a cogeneration facility owned by Arrowhead Cogeneration Company Limited;
(b) WGML, as agent for TCPL, for exports to Niagara Mohawk Power Corporation for system supply;
(c) Indeck for exports to two cogeneration plants in New York; and
(d) Shell for its sale to Salmon Resources Ltd. for use in a cogeneration facility owned by Cogen Energy Technology Inc.

84. National Energy Board Reasons for Decisions in the matter of an application dated December 29, 1988, as amended, made by TransCanada PipeLines Limited, pursuant to Parts III and IV of the *National Energy Board Act* for a certificate in respect of certain proposed facilities, and in the matter of an application dated January 31, 1989 made by Amoco Canada Petroleum Company Ltd. and Consolidated Edison Company of New York, Inc., an application dated October 12, 1988 by Direct Energy Marketing Limited, an application dated February 14, 1989, as amended by Indeck Gas Supply Corporation, an application dated February 15, 1989 by Western Gas Marketing Limited, and an application dated February 14, 1989 by Western Gas Marketing Limited, as agent for TransCanada PipeLines Limited, each seeking a licence to export natural gas, and in the matter of an application dated February 10, 1989 by ICG Utilities (Ontario) Ltd. for a licence to export and reimport natural gas, and in the matter of an application dated November 15, 1988 by ProGas Limited for a change, alteration or variation of gas export Licence Nos. GL-80 and GL-81, and in the matter of an application dated November 21, 1988 by Shell Canada Limited for a change, alteration or variation of gas export Licence No. GL-100.

In response to concerns raised by producers and other interested parties the Board decided to conduct a review of the role, if any, that benefit-cost analysis should play in the market-based procedure.

The NEB received submissions from seventy-six interested parties as to whether the benefit-cost analysis should be retained in assessing export applications. In its decision to drop benefit-cost analysis from its export licencing process, the NEB concluded that the uncertainty surrounding the results of benefit-cost analysis (i.e., the appropriate discount rates, the level and shape of gas supply curves and the basis used by producers in developing their views on gas supply costs) was too great to warrant its continued use in gas export licencing in the current deregulated and market-oriented environment. The decision to discontinue using benefit-cost analysis was confined to Part VI proceedings of the Act. Although several opponents of the benefit-cost analysis claimed that the test was a violation of the Canada-U.S. Free Trade Agreement, the NEB said its decision to drop the test was not related to the Free Trade Agreement.

In addition to deciding the fate of benefit-cost analysis the NEB also examined the issue of flexibility in export contracts to reflect changing market conditions over the life of the contract. The NEB decided that it would continue to examine contracts in support of gas export applications to ensure their commerical substance and durability. However, it would operate on the presumption that contracts freely negotiated at arm's length would be in the public as well as in the private interest and consequently the NEB would only intervene in exceptional circumstances, on the issue of flexibility of terms.

2. Competition Tribunal/Bureau of Competition Policy

(a) Decisions

(i) NR-10082 Nova Acquisition of Polysar Shares, May 5, 1988

The Director of Investigation and Research (the "Director") did not apply to the Competition Tribunal. However, his inquiry continued and it was determined that the Bureau of Competition Policy (the "Bureau") would monitor the impact on competition in the production and supply of ethylene over the statutorily imposed three year period. It was further determined that the acquisition by Nova Corporation of Alberta ("Nova") of 25% of the voting securities of Polysar Hydrocarbons Limited constituted a "significant interest" within the section 63 *Competition Act*[85] definition of "merger" (i.e., means the acquisition or establishment, direct or indirect, by one or more persons, whether by purchase or lease of shares or assets, by amalgamation or by combination or otherwise, of control over a significant interest in the whole or a part of a business of a competitor, supplier, customer or other person) and that the competitive effects of the transaction were likely to be affected by a number of considerations including long-term contracts, Alberta government policy, transportation economics, new facilities and the exercise of power by Nova. It was the view of the Director that additional information obtained through monitoring would permit a better assessment of the competitive impact at a later stage in the three year period. Of particular interest in this decision was that consideration was given to the fact that

85. R.S.C. 1985, c. C-34.

the Free Trade Agreement is expected to make the market for the products more competitive.

(ii) NR-89-11 Imperial Oil Ltd. Purchase of Texaco Canada Inc. Shares, February 24, 1989

The Director announced that the acquisition of shares of Texaco Canada Inc. ("Texaco") by Imperial Oil Ltd. ("Imperial") would not affect the ongoing examination of the transaction and that the parties were proceeding at their own risk. The Director also announced that the Bureau had competition concerns in the downstream section (includes petroleum refining, distribution and marketing). In that regard the Director suggested that a divestiture of assets would likely be required. Imperial gave its unconditional undertaking to comply and also to hold separate the downstream operations of Texaco pending the resolution of the Director's concerns. The Director found no serious competition concerns in the upstream section (includes exploration for and the production of oil and gas and pipeline transportation).

The Bureau and Imperial then reached an agreement under which Imperial would sell 543 of the 5,141 Esso and Texaco gasoline stations it owned across Canada, 14 storage and distribution terminals and Texaco's Dartmouth, N.S. refinery. Imperial also agreed to guarantee 1.5 billion litres of gasoline annually to independent service station operators in Quebec and Ontario for at least seven years. This ruling, however, still had to be approved by the Competition Tribunal and several parties filed documents before the Competition Tribunal disputing the terms of the consent order issued by the Bureau. This included the Province of Quebec which claimed that the Bureau's requirement that Imperial sell 77 retail stations in Quebec did not go far enough to ensure effective competition in the province after the merger. Imperial then agreed to sell an additional 68 gas stations in Quebec and Quebec subsequently withdrew its opposition to the proposed merger.

At the end of month-long public hearings the Competition Tribunal decided not to approve the previous agreement between the Bureau and Imperial, stating that the same did not do enough to preserve competition. Imperial then responded to the Competition Tribunal's decision by pledging to set out specific guarantees for the sale of gasoline to independent stations and to ensure that the Texaco refining and marketing network in Atlantic Canada would be sold to a single buyer with "financial clout". On February 6, 1990 Imperial received final approval from the Competition Tribunal. Certain Texaco Canada Inc. gasoline station dealers have, however, petitioned the Competition Tribunal to re-open its examination of this merger.

(b) Published Policy Statements

Historically, enforcement of the *Competition Act* and the deterrence of anticompetitive activity had focused on the investigation of violations under the Act with a view to prosecution and the imposition of criminal penalties. Now, however, in an effort to improve the effective enforcement of the Act, the Bureau is developing a voluntary compliance program in an attempt to focus on preventing violations rather than discovering and initiating legal proceedings after violations have occurred. The new compliance initiatives of the Bureau are designed to encourage parties and their counsel to discuss with the Director the details of any proposed business plan which might run afoul of the competition laws. A new compliance unit has been created in the hopes that the voluntary compliance programme can resolve problems without costly court proceedings.

The Bureau's programme of compliance is intended to be a "vigorous and sustained programme involving education, explanation, discussion of business problems, and the provision of opinions" concerning the application of the Act (through greater use of speaking engagements, publications and increased dissemination of bureau policy). This emphasis on voluntary compliance reflects several factors including:

(a) the shift away from criminal law to civil law in the Act;
(b) the stronger statutory base for negotiated settlements;
(c) the Neilson Task Force recommendation to develop a comprehensive pro-active public education programme;
(d) a pro-active compliance programme; and
(e) the increased use of negotiated settlements.

This new policy objective of increasing compliance initiatives is in accord with developments in other leading industrial nations under their respective anti-trust regimes (i.e., The United States, The United Kingdom, Japan and Australia). Pre-inquiry compliance initiatives include:

(a) advance ruling certificates;
(b) non-binding preliminary compliance opinions on a case specific or no names basis;
(c) enforcement guidelines and interpretive comments on recent jurisprudence;
(d) speaking engagements; and
(e) an improved flow of information to the public through the preparation and circulation of such items as newsletters, information pamphlets, industry guidelines and interpretation bulletins.

The Director is also considering the creation of a special advisory group to provide ongoing input on how the implementation of the Act is being perceived by the business community, the legal profession and the public at large. As noted in Information Bulletin No. 3 (June, 1989) entitled "Program of Compliance":

> The Director believes that the majority of business persons will respect the *Competition Act* if they understand how it applies to their business affairs. Therefore, he attempts to encourage general compliance with the Act through a program of communication and education. In addition, he facilitates compliance in particular situations through advisory opinions, information contacts and advance ruling certificates.

3. Investment Canada

(a) Decisions

Recommendations and reasons for decisions of the Minister responsible for the *Investment Canada Act*[86] are kept in confidence.

(b) Published Policy Statements

Investment Canada does not make policies, it simply applies policies (i.e. the Oil and Gas Acquisition Policy referenced below) determined by the Federal Government. Investment Canada then makes recommendations to the Minister, based on these policies.

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86. S.C. 1985, c. 20.

The only recent policy statement that could be located at the time of writing is contatined in a letter dated May 12, 1988 from The Honourable Michael Wilson addressed to The Honourable James A. Baker, wherein Mr. Wilson sets forth the Canadian policy respecting the acquisition by foreign investors of oil and gas businesses in Canada insofar as they may pertain to the *Investment Canada Act.* This letter serves as the most succinct articulation of the policy of the Minister responsible for Investment Canada. The policy provides that, in reviewing acquisitions, the Minister will:

(a) disallow the direct acquisition of a healthy Canadian-controlled business with assets of at least $5 million;

(b) consider allowing the direct acquisition of a Canadian-controlled business with assets of at least $5 million that is in clear financial difficulty and in such cases the Minister would review the proposed foreign acquisition to evaluate its net benefit to Canada and could negotiate, as necessary, undertakings by the acquiror in relation to the review criteria;

(c) normally allow the direct acquisition of a foreign-controlled business with assets of at least $5 million, subject to an agreement with the acquiror on conditions relating to Canadian ownership and investment spending; and

(d) normally allow the indirect acquisition of a foreign-controlled business with assets of at least $50 million, subject to an agreement with the acquiror on conditions related to Canadian ownership and investment spending.

In November, 1989 IPAC made a submission to Investment Canada with respect to current Investment Canada policy insofar as the same applies to the Canadian oil and gas industry. In its submission, IPAC stated that:

> . . . the current Investment Canada policy unnecessarily discriminates against the oil and gas industry. The policy restricts the free flow of capital into Canada at a time when it is most required to develop our oil and gas resources and thus ensure the longer term security of supply for Canadians. IPAC believes that the Investment Canada rules can be made less restrictive on oil and gas and that significant benefits will be realized from increased foreign investment.

At the time of writing we are not aware of any response having been received from Investment Canada as a result of IPAC's submission.

4. Environmental Canada

(a) Decisions

Recent decisions of the Federal Court of Canada[87] have established that the present Federal Environmental Assessment and Review Process Guidelines Order applies to any proposal that may have environmental consequences in an area of Federal responsibility. These cases have further exacerbated an already difficult Federal-Provincial jurisdictional conflict concerning responsibility for environmental review and assessment of major projects in the western provinces.

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87. *Canadian Wildlife Federation Inc.* v. *Canada (Minister of Environment)* (1990), 31 F.T.R. 1 (F.C.T.D.); *Friends of the Oldman River Society* v. *Canada (Minister of Transportation and Minister of Fisheries and Oceans)* (1990), 108 N.R. 241 (F.C.A.D.).

(b) Published Policy Statements

In a speech given in Montreal on April 26, 1990, the Minister of Energy, Mines and Resources, Jake Epp, suggested that his government had "come a long way in terms of establishing a market-oriented energy policy to the benefit of energy producers and consumers" while at the same time being cognizant of achieving "the right balance between economic and environmental considerations and how to ensure that where the inevitable trade-offs are made, they are done on the basis of a proper understanding of their nature". According to the Minister, the major challenge is the integration of environmental considerations into this market-oriented framework and progress has been made in this regard, specifically with respect to limiting sulphur dioxide emissions, formulating a management plan for nitrogen oxides and volatile organic compounds, preparedness to deal with oil spills, nuclear waste management, and identifying the nature of the problem of global warming and possible solutions.

B. ALBERTA

1. Alberta Surface Rights Board Decisions

(a) Decision 89/0001[88]

The question before the Alberta Surface Rights Board (the "Board") in this instance was whether a pattern of compensation developed by an operator on a specific pipeline system with landowners holds more weight than a pattern developed on different pipeline systems by different operators and/or landowners. The Board held that, as in the past, the strongest evidence of a pattern of compensation is the pattern on a specific pipeline system rather than a pattern developed by different operators on a different line or lines. The only exception to this rule is where the operator and land owner in their right-of-way agrement have agreed to increase compensation if the Board awards more as a result of a hearing on their specific pipeline system.

(b) Decisions 89/0004, 89/0005, 89/0006, 89/0007, 89/0008, 89/0009 and 89/0010[89]

In these decisions the Board notes that it may consider awarding costs to an operator where it is clear the actions of the respondents have been frivolous and vexatious.

(c) Decision 89/0015[90]

In this decision, like ones previous, the Board reiterates that it considers it proper to award interest on the compensation payable by the operator, but excluding special damages, from the date of the right of entry order until payment in full. Further, the Board notes that in considering costs, it is the Board's opinion that the fundamental

88. *Bankeno Resources Limited* v. *Sin Chong Chai et.al.*, January 3, 1989.

89. *Renaissance Energy Ltd.* v. *Her Majesty The Queen In Right of Alberta et.al.* January 11, 1989.

90. *North Canadian Oils Limited* v. *Albert Joseph Roy and Province of Alberta Treasury Branches*, January 24, 1989.

principle in fixing costs is that the party entitled to an award of costs is entitled to be reimbursed for any "reasonable costs reasonably incurred in and incidental to the proceedings befor the Board and necessary to the determination of fair compensation payable for that which gave rise to the proceedings".[91]

(d) Decisions 89/0017, 89/0018[92]

In this instance the operator applied to the Board for a substantial reduction in the previously established compensation for certain well sites on the basis that the subject sites are no longer being used. The Board determined that as the operator had not yet received a reclamation certificate and as such continued to have full use and control and exclusive rights to the areas granted by the original right of entry orders, the operator was obliged to pay for the exclusive use and rights on the subject lands. Accordingly, as there had been no reduction of rights, the Board was satisfied that nothing had changed in regard to the rights of entry and found no reason to adjust the compensation.

(e) Decision 89/0019[93]

This decision involved an application by a lessor to have the Board direct payment by the Provincial Treasurer of rent due on a surface lease under section 398 of the *Surface Rights Act*[94]. In refusing to so direct the Board noted that the leased area had not been used by the operator for some time and that the lessor had used part of the leased area for his farming operations. Accordingly, the Board determined that the evidence did not justify a recommendation to the Provincial Treasurer for payment of lease arrears.

(f) Decision 89/0022[95]

In this decision the Board expressly recognized that in determining compensation based on market value, the value of any reversionary interest should be deducted from the same. However, the Board also recognized that the landowner is entitled to payment for nuisance and inconvenience and, in this instance, offset the "incalculable reversionary"[96] interest against compensation for nuisance and inconvenience.

(g) Decision 89/0031[97]

The parcel of land in question here was 3.02 acres. The Board determined that section 25(1)(a) of the *Surface Rights Act* did not apply and was not an appropriate means of valuing the land as there was no persuasive evidence that it was a saleable

91. *Ibid.*, at 5.

92. *Inverness Petroleum Ltd.* v. *Cornelius A. Van Hal et.al.*, January 24, 1989.

93. *Cornelius A. Van Hal* v. *Inverness Petroleum Ltd.*, January 24, 1989.

94. R.S.A. 1980, c. S-27.1.

95. *Alberta Power Limited* v. *Clarence Herbert Coulthard et.al.*, February 3, 1989.

96. *Ibid.*, at 7.

97. *Intensity Resources Ltd.* v. *E. Tatem Holdings Ltd.*, February 27, 1989.

parcel which could justify considering "the amount the land granted might be expected to realize if sold" in isolation from consideration of other factors.

(h) Decision 89/0037[98]

As was the case in numerous previous decisions, the Board reiterated that any loss of the productive use of the demised premises should reflect the returns reasonably expected from that area over the short term, with consideration given to any saving of direct input costs resulting from the exclusion of that area from the existing farm operation.

(i) Decision 89/0069[99]

In this case the operator argued that the offered compensation, which was rejected by the land owner, was predicated on the operator getting immediate entry by surface lease rather than the right of entry process and, accordingly, represented inflated values. The operator took the position that such an offer should accordingly be disregarded by the Board in establishing compensation. The Board did not accept the argument that because the landowner chose to go by way of right of entry, rather than a negotiated agreement, that he was entitled only to a lesser amount of compensation.

(i) Decision 89/0117[100]

In this decision the Board dealt with the argument by the respondent, a lessee under a Crown grazing lease, that there is no reason for the disparity between what is paid by operators on deeded land as compared to leased land. The respondent contended that, based on the fact that the productivity of the leased land is equal to that of deeded land, there should be no differentiation in terms of compensation. The Board noted, however, that its previous rulings - that legally the lessee is entitled to be compensated only for the damages caused to its rights that are inherent in its lease agreement - had been upheld by the courts (i.e., the Crown is the owner and is entitled to all other compensation) and that, unlike deeded lands, there are two claimants for compensation, the Crown as owner and the lessee. The Board also stated that if this results in a different amount of compensation than an individual owning and occupying the land, this is because of the claimants and not the operator.

(k) Decision 89/0155[101]

In this matter, and having particular regard to the fact of the indefinite term of the right-of-entry order as of the date of the right of entry (i.e., the rights granted by right-of-entry orders are virtually rights in perpetuity, rights which traditionally can only be acquired by up-front payment of value or by a long term lease subject to

98. *Arthur Schatz* v. *Coseka Resources Limited*, March 3, 1989.
99. *Renaissance Energy Ltd.* v. *Florence Allison Fawcett and Donald C. Fawcett*, April 24, 1989.
100. *Opinac Exploration Limited* v. *Her Majesty The Queen In Right of Alberta et.al.*, July 7, 1989.
101. *Dekalb Energy Canada Ltd.* v. *Frank J. Bonetti and Carol Bonetti*, August 30, 1989.

periodic contract payments to maintain that right of occupancy), the Board was of the opinion that the disturbance and damage to the surface rights of the landowner resulting from the exercise of the right-of-entry was to the full extent of the value to the owner of the land acquired by the operator.

(l) Decision 89/0156[102]

Again in connection with a lessee of Crown lands, the Board had to consider whether the pattern of compensation of $2,000 for the first year and $1,000 annually should apply regardless of the fact that the lease site in this instance was two to three times the normal size. The Board concluded that in fact an adjustment to the standard pattern was warranted. However, at the same time, the Board agreed with the operator that general and adverse effect is not doubled by doubling the size of the area.

(m) Decision 89/0173[103]

In this instance a well was drilled and resulted in a dry hole. The well was subsequently abandoned and the lessor entered into a verbal agreement with the operator to do further work and seed the site. However, as a result of wet weather the lessor was unable to seed the area and consequently refused to accept the site. The operator on the other hand contended that as the lessor verbally agreed to do the seeding its obligations were complete and it should not be required to pay the 1988 rental. The Board determined that it was not empowered to deal with the issue of the legalities of the verbal understanding and as no reclamation certificate had been issued by the Land Conservation and Reclamation Council ("LCRC"), the lease had not been properly surrendered and was therefore still in effect.

(n) Decision 89/0176[104]

In this decision the Board followed precedent in holding that only a nominal payment is due the landowner on the construction of a second pipeline on an existing pipeline right-of-way.

(o) Decisions 89/0199, 89/0200, 89/0201, 89/0202, 89/0203, 89/0204, 89/0205, 89/0206, 89/0207, 89/0208, 89/0209, 89/0210[105]

In determining the loss of use and adverse effect of nine well sites the Board concluded in this instance that rather than being considered as separate sites, due to the interrelationship of the adverse effect, all nine well sites should be judged as a total entity.

(p) Decision 89/0221[106]

In this decision the Board stated that although, at best, adverse effect is a judgment call, adverse effect includes the inconvenience and added cost to normal field operations in the vicinity of the demised premises, extra operating time resulting from field

102. *Roan Resources Ltd.* v. *Her Majesty The Queen In Right of Alberta et.al.*, August 31, 1989.

103. *Julian Lyle Prenioslo* v. *362107 Alberta Inc.*, September 28, 1989.

104. *Gulf Canada Resources Ltd.* v. *Bryan Gist et.al.*, October 11, 1989.

105. *John Albert Ferris* v. *Mobil Oil Canada*, December 13, 1989.

106. *Dennis E.A. Broen* v. *Esso Resources Canada Limited*, December 28, 1989.

obstruction, extra care and attention required in all field operations in the vicinity of the obstruction, yield losses which may result from overlap or misses, extra turning and combined losses due to the obstruction and any problems likely to arise from unattended weed infestations encroaching off the demised premises into the adjoining land.

(q) Decisions 89/0197, 89/0198[107]

In this decision the Board stated that the factors of nuisance, inconvenience and noise will obviously be greater in the first year than in subsequent years due to the more varied activity at the outset of operations. In the first year this will involve the initial dealings with the operators personnel, adjusting to the intrusion on the private enjoyment of the subject land, the "hectic" activities normally associated with such operations, increased traffic into the lands and monitoring the operations so as to ensure property interests are properly respected. The Board concluded that in subsequent years the main effects would be the possible need for increased surveillance of the real and personal property, concerns over safety and security and easier access onto the land by unauthorized persons.

(r) Decision 89/0075[108]

In this case a dry hole was drilled. Counsel for the operator argued that in assessing compensation the Board should consider those facts at the time of the hearing rather than the facts that existed at the time of negotiation. In that regard it was argued that if the fee value of the land is to be awarded there should be a reversionary value deducted and additionally, there should be no award for loss of use. The Board in a relatively lengthy decision did not accept the foregoing argument, noting that it did not concur that the intent of the *Surface Rights Act* was to have the landowner gamble on the odds of a producing well versus a dry hole because of being forced to proceed by way of right-of-entry due to his refusal of the operator's offer.

2. Energy Resources Conservation Board ("ERCB")

(a) Decisions

(i) Decision D89-3

Benza Oil & Gas Ltd. ("Bonanza") applied for a well licence to drill a well located at Lsd. 16-9-34-1 W4M in the Altario field. The interesting issue arising from this application was the opposition to the application that arose because the proposed well would be located on native prairie Crown land that is administered by the Special Areas Board of the Alberta Department of Municipal Affairs.

The intervenors opposing Bonanza's application held a Crown grazing lease over the lands that would be the site of the proposed well. Bonanza contended that the issues raised by the intervenors "were beyond their legal and proprietary interest in

107. *Gannon Bros. Energy Ltd.* v. *Bernard John Van Straten et.al.*, December 13, 1989.

108. *Tintagel Energy Corporation* v. *Lawrence Clarkson Walton et.al.*, May 10, 1989.

the land as grazing lessees'' and that the preservation issues raised were improperly placed before the ERCB. Bonanza also claimed that its right of access to the proposed site and any reclamation issues were in the domain of the Special Areas Board and the LCRC and not within the purview of the ERCB. The ERCB dismissed both of Bonanza's arguments on the basis that any rights that impact on the rights held by the intervenor as a licencee must be considered. In addition, the ERCB pointed out that pursuant to section 2 of the *Energy Resources Conservation Act,*[109] the ERCB is empowered to ensure environmental conservation in the development of energy resources and that it was proper to consider the impact the proposed well would have on native prairie habitat. While recognizing that the Special Areas Board and the LCRC have discretion in ensuring that land surface is protected, the ERCB was of the opinion that neither of these groups had exclusive jurisdiction over the matter. Consequently, the ERCB found that it has jurisdiction to issue conditions on a well licence that would mitigate any impacts on land surface.

The ERCB heard evidence from the intervenors and several witnesses for the intervenors regarding the need to protect native prairie habitat. Bonanza did not present or question evidence presented with respect to the need for protecting such lands. However, Bonanza expressed concern that its application for a well licence should not be used to formulate a policy to govern all oil and gas operations that may impact native prairie.

In its decision granting Bonanza's application the ERCB recognized the importance of preserving native prairie and agreed with several of the intervenor's witnesses that ''discipline, good management, and flexible guidelines can be utilized to reduce the impact of oil and gas development activity on native prairie''.[110] The approval given to Bonanza was subject to conditions that had the effect of requiring Bonanza to take into account the preservation of native prairie and among other things instructed Bonanza to retain a specialist in native grasslands ecology to oversee Bonanza's development of the lands upon which its well would be located.

(ii) Decision 89-7

The significance of this hearing and the decision that followed was the consideration given to the issue of gas plant proliferation in Alberta. As indicated in this decision the ERCB's policy is to discourage the proliferation of gas plants and to utilize existing plant capacity where possible.

This hearing arose pursuant to an application made by Unocal under section 26 of the *Oil and Gas Conservation Act*[111] for approval to construct and operate a sweet gas processing plant to be located in the Albright field in northern Alberta. Unocal indicated that its decision to construct and operate a new gas plant was made after it had investigated the feasibility of utilizing four existing plants and concluded, for a variety of reasons, that there was no viable processing alternative available. Unocal argued that the issue of gas plant proliferation, therefore, did not arise. It was Unocal's position that existing facilities should not be utilized at all costs, but only where it is

109. *Supra*, note 60.

110. Energy Resources Conservation Board Decision D 89-3 dated July 4, 1989 in the Matter of an Application for a Well Licence by Bonanza Oil & Gas Ltd., at 7.

111. *Supra*, note 56.

economic, orderly and efficient to do so and that the economics of using an existing gas plant would have to at least equal that of a new plant.

Intervenors at the hearing disagreed with Unocal's position and were of the opinion that existing plants should be utilized "even if they were a little more costly to do so".[112] The intervenors contended that consideration must be given to the social implications of any energy development and economics should not be the deciding factor.

In its decision the ERCB reiterated its policy to discourage the proliferation of gas plant facilities. However, the ERCB indicated that such discouragement should not be at all costs. The ERCB stated that two of the more important considerations when deciding on new gas plants are economic factors and the existence of possible alternatives. Unocal's application was denied by the ERCB on the basis that a new gas plant was economically advantageous only if plant throughput was to be significantly increased and this was not exhibited in Unocal's application. Thus, further consideration of utilizing existing gas plant facilities was warranted. In the result, the ERCB was not convinced that Unocal had demonstrated that a new gas plant was required.

(b) Published Policy Statements

(i) Information Letter 89-22

In Information Letter IL 89-22 dated December 21, 1989 the ERCB announced that it planned to develop measures aimed at curbing the number of orphan wells (i.e. wells that have been deserted by their owners) in Alberta. The abandonment of a well is governed by the *Oil and Gas Conservation Act* and its Regulations. There is no statutory obligation contained in the Act or the Regulations requiring an operator to abandon a well. Pursuant to section 10(1) of the Act, the ERCB may make regulations requiring notice to the ERCB of intention and seeking the approval of the ERCB before a well is abandoned. The only legislative requirement regarding how to abandon a well is found in Regulation 3.07, which stipulates that when a well is being abandoned, the licensee shall plug the well in a certain manner.

The measures contemplated by the ERCB to minimize the number of orphan wells include taking a firmer position on the transfer of well licences. Specifically the ERCB, before consenting to a transfer of a well licence where the transferee does not have a proven operating record in Alberta, shall require the transferee to provide the ERCB with documentation regarding its ability to carry out all of the responsibilities it will assume as the holder of a well licence. If the transferee is unable to satisfy the ERCB as to its ability to carry out the responsibilities of a licensee the ERCB will deny the transfer, even if a sale transaction has been completed.

In addition to the ERCB's stronger position on well licence transfers, proposed legislative changes to the *Oil and Gas Conservation Act*, the *Energy Resources Conservation Act*, and the *Mines and Minerals Act*,[113] address several weaknesses in the legislation regarding the timing for the abandonment of wells and the obligation to abandon a well site in accordance with the Regulations.

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112. Energy Resources Conservation Decision D 89-7 dated August 15, 1989 in the Matter of an Application for Approval of a Sweet Gas Processing Plant, at 5.

113. See page 14.

(ii) Information Letter IL 89-4

In June, 1989, the ERCB and Alberta Environment ("AE") issued guidelines in Information Letter 89-4 regarding the public involvement of Albertans in energy developments. Although these guidelines are not fixed in regulation, they represent the "kinds of things that ERCB and AE urge companies to consider when they are submitting energy applications for evaluation".[114] Two of the objectives the ERCB and AE are striving to achieve through the publication of Information Letter 89-4, are to "foster a more thorough understanding, by everyone concerned, of the needs and concerns of all those involved in energy developments" and "to ensure that public involvement occurs in such a manner and time that people's concerns may be properly addressed and resolved".[115]

In addition, the ERCB and AE outline actions that the public can take to make the energy development process more efficient and effective. To this end the ERCB and AE encourage Albertans, among other things, to learn more about the business of resource development and to bring their concerns regarding potential developments to the attention of the company involved as early as possible, in an effort to resolve outstanding issues without he intervention of third parties. For their part, the ERCB and AE also propose to conduct a variety of programs to facilitate the interaction and communication between the energy industry and the public to help ensure that public concerns can be addressed as early as possible in the over-all process and thus reduce the time and cost of formal hearings.

3. Alberta Public Utilities Board ("PUB") Decisions

Over the period May, 1989 through April, 1990 the Alberta PUB released two decisions which provide insight into matters that may be of some interest and significance to oil and gas lawyers.

(a) Decision E90023 dated March 2, 1990

The issue of interest in this decision was whether the PUB should preserve "the blanket of confidentiality that surrounds certain evidence and information responses provided to the Board".[116] The PUB heard submissions from interested parties that the evidence they presented to the PUB should remain confidential for several reasons, including that "an element of confidentiality must exist to protect each company's competitive interest".[117] The PUB did not accept these arguments. It decided

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114. Energy Resources Conservation Board Informational Letter IL 89-4 dated June 22, 1989 in Respect of Public Involvement in the Development of Energy Resources, at 1.

115. *Ibid.*, at 2.

116. Public Utilities Board (Alberta), Decision E90023 dated March 2, 1990 In the Matter of an Application for Increases in the Minimum Wholesale and Minimum Retail Prices of Fluid Milk and Other Fluid Milk Products by Palm Dairies Limited, Alpha Milk Company (a Division of Central Alberta Dairy Pool) and Northern Alberta Dairy Pool Limited for the test years 1989 and 1990, at 4.

117. *Ibid.*

that the same standards of natural justice must be adhered to in all proceedings before the PUB and that "all parties who may be adversely affected by the increase or any adjustment to the existing price schedules should be afforded the opportunity to examine the evidence presented in support of the application or evidence otherwise relied upon by the Board in its written decision on the merits of the case".[118] This finding reiterates an earlier decision of the PUB dealing with a claim for confidentiality respecting particulars of certain coal contracts wherein it was stated:[119]

> Access to all relevant information is a vital component of the fair hearing process. When participants are denied access to information, they may be deprived of their right to fully participate in the Board's hearing process.

(b) Decision E89004 dated February 15, 1989

The second decision of the PUB addressed a jurisdictional issue having widespread applicability. Simply stated, the central issue was whether the PUB, when determining upstream costs, can exercise its jurisdiction pursuant to section 82 of the *Public Utilities Board Act*[120] to determine whether an asset is "used or required to be used" to provide service to the public within Alberta. The argument put forward to exclude the PUB from having jurisdiction in this matter was that once an electrical utility received approval from the ERCB to construct an electrical plant, the PUB cannot make a "used or required to be used" finding with respect to the plant and must accept the costs so filed. The PUB decided that while the ERCB has the authority to approve the construction and operation of a power plant, the PUB's mandate to set "just and reasonable rates is a distinct function from that of the ERCB's power to approve construction of a facility" and the PUB's duties under the *Public Utilities Board Act*, including its "used or required to be used" test, "does not, in any way, encroach upon the ERCB's decisions respecting construction of a plant or commissioning or operating dates". The decision of the PUB in imposing the section 82 test was upheld by the Alberta Court of Appeal in its decision dated February 14, 1990.[121] The parties adversely affected by the Court of Appeals's ruling are presently requesting leave to appeal to the Supreme Court of Canada.

C. ONTARIO

1. Ontario Energy Board ("OEB") Decisions

(a) Decision E.B.R.L.G. 33 dated December 21, 1989

In April, 1989, ICG Utilities (Ontario) Ltd. ("ICG Ontario") applied to the OEB for, *inter alia*, exemptions to undertakings (the "Undertakings") given to the Lieutenant Governor in Council for the Province of Ontario in June, 1988. Articles 5.4(a) and (b) of the Undertakings forbid ICG Ontario from investing in a non-utility, non-

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118. *Ibid.*, at 11.

119. Public Utilities Board (Alberta) Decision E87025 dated April 2, 1987 in the Matter of an Application made by Alberta Power Limited for an Increase in Rates.

120. *Supra*, note 52.

121. *Alberta Power Limited, TransAlta Utilities Corporation and the City of Edmonton* v. *The Alberta Public Utilities Board*, [1990] 10 A.W.L.D. 8, 9 March 1990 (Alta. C.A.).

regulated activity and provides that ICG Ontario will attempt to restructure itself so that its activities shall relate only to the regulated natural gas distribution business in Ontario.

ICG Ontario proposed to invest in a cogeneration project to be built at the site of a pulp and paper mill operated by Boise Cascade Canada Ltd. ("Boise") near Fort Frances, Ontario. The project was proposed to be owned by ICG Ontario and held as a division of the company. The proposed cogeneration project was a significant non-utility investment and required exemption from the Undertakings. The OEB's decision regarding the applied-for exemptions is interesting because the OEB saw itself having to weigh government policy favouring cogeneration against the government's concern about diversification and non-utility investment by regulated utilities in Ontario and the risks that this could pose for utility operations and gas consumers.

In its written decision the OEB indicated that if the cogeneration project had been reviewed by the OEB prior to any funds being expended or committed, the OEB would have denied ICG Ontario's application for an exemption to the Undertakings. However, because considerable sums of money were spent and commitments entered into before the OEB could have responded to ICG Ontario's application and by virtue of the government's public statements approving of ICG Ontario's cogeneration project, the OEB recommended that dispensation be granted to ICG Ontario in respect of the Undertakings. It is noteworthy that the OEB, because of government statements approving of the project, felt that its role as agent of the Lieutenant Governor in Council was "severely, if not entirely constrained in this case".[122]

In determining whether ICG Ontario's rate base should include the costs associated with the cogeneration project, the OEB's primary concerns were with the protection of the utility function of ICG Ontario and utility customers in Ontario from any risk associated with the project and any potential benefit to utility ratepayers.

The OEB concluded that, in the absence of a legal separation of the project from the utility operations of ICG Ontario, the Lieutenant Governor in Council should deny the request of ICG Ontario for special accounting treatment and direct ICG Ontario to continue to operate under the jurisdiction of the OEB regarding the amounts to be excluded from utility rate base, utility income, and taxes applicable on account of the cogeneration project. The OEB reasoned that "it would be an unprecedented departure from the principles of regulation to allow ICG Ontario to determine the amounts to be excluded from rate base, utility income, and the amount of taxes payable by the cogeneration project if it were to remain a division of ICG Ontario".[123]

(b) Decision E.B.R.L.G. 34 dated August 25, 1989

Pursuant to an application dated August 25, 1989 filed with the OEB, Inter-City Gas Corporation ("Inter-City") requested leave for a proposed change in control of ICG Utilities (Canada) Ltd. ("ICG Canada") to be carried out pursuant to a Letter of Understanding dated July 4, 1989 between Inter-City and Westcoast Energy Inc. ("Westcoast").

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122. Ontario Energy Board E.B.R.L.G. 33 dated December 21, 1989 in the Matter of a Reference to the Ontario Energy Board by the Lieutenant Governor in Council under Section 36 of the *Ontario Energy Board Act*, in respect of a proposal by ICG Utilities (Ontario) Ltd. to conduct a Cogeneration Facility, at 77.

123. *Ibid.*, at 95.

In June, 1988, Inter-City, ICG Canada and ICG Ontario gave certain undertakings (the "Undertakings") to the Lieutenant Governor in Council of the Province of Ontario. Included among the Undertakings were provisions that prohibited a change of control of ICG Ontario without first obtaining leave of the Lieutenant Governor in Council. The transactions contemplated in the Letter of Understanding were covered by the Undertakings since the contemplated acquisition of Inter-City's utility business by Westcoast would involve a change in control of ICG Canada and ICG Canada owned all the outstanding voting shares of ICG Ontario.

In examining the proposed change of control from Inter-City to Westcoast the OEB focused on whether such a change was in the public interest. In considering matters of public interest the OEB focused on areas of corporate finance and operating policies that could affect the interest of stakeholders in the Ontario utility business of ICG Ontario and considered whether a change of control was desirable. In its examination the OEB considered the financial strength of Westcoast compared to Inter-City, the financing of the proposed transaction by Westcoast and the financial and business plans of Westcoast for its utility businesses. The OEB findings were that Westcoast was a "stronger company financially than Inter-City and has the capacity to acquire the utility business of Inter-City without materially changing Westcoast's ability to raise capital in the future"[124] and that the proposed change of control was in the public interest.

The significance of this decision is the way in which the OEB approached the proposed change of control. The OEB's financial examination was thorough and rigorous in assessing whether Westcoast should be permitted to take over Inter-City's utility operations and resulted in rigid conditions imposed on Westcoast in allowing it to proceed with the transaction.

(c) Decision E.B.L.O. 234 dated March 1, 1990

Pursuant to an application dated July 24, 1989 Union Gas Limited ("Union") applied to the OEB for an order granting leave to construct a pipeline and additional compression and measurement facilities that would form part of Union's Dawn-Trafalgar System which transports natural gas between Union's Dawn Compressor Station as its west end near Sarnia, Ontario and its Trafalgar Compressor Station in Oakville, Ontario at its east end. CNG Transmission Corporation and the Consumers' Gas Company Limited submitted that Union had not presented evidence to support the need for the construction of the applied for facilities in 1990 and that approval of the facilities should not be granted until contracts establishing need had been filed with the OEB. Union was of the view that an explicit demonstration of need was not a requirement under the *Ontario Energy Board Act*,[125] maintaining that section 46 of the Act specifies public interest as the only criterion to be met. The OEB found that with the filing of certain letter agreements, Union had discharged its onus to present firm commitments to establish the need required for construction of the

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124. Ontario Energy Board E.B.R.L.G. 34 dated January 31, 1990 in the Matter of an Application dated August 25, 1989 for leave of the Lieutenant Governor in Council with Respect to the Proposed Change in Control of ICG Utilities (Canada) Ltd., at 69.

125. R.S.O. 1980, c. 332.

pipeline. As regards future applications by Union to address future needs, the OEB cautioned Union that "unless a convincing argument can be made for approving facilities in anticipation of future need, such applications seeking approval should be accompanied by contractual commitments to substantiate need and the ability to recover costs".[126]

An interesting aspect of the OEB's decision is the finding that Union's current procedure for communicating with landowners during construction of the pipeline should be improved. As a result of this finding the OEB directed Union to "establish a procedure whereby landowners can be reasonably guaranteed rapid acccess to a senior manager at times when they feel a field representative has made an inappropriate decision" and "to maintain a written log of all landowner complaints".[127]

(d) Decision E.B.R.O. 462 dated April 9, 1990

Union, by application dated August 3, 1989, applied to the OEB for an order approving or fixing rates for the sale of gas and for the storage and transmission of gas. This decision is of interest primarily because of the discussion regarding the concepts of incremental tolling and a proposed generic hearing to consider various issues arising out of the current proceedings, namely; interruptibility, sustainable development and least cost planning ("LCP").

Incremental tolling is "the concept of identifying facility expenditures for new and distinct markets not traditionally served by Union for the purpose of recovering associated costs from these markets".[128] The OEB made no finding on incremental tolling at this review. However, the OEB did indicate that this matter was of such significance that it would be reviewed at Union's next main rates case.

After hearing evidence from Union, OEB staff and Energy Probe, the OEB decided that it would be appropriate to hold a generic hearing into the impact that interruptible customers have on Union's system planning and operations, sustainable development and LCP. Leaving aside the first matters, the OEB staff suggested that to meet the objectives of sustainable development, providing customers with service at the least possible cost and ensuring a fair return for the shareholder, the Board must consider the concepts underlying LCP. LCP involves managing demand rather than building to meet demand. OEB staff pointed out that demand management options have not received the attention they deserve within Union and pointed to Union's expansion activities for both out-of-franchise and in-franchise customers by way of example. The OEB, in proposing that a generic hearing be held, found that managing demand in the context of utility expansion was of interest to the OEB and that LCP must include the environmental aspects raised by Energy Probe such as minimizing the emission of natural gas into the atmosphere to combat global warming.

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126. Ontario Energy Board E.B.L.O. 234 dated March 1, 1990 in the Matter of an Application by Union Gas Limited for Leave to Construct a Natural Gas Pipeline and Ancillary Facilities, at 28.

127. *Ibid.*, at 38.

128. Ontario Energy Board E.B.R.O. 462 dated April 9, 1990 in the Matter of an Application by Union Gas Limited to the Ontario Board under Section 19 of the *Ontario Energy Board Act* for an Order Approving or Filing Just and Reasonable Rates, at 66.

III. EVOLVING REGULATORY MATTERS

A. ENVIRONMENTAL SCREENING

For the first time in the lengthy history of hearing and deciding gas export applications, the NEB began conducting environmental screening or initial assessments of such applications in March, 1990. These assessments are being conducted pursuant to the provisions of the federal Environmental Assessment and Review Process Guidelines Order (the "EARP Order").

This new and startling development was prompted by an inquiry from the Canadian Environmental Law Association ("CELA") with respect to how the Government of Canada intended to ensure compliance with the EARP Order in the case of natural gas exports from the MacKenzie Delta which had recently been authorized by the NEB in its decision GH-10-88.

Environmental screening information is now being requested routinely from all export applicants. It remains to be seen how the NEB will determine these initial assessments, whether any full scale environmental reviews will be required and how this process will be affected by forthcoming federal environmental legislation.

B. TCPL TOLL DESIGN

The single most significant issue emerging from the current proceedings under NEB Order GH-5-89 to expand the TCPL system, is how tolls will be designed for the expansion. Ever since the TCPL line was originally built, all expansions and extensions have been tolled on a rolled-in-basis, resulting in equal tolls for all shippers. Because of the massive costs of TCPL's proposed expansion, $2.6 billion, and the fact that most of the capacity will be taken up by export sales, significant pressure is coming from domestic toll payers to design tolls for the expansion on an "incremental" or "user pay" basis. This would result in higher tolls for exporters compared to domestic shippers.

The adoption of incremental tolling by the NEB would represent a significant development in the oil and gas industry. It would be particularly interesting to see what effect its adoption would have on existing contracts and proposed projects, including the expansion program planned by TCPL and the proposed $580 million U.S. Iroquois Gas Transmission System which is intended to interconnect with the expanded TCPL system at Iroquois, Ontario and provide the transportation link for Canadian gas to new markets in the U.S. northeast.

While the rolled-in versus incremental debate is not new, the Board has indicated in the GH-5-89 proceeding that, on this occasion, it will give consideration to a generic toll order which would apply both to the current and future TCPL expansions. This would be a new approach which could serve to shorten similar hearings in the future and provide greater certainty for prospective new shippers as to the economics of transporting gas on the TCPL system.

C. PREDATORY PRICING

The April 18, 1990 draft "Predatory Pricing Bulletin" has now been widely circulated for comment by the Director of Investigation and Research. Although a discussion on how allegations of predatory pricing will be examined by the Director may be of marginal interest to most oil and gas practitioners, we do not preclude the possibility that some aspect of the industry may now or sometime in the future be vulnerable to predatory pricing and accordingly we propose to give passing reference to this matter.

The draft bulletin provides guidance on the Director's enforcement policy regarding the predatory pricing provisions of the *Competition Act*. As noted in the bulletin:

> In general terms, predatory pricing is the sale of products at prices so low as to cause injury to competition through the elimination of a competitor or the deterrence of entry or expansion of competitors.

It should be noted that the premise of the Bureau's enforcement policy is that predatory pricing is considered to present a serious threat to the competitive process only in those situations in which the alleged "predator" has a reasonable expectation of recouping any foregone profits or incurred losses that result from selling at low prices. The Bureau is of the view that the initial benefits enjoyed by the consumer from low prices are outweighed by the losses incurred from higher prices and the reduced competition that will occur in the future.

The draft bulletin discusses an approach to predatory pricing that appears to be consistent with the judicial treatment of the predatory pricing provisions of the *Competition Act*. In *R. v. Hoffman-La Roche Ltd.*[129] and *R. v. Consumers Glass Co. Ltd.*[130] the Courts, in essence, established that no single factor would determine the issue of whether or not predatory pricing was occurring. Rather, a broad approach would be taken in any examination of pricing behaviour. Within the draft bulletin, the Bureau has adopted a two-stage approach to guide the examination of alleged predatory pricing situations.

The "stage one analysis" assesses the power, through unilateral conduct, to restrict ouput and raise prices in the relevant market and further assesses the entry/exit conditions (i.e., when effective entry and exit are easy, the initial low pricing behaviour of a party possessing short-run market power will not be viewed as representing a threat to competition). The "stage two analysis" then proceeds to an examination of price-cost relationships. In that regard, and as noted in the bulletin, whether a particular level of prices is regarded as predatory will depend on factors such as the duration of the period in which the low prices are maintained, whether they are adopted unilaterally or in response to pricing policies of competing parties and the underlying intent.

The foregoing is but a very brief description of the future focus of the Bureau's enforcement policy regarding predatory pricing. The draft bulletin deals with the "two-stage approach" in far greater detail and also contains illustrative cases which further serve to provide a better understanding of when and why the Bureau may take enforcement actions.

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129. (1980), 109 D.L.R. (3d) 5.

130. (1981), 124 D.L.R. (3d) 274.