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

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This article provides a brief review of recent legislative, regulatory and environmental developments of particular interest to oil and gas lawyers. Part Two of the article highlights specific legislative developments, including those affecting environmental regulation. Emphasis is placed on recent federal and Alberta legislative developments along with some noteworthy developments in British Columbia. Part Three considers regulatory developments in the context of recent tribunal decisions at both the federal and provincial levels. Federally, the article examines recent decisions by the National Energy Board. At the provincial level, decisions by the Alberta Energy Resources Conservation Board and the Alberta Public Utilities Board (now combined to form the Alberta Energy and Utilities Board) are considered.

TABLE OF CONTENTS

I. INTRODUCTION ... 738
II. LEGISLATIVE DEVELOPMENTS ... 739
A. FEDERAL LEGISLATION ... 739
B. ALBERTA LEGISLATION ... 744
C. BRITISH COLUMBIA LEGISLATION ... 749
III. REGULATORY DEVELOPMENTS ... 753
A. FEDERAL ... 753
B. ALBERTA ... 766

I. INTRODUCTION

In this article we have departed somewhat from the broader review employed for this topic in previous years. This year we have chosen to focus on, and describe in more detail, some of the developments we believe to be most significant. The review of environmental developments is also an integral part of our discussion concerning legislative and regulatory developments. As well, we have described in some detail the procedures under the new federal and British Columbia environmental assessment statutes, since both of these Acts will affect certain oil and gas project developments.

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II. LEGISLATIVE DEVELOPMENTS

A. FEDERAL LEGISLATION

1. Statutes

a. *Canadian Environmental Assessment Act*[1]

(i) Background

The *CEAA* came into force on January 19, 1995. The *CEAA* imposes broad duties and obligations on federal authorities to conduct environmental assessments of certain projects. The *CEAA* replaces the *Environmental Assessment and Review Process Guidelines Order*[2] that had become the basis for federal environmental assessments. In addition, four regulations were made which affect the scope of assessment under the *CEAA*.[3]

(ii) Purposes of the *CEAA*

The purposes of the *CEAA* are to ensure that environmental effects are considered prior to implementation of projects, to promote sustainable development, to ensure that applicable projects do not cause environmental damage to lands outside the jurisdiction of the *CEAA* and to promote public participation in the environmental assessment process.

(iii) Application of the *CEAA*

The undertaking of a "project" as defined by the *CEAA* determines when an environmental assessment is to be conducted. A project includes the construction, operation, modification, decommissioning and abandonment of a physical work that is not excluded under the *Exclusion List Regulations* and any proposed physical activities not relating to a physical work that are included under the *Inclusion List Regulations*. Under s. 5 of the *CEAA*, an environmental assessment is required where a federal authority is the proponent of or is committed to a project, participates in financial arrangements to a project proponent, has the administration of federal lands committed to a project, or issues certain regulatory approvals set out in the *Law List Regulations*. Projects identified in the *Exclusion List Regulations* may not require an environmental assessment.

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[1] S.C. 1992, c. 37 [hereinafter *CEAA*].

[2] SOR/84-467 [hereinafter *EARP Order*].

[3] *Law List Regulations*, SOR/94-636; *Inclusion List Regulations*, SOR/94-637; *Comprehensive Study List Regulations*, SOR/94-638; and *Exclusion List Regulations*, SOR/94-639.

(iv) Energy Projects Requiring Assessment

Regulatory approvals under the jurisdiction of the National Energy Board for which an environmental assessment will be required include the construction and relocation of interprovincial and international pipelines, the construction, relocation and abandonment of international and interprovincial power lines, and approvals relating to various utility crossings needed for pipeline construction. Energy project activities which require regulatory approvals under certain other Acts or regulations may also trigger environmental assessment. Oil and gas export authorizations are not included in the *Law List Regulations* and therefore are not subject to mandatory environmental assessment under the *CEAA*.

Energy projects which require a comprehensive study include: electricity generating plants with a capacity of 200 megawatts or more; electrical transmission lines with a voltage of 345 kilovolts or more and that are seventy-five kilometres or more in length on new rights-of-way; offshore oil and gas production facilities; heavy oil or oil sands processing facilities with an oil production capacity of more than 10,000 cubic metres per day; oil refineries and heavy oil upgraders with an input capacity of more than 10,000 cubic metres per day; sour gas processing facilities with a sulphur inlet capacity of more than 3,000 tonnes per day; various hydrocarbon storage facilities; oil and gas pipelines of more than seventy-five kilometres in length on new rights-of-way; offshore oil and gas pipelines; and various types of projects in wildlife areas or migratory bird sanctuaries.

(v) Stages of the Environmental Assessment Process

Dependent upon the circumstances, the environmental assessment process can potentially consist of four stages: screening of the project; conduct of a comprehensive study; referral to a mediator for the environmental assessment; or referral to a review panel for the environmental assessment.

(vi) Screening

Where a project is not described in the *Comprehensive Study List Regulations* or the *Exclusion List Regulations*, the responsible authority must ensure that a screening of the project is conducted and a screening report is prepared. The responsible authority can exercise its discretion to decide whether public participation in the screening is appropriate in the circumstances. After taking into consideration the screening report, public comments, if any, and the anticipated effect of mitigation measures considered appropriate, the responsible authority must take one of several prescribed courses of action. Where a project is not likely to cause significant adverse environmental effects, the responsible authority can permit the project to be carried out. Where a project is likely to cause significant adverse environmental effects that cannot be justified in the circumstances, the project cannot be carried out. Where it is uncertain whether a project is likely to cause significant adverse environmental effects, where significant adverse environmental effects are likely to occur but the project may be justified in the circumstances or where public concerns warrant a reference to a mediator or review

panel, the responsible authority shall refer the project to the Minister for a referral to either a mediator or a review panel.

(vii) Comprehensive Study Process

Where a project is described in the *Comprehensive Study List Regulations*, the responsible authority is required to ensure that a comprehensive study is conducted or that the project is referred to the Minister for referral to a mediator or a review panel. The *CEAA* provides for public participation and comments following the receipt of a comprehensive study report. If the project is not likely to cause significant adverse environmental effects or is likely to cause significant adverse environmental effects that cannot be justified, the Minister shall refer the project back to the responsible authority for the appropriate action. Where it is uncertain whether the project is likely to cause significant adverse environmental effects or where significant adverse environmental effects may be justified or where public concerns warrant a reference to a mediator or a review panel, the Minister shall refer the project to a mediator or a review panel.

(viii) Mediation and Panel Review

Although the Minister has the discretion to refer assessment of a project to a mediator, the prior consent of identified interested parties is required. However, the Minister can impose a mediator's review where a review panel recommends that all or a portion of an environmental assessment be conducted by a mediator. Following receipt of a mediator's or a review panel's report, the responsible authority may take steps required to permit the project to be carried out where it is not likely to cause significant adverse environmental effects or where significant adverse environmental effects can be justified in the circumstances. Where a project is likely to cause significant adverse environmental effects that cannot be justified, the responsible authority cannot exercise any power to permit the project to be carried out.

(ix) Joint Review Panels and Substitute Panels

The *CEAA* limits duplication of effort by permitting the Minister to enter into agreements or arrangements with other jurisdictions that have an interest in conducting an environmental assessment of a project. These other jurisdictions include a provincial government, any other agency or body established by legislatures, a body established pursuant to a land claims agreement, a government of a foreign state or any institution of such a government and any international organization of states or institution of such an organization. Where the referral of a project to a review panel is required or permitted by the *CEAA*, the Minister may permit an environmental assessment to be conducted by another federal authority where that assessment will effectively act as a substitute for the review panel required under the *CEAA*.

(x) Transboundary and Related Environmental Effects

The *CEAA* provides the Minister with broad powers to refer a project for an environmental assessment in situations where a federal authority would not otherwise

be required to conduct such an assessment if a project may cause significant adverse environmental effects in provincial, federal or international jurisdictions in which the project is not located.

(xi) Miscellaneous Matters

Section 58 of the *CEAA* permits the Minister to enter into agreements or arrangements with another jurisdiction for the purpose of harmonizing the assessment of environmental effects of projects of common interest. Presently, there are harmonization agreements in place with Alberta and Manitoba. Saskatchewan, Ontario and British Columbia are in the process of negotiating and drafting agreements. The *CEAA* sets up a public registry for the purpose of facilitating public access to records relating to environmental assessments. The responsible authority is required to ensure that the public registry contains all records produced, collected or submitted with respect to the environmental assessment.

(xii) Commentary

The *CEAA* has been praised for its clarity, its regard to cumulative and trans-border environmental effects and the inclusion of public participation in the review panel process. Some concerns have been expressed with the fact that the federal authority involved in a project ultimately is responsible for the conduct of an environmental assessment and for determining its course of action following the assessment. Moreover, there are concerns with the fact that projects can be undertaken despite significant adverse environmental effects where it can be "justified in the circumstances." Finally, the *CEAA* does not set out potential timelines for the environmental assessment process except that it must be conducted as early as practicable in the planning stages of a project and before irrevocable decisions are made. How long the process will take in any given case is undetermined.

b. *An Act to amend the Canada Oil and Gas Operations Act, The Canada Petroleum Resources Act and the National Energy Board Act and to make consequential amendments to other Acts*[4]

The principal purpose of this *Act* is to transfer to the National Energy Board authority to regulate frontier oil and gas activity, except in Nova Scotia and Newfoundland.

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[4] S.C. 1994, c. 10.

2. Regulations

a. Regulations Enacted Under the *CEAA*
Law List Regulations
Inclusion List Regulations
Comprehensive Study List Regulations
Exclusion List Regulations

The *Law List Regulations* identify statutes and regulations under which regulatory powers, duties or functions are exercised by a governmental body or agency or the Governor-in-Council, and in respect of which an environmental assessment must be conducted. The *Inclusion List Regulations* prescribe physical activities and classes of physical activities not relating to physical works that may require an environmental assessment. The *Comprehensive Study List Regulations* identify the types of major projects for which environmental assessment and comprehensive study is automatic. The *Exclusion List Regulations* prescribe the types of projects for which environmental assessment is not required.

b. *National Energy Board Act*[5]
National Energy Board Rules of Practice and Procedure, 1995[6]

The *National Energy Board Rules of Practice and Procedure, 1995* revoke and replace the previous *National Energy Board Rules of Practice and Procedure.*[7]

3. Evolving Matters

a. Regulations

(i) *National Energy Board Act*
Draft *National Energy Board Part VI Regulations, 1995*

These proposed regulations were prepublished in the *Canada Gazette* on May 6, 1995 and interested parties had until June 5, 1995 to provide comments.[8] It is anticipated that the final version of the regulations will not be in force until late 1995. These regulations relate to the National Energy Board's export and import jurisdiction under Part VI of the *National Energy Board Act.*

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5 R.S.C. 1985, c. N-7.
6 SOR/95-208.
7 C.R.C., c. 1057.
8 C. Gaz. 1995.I.1S51.

4. Information Filing Requirements

a. *National Energy Board Guidelines for Filing Requirements*

These guidelines prescribe the National Energy Board's information filing requirements which were previously included in a schedule attached to the *National Energy Board Rules of Practice and Procedure,* which are to be revoked and replaced. The information filing requirements relate to early public notification, certificates for gas pipelines, certificates for oil pipelines, s. 58 orders for gas pipelines, s. 58 orders for oil pipelines, environmental, socio-economic and lands information, s. 34 notices, leave to open, tolls or tariffs, surveillance reports, and gas export and import orders.

B. ALBERTA LEGISLATION

1. Statutes

a. *Alberta Energy and Utilities Board Act*[9]

Effective February 15, 1995 this *Act* merged the Energy Resources Conservation Board ("ERCB") and the Public Utilities Board ("PUB") into one tribunal called the Alberta Energy and Utilities Board ("AEUB"). The AEUB assumes the jurisdiction of each of the ERCB and the PUB under their respective enabling statutes. Matters which were before the predecessor tribunals before this *Act* came into force are to be continued before the AEUB. The AEUB has the same substantive and procedural powers of the ERCB and the PUB. In s. 10 of the *Act,* the AEUB has been given additional authority to make orders and impose conditions that it considers "necessary in the public interest"; to make an order granting the whole or part only of the relief applied for; and to grant partial, further or other relief where it appears to the board to be just and proper. The *Act* repealed the particular provisions of the *Gas Utilities Act*[10] which established the Gas Utilities Board and vested that board with certain and seldom-used regulatory authority.

b. *Electric Utilities Act*[11]

This *Act* will cause the restructuring of the electric energy industry in Alberta. The purposes of the *Act* include establishing a framework for a competitive market for electricity which minimizes the cost of regulation and provides incentives for efficiency. After December 31, 1995, all electric energy entering or leaving Alberta's interconnected electric system must be exchanged through the power pool which will be established in accordance with the *Act.* Electric generating units will be dispatched by a power pool administrator in accordance with relative economic merit having regard

[9] S.A. 1994, c. A-19.5.
[10] R.S.A. 1980, c. G-4.
[11] S.A. 1995, c. E-5.5.

to specified criteria. The power pool administrator will be responsible for financial settlement of electricity exchanged through the pool.

Access to all transmission facilities required to transmit electricity from generating units to electric distribution systems will be controlled by a transmission administrator. The existing transmission facilities are owned by two investor-owned utilities and two municipalities. A postage stamp rate shall be charged by the transmission administrator for each class of service.

The owner of each regulated generating unit, transmission line and electric distribution system is required to prepare a tariff, including rates, for which it must apply to the AEUB for approval. Transmission lines and electric distribution systems owned by municipalities do not ordinarily constitute electric utilities and are not subject to the requirement to prepare and file tariffs with the AEUB. Rates to be paid by the transmission administrator for use of a municipality's transmission facilities will be determined by the Minister of Energy. The transmission administrator is required to prepare a tariff, including rates, for which it must obtain the AEUB's approval.

A tariff filed with the AEUB for approval must describe how it may change over the period for which it will be in effect. It may provide for increases and decreases in rates to correspond to changes in costs. Performance-based regulation is an important element of the *Act*.

This *Act* establishes a negotiated settlement process which permits stakeholders to seek agreement on matters which are within the AEUB's jurisdiction under the *Act*. Negotiated settlements can be submitted to the AEUB for approval.

This *Act* also creates transitional amendments to the *Alberta Energy and Utilities Board Act*, the *Hydro and Electric Energy Act*,[12] the *Municipal Government Act*[13] and the *Public Utilities Board Act*.[14]

c. *Electric Energy Marketing Act Repeal Act*[15]

In conjunction with deregulation of the electric energy market in Alberta, this *Act* repeals the *Electric Energy Marketing Act*[16] effective December 31, 1995 and provides for the transition and settling of certain matters related to price or price formula adjustments regulated under the *EEMA*. The *Act* also makes transitional amendments to the *Public Utilities Board Act*.

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12 R.S.A. 1980, c. H-13.

13 S.A. 1994, c. M-26.1.

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

15 S.A. 1995, c. 11.

16 S.A. 1981, c. E-4.1 [hereinafter *EEMA*].

d. *Energy Statutes Amendment Act*[17]

This *Act* amends the *Gas Resources Preservation Act*[18] to eliminate the requirement that the Lieutenant-Governor-in-Council approve the assignment of gas removal permits by the ERCB. This *Act* also amends certain provisions of the *Gas Utilities Act* and of the *Municipal Government Act* concerning core market sales. Minor amendments to the *Natural Gas Marketing Act*[19] have been made concerning the Alberta Petroleum Marketing Commission's ("APMC") audit and record examination authority under s. 14.1, and the protection granted to the APMC and parties acting under its authority from actions or proceedings. This *Act* has made minor "housekeeping" amendments to the *Petroleum Marketing Act*.[20]

e. *Environmental Protection and Enhancement Amendment Act, 1994*[21]

This *Act* makes more than 100 "housekeeping" amendments to the *Environmental Protection and Enhancement Act*,[22] the summary of which is not practical in this article.

f. *Mines and Minerals Amendment Act, 1994*[23]

This *Act* was summarized in last year's legislative developments article.[24] It became effective on May 25, 1994. Section 10 of the *Act* will become effective on proclamation.

g. *Nova Corporation of Alberta Act Repeal Act*[25]

This *Act* was summarized in last year's legislative developments article. It became effective on June 10, 1994.

h. *Nova Corporation of Alberta Act Repeal Amendment Act, 1994*[26]

This *Act* amended the *Nova Corporation of Alberta Act Repeal Act* to permit either of the PUB or the ERCB to continue to consider complaints instituted with respect to either the rates or terms of service of Nova.

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17 S.A. 1995, c. 13.
18 S.A. 1984, c. G-3.1.
19 S.A. 1986, c. N-2.8.
20 R.S.A. 1980, c. P-5.
21 S.A. 1994, c. 15.
22 S.A. 1992, c. E-13.3.
23 S.A. 1994, c. 22.
24 L.E. Smith and L.G. Keough, "Recent Legislative and Regulatory Developments of Interest to Oil and Gas Lawyers," (1995) 33 Alta. L. Rev. 422.
25 S.A. 1994, c. 25.
26 S.A. 1994, c. 42.

i. *Oil and Gas Conservation Amendment Act, 1994*[27]

This *Act* was summarized in last year's legislative developments article. It became effective May 25, 1994.

2. Regulations

a. *Gas Utilities Act*
Gas Utilities Core Market Regulation[28]

This regulation establishes the conditions under which core consumers may obtain gas supply under a direct supply arrangement. The conditions required for such arrangements include: a minimum supply contract of at least twelve consecutive months, including any renewal periods; the payment by the core consumer to its gas distributor of compensation related to costs incurred by the distributor associated with the direct supply arrangement and a distributor's ongoing costs related to a buy-sell contract or transportation service contract; the requirement of a direct seller to have sufficient reserves to meet its aggregate direct sales obligations; the requirement of a core customer to enter into a buy-sell contract or utility transportation agreement in conjunction with gas supply contract; a requirement imposed upon the direct seller to give to core customers a corporate warranty under the gas supply contract; and the requirement that the core consumer, its agent or the direct seller be obligated to pay compensation to the distributor for failure to deliver gas to the distributor in accordance with the terms of a buy-sell contract or a utility transportation agreement. The regulation specifies the conditions upon which a core consumer may cease to obtain its gas supply under direct sales arrangements and return to the gas supply arrangements of the distributor. Distributors are granted certain rights with respect to gas purchase options from a direct seller if a buy-sell contract or utility transportation contract is terminated or otherwise discharged before the expiry of its term or the term of such arrangements expires but the core customer has failed to give proper notice to the distributor to return to the distributor's system supply.

b. *Municipal Government Act*
Municipal Gas Systems Core Market Regulation[29]

This regulation relates to direct sales arrangements which may be affected through gas systems owned by a municipality. Municipalities that operate an urban gas system may make a bylaw which would effectively prevent direct sales arrangements for all or some class of core customers. To the extent that a municipality permits direct sales, the terms and conditions governing such arrangements is essentially the same as previously described in the *Gas Utilities Core Market Regulation.*

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[27] S.A. 1994, c. 26.
[28] Alta. Reg. 44/95.
[29] Alta. Reg. 45/95.

c. *Gas Resources Preservation Act Removal of Conditions Regulation*[30]

This regulation eliminates the conditions imposed in gas removal permits by the *Permit Conditions Regulation*[31] which required permit holders to file with the Minister of Energy information concerning their downstream market arrangements.

3. Evolving Matters

a. *Special Places 2000 Policy*

On March 28, 1995, the Alberta government released its *Natural Heritage Policy — Special Places 2000.* The policy is intended to balance natural heritage preservation with three other goals, namely outdoor recreation, heritage appreciation and tourism/economic development. The policy is viewed by the government as being integral to achieving sustainable development — balancing preservation with economic growth. In the government's opinion, a prosperous province is viewed as one which can afford to preserve its natural landscape. Special Places sites will be selected to represent Alberta's six natural regions by the end of 1998. These natural regions are Rocky Mountains, Grasslands, Foothills, Canadian Shield, Boreal Forest and Parklands. A priority for nominating sites will be to ensure that all regions are fairly represented. The Rocky Mountain region is considered well represented while other regions are under-represented. Most of the land base requirements for Special Places will be identified by the end of 1996. The government has stated that a scientific and systematic process is needed to ensure that the full biodiversity of Alberta landscapes are preserved. This biodiversity includes plants, animals and the habitats in which they live.

A provincial committee consisting of diverse stakeholders will review nominated sites and, if a site is accepted, the Minister of Environmental Protection would then establish a local committee as part of the review process. Local committees will be able to contribute recommendations concerning boundary options, appropriate land use activities and management principles. Further consideration of sites will be undertaken by the proposed Provincial Coordinating Committee with input from an interdepartmental committee. Nominated sites will ultimately be reviewed by the minister and the provincial cabinet before they are designated as Special Places. A "new-and- improved" integrated resource planning process will be the mechanism for land use planning for Alberta.

The policy has been criticized by conservationists as not being adequate to protect ecological integrity. Concern has been expressed that "protected places" will not be protected if activities such as resource development are permitted within such areas. Conservationists have promoted as a preferred option the establishment of core protection areas connected by corridors in which no development would be permitted.

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[30] Alta. Reg. 53/95.

[31] Alta. Reg. 271/87.

The ultimate designation of Special Places and the establishment of an improved integrated resource planning process will provide the oil and gas industry with greater certainty as to which areas of the province will be accessible for development. What is uncertain at this time is the action conservationists may take to promote their own vision of establishing protected places within Alberta.

C. BRITISH COLUMBIA LEGISLATION

1. Ongoing Matters

a. *Environmental Assessment Act*[32]

(i) Background

The *BCEAA* will come into force on June 30, 1995. Projects which are identified as "reviewable projects" will be subjected to an environmental assessment process with three potential stages of review.

(ii) Purposes of the *BCEAA*

The *BCEAA* seeks to promote sustainability by protecting the environment and fostering a sound economy and social well-being, and to provide for the thorough, timely and integrated assessment of the environmental, economic, social, cultural, heritage and health effects of reviewable projects. Decision-making rests with the Minister of Environment, Lands and Parks and the Minister responsible for the particular type of project.

(iii) Application of the *BCEAA*

Reviewable projects under the *BCEAA* include those to be identified in draft regulations, as well as any particular project designated by the Environment Minister. All phases of a reviewable project may be assessed. This will include construction, operation and dismantling of new facilities or the modification, dismantling or abandonment of existing facilities.

(iv) Reviewable Energy Resource Projects

Based on background papers issued by the Ministry of Environment, Lands and Parks, the types of energy resource and upgrading projects which may be reviewable, subject to certain potential thresholds, are described below. The actual thresholds to be prescribed by regulation may be different.

Pipeline facilities which may be reviewable will include compressor or pumping facilities and associated terminal or storage facilities. New pipeline facilities which can transport energy with at least sixteen petajoules of combustible energy yield potential

[32] S.B.C. 1994, c. 35 [hereinafter *BCEAA*].

will be reviewable. The modification, dismantling or abandonment of existing non-exempt pipelines will be reviewable on a stand-alone basis. Special exemptions will apply to flow lines from wells, secondary lines within producing areas and distribution lines to serve ultimate customers. The *BCEAA* obviously does not apply to pipeline facilities within the jurisdiction of the National Energy Board.

Facilities which use, convert or process an energy resource, coal, wood, ethanol, methanol, hydrogen or MTBE are differentiated as between new facilities, which must have a capacity rate of energy use not less than three petajoules per year, and the modification, dismantling and abandonment of existing facilities which are reviewable on a stand-alone basis. Reviewable projects will include oil refineries, gas processing and natural gas liquid extraction plants and petrochemical plants. Exempt facilities include production facilities such as compressors, separators and dehydrators.

The drilling, operation and abandonment of oil or gas wells is not included within the list of reviewable projects. Offshore platforms or artificial islands to be used for oil and gas exploration will be reviewable under all circumstances.

Electric transmission lines with a voltage greater than 500 kilovolts and associated substations are reviewable for new facilities or the addition to existing facilities. New power plants or facility additions which have a capacity output of at least twenty megawatts will be reviewable. Power plants will include hydro-electric, thermal, solar, wind and tidal facilities.

Energy trans-shipment terminals or storage facilities, where energy is stored in bulk as part of a transportation process, will be reviewable for new facilities if the facility can store energy with no less than thirty petajoules of combustible energy yield potential or for additions to existing facilities which will be reviewable on a stand-alone basis. Naturally occurring underground storage reservoirs in northeast British Columbia will be exempt.

(v) The Environmental Assessment Process

The three potential stages for review are: first, the review of the initial application which will lead to a decision by the Ministers to either issue a project approval certificate (and permitting the proponent to apply for necessary permits and licenses), to deny the project, or to require further review; second, the project report preparation and review stage which, like stage one, will lead to a decision by the Ministers to either issue a project approval certificate, deny the project or require further review; and third, an Environmental Assessment Board hearing.

(vi) Project Committee

After the proponent of a reviewable project applies for a project approval certificate, the executive director will review the application to determine if it meets the requirements of the *BCEAA* and, if it is accepted, the executive director must establish a "project committee" and invite each of the following to nominate representatives: the

government of British Columbia, the government of Canada, any municipality or regional district in the vicinity of the project, any first nation whose traditional territory includes the site of the project or is in the vicinity of the project and any of British Columbia's neighbouring jurisdictions in the vicinity of the project.

The project committee's role is to advise the executive director and the Ministers about the public input, recommendations, potential impacts of the project and their mitigation. The executive director has the discretion to establish a public advisory committee representing individuals or representatives of organizations interested in the outcome of the review of the application. The public advisory committee can determine its own procedures and invite participation from the project committee.

(vii) Stage One Review

In a stage one review, the public will have between thirty and sixty days to comment on the potential effects of the project, after which the government review of the application will be completed within forty days. The executive director, on the recommendation of the project committee, must then either refer the application to the Ministers for the decision to either approve or deny the application or make an order that a project report be prepared as part of the stage two review. The Ministers must give written reasons for the decision to the proponent. For the stage one process, the proposed timelines range between a maximum duration of 151 days or a best possible case of eighty-two days. The best case assumes the government takes 50 percent of the allotted time to complete its tasks and that the public review period is set at the minimum allowable period.

(viii) Stage Two Review

If a project proceeds to a stage two review, the executive director must, within twenty days, prepare the project report specifications in draft form which are provided to the proponent and subjected to a fifteen to thirty-day public comment period. Thereafter, the project report specifications are finalized within twenty days and a project report — likely requiring between three and eighteen months to complete — will be prepared by a proponent.

If the project report is accepted by the executive director, it will be made available for public review and comment during a forty-five to sixty-day period and a proponent may make application for other approvals which are required for the project. The process contemplates that such applications will be considered concurrently with the continuing environmental review under the *BCEAA*. Following the public review, the government review is to be completed within seventy days and thereafter, based on the recommendation of the project committee, the executive director must refer the application to the Ministers for a decision. In making the referral, the executive director must take into account the application, the project report and any comments received about them. A referral to the Ministers may be accompanied by recommendations of the project committee. The Ministers must, within forty-five days, either issue a project approval certificate, refuse to issue the project approval certificate or refer the

application to the Environmental Assessment Board for a public hearing. The Ministers are required to give written reasons for their decision. The estimated timeline for the completion of a review to the end of stage two is between twelve and thirty months.

(ix) Stage Three Public Hearing Review

If a stage three public hearing review is conducted before the Environmental Assessment Board, the Ministers must specify draft terms of reference for the public hearings within thirty days of referring the project. The draft terms of reference are subject to a thirty to sixty day public comment period and final terms of reference are established by the Ministers within thirty days of the end of the public review period. After the Environmental Assessment Board concludes the public hearing, it must submit a written report to the Lieutenant-Governor-in-Council with its recommendation on whether to issue or refuse the project approval certificate. If the Board recommends approving the certificate it may include recommendations on preventing, mitigating or monitoring impacts. If the terms of reference finalized by the Ministers included consideration of other approvals applied for by the proponent, the Board may recommend the issuance of such approvals and any conditions to be attached.

The Lieutenant-Governor-in-Council must order either that the project approvals certificate be issued subject to any conditions specified or that the project approval certificate be refused. The Lieutenant-Governor-in-Council's decision is final and binding. The Lieutenant-Governor-in-Council may also order that other approvals applied for be issued, subject to any conditions specified. If the Lieutenant-Governor-in-Council makes an order requiring the issuance of other approvals, any person, board, tribunal or agency that has authority or power to decide the issues related to such approvals must issue such approvals in accordance with the Lieutenant-Governor-in-Council's orders, despite anything specified in other legislation. Such other approvals are final and binding and are not subject to review or appeal under such other legislation.

(x) Total Timelines

A project which must be considered at a public hearing could take between eighteen and forty-two months in total to complete all three stages of review.

b. Regulations to be Made Under the *BCEAA*

Two draft regulations, which are not yet available to the public, will be finalized when the *BCEAA* comes into force on June 30, 1995. One regulation will specify the types and threshold sizes of projects which will be reviewable. The other regulation will establish the timelines for each stage of review.

III. REGULATORY DEVELOPMENTS

A. FEDERAL

1. National Energy Board

a. Decisions

i. Natural Gas Export Decisions

(A) Introduction

In 1994, the National Energy Board (the "NEB") conducted two gas export licence hearings in which the scope of the NEB's environmental assessment responsibilities were clarified. In January of 1994, the GH-5-93[33] proceeding considered applications by Brooklyn Navy Yard Cogeneration Partners, L.P. ("Brooklyn"), Husky Oil Operations Ltd. ("Husky"), ProGas Limited ("ProGas"), Shell Canada Limited ("Shell") and Western Gas Marketing Limited ("WGML"). In March, 1994, the NEB granted a review of its GH-5-93 decision on the application of Rocky Mountain Ecosystem Coalition ("RMEC").[34] Commencing in September 1994, the NEB heard applications from CanStates Gas Marketing, Chevron Canada Resources, Renaissance Energy Ltd., and Western Gas Marketing Limited in the GH-3-94[35] proceeding.

(B) GH-5-93 Hearing

The GH-5-93 decision is the backdrop for the NEB's subsequent full analysis of its environmental assessment responsibilities. RMEC argued that an environment assessment, broad in scope and including a review of upstream environmental effects, was required under the *EARP Order* because of an alleged causal relationship between export applications and upstream environmental effects which impair ecosystem integrity and biodiversity. The NEB responded by following the Federal Court of Appeal decision in *Quebec (Attorney General)* v. *Canada (National Energy Board)*[36] that related to an electricity export licence application by Hydro-Quebec. In that decision, the Federal Court of Appeal overruled the NEB's exercise of jurisdiction to

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33 *In the Matter of Brooklyn Navy Yard Cogeneration Partners, L.P., Husky Oil Operations Ltd., ProGas Limited, Shell Canada Limited, Western Gas Marketing Limited, Applications Pursuant to Part VI of the National Energy Board Act for Licences to Export Natural Gas and; ProGas Limited, Applications Pursuant to Section 21 and Part VI of the National Energy Board Act to Amend Two Licences to Export Natural Gas* (February 1994), No. GH-5-93 (N.E.B.).

34 *In the Matter of Review of the Applications for Gas Export Licences from Brooklyn Navy Yard Cogeneration Partners, L.P., Husky Oil Operations Ltd., ProGas Limited, Western Gas Marketing Limited*, An Application dated 7 March 1994 from Rocky Mountain Ecosystem Coalition for a review of the GH-5-93 decision made by the National Energy Board in February 1994 (June 1994) No. GH-5-93 Review (N.E.B.).

35 *In the Matter of CanStates Gas Marketing, Chevron Canada Resources, Renaissance Energy Ltd. and Western Gas Marketing Limited, Applications Pursuant to Part VI of the National Energy Board Act for Licences to Export Natural Gas* (November 1994), No. GH-3-94 (N.E.B.).

36 [1991] 3 F.C.R. 443 (F.C.A.).

consider upstream environmental impacts of electricity exports and held that the NEB's environmental assessment jurisdiction was limited to a consideration of the environmental effects of sending electricity from Canada. The NEB advised RMEC that consideration of any causal relationship between gas export applications and upstream environmental effects did not fall within the bounds of its jurisdiction. The NEB granted the export applications.

(C) GH-5-93 Review Proceeding

Following the release of the GH-5-93 decision, the Supreme Court of Canada overturned the Federal Court of Appeal in *Quebec (Attorney General)* v. *Canada (National Energy Board)* in a decision now called *The Grand Council of the Crees (of Quebec) and The Cree Regional Authority* v. *Canada (Attorney General)*.[37] The *Hydro-Quebec* decision confirmed the NEB's jurisdiction to consider upstream environmental effects in the electricity export decision-making process. RMEC applied to the NEB for a review of the GH-5-93 decision following the Supreme Court of Canada's ruling. The NEB agreed to conduct a review.

In the GH-5-93 Review decision, the Board set out the crux of the issue as follows:

> The Board is of the view that what is at issue in this instance, is the scope of the environmental assessment to be undertaken by gas export licence applications. More particularly, do the environmental implications of a gas export proposal to be considered under the EARP Guidelines Order include the environmental effects of related activities or projects, such as upstream production, processing and transportation facilities or downstream facilities?[38]

Following its examination of the written submissions filed in the review proceeding, the NEB established the following two-step test for determining whether a gas export license application will trigger an environmental assessment:

(1) future upstream facilities or activities are not reviewable unless they have the potential to have an environmental effect on an area of federal responsibility; and

(2) there must be a direct connection or proximity between such upstream facilities or activities and the export of gas ("necessary connection").

The NEB also held that the *EARP Order* does not have extraterritorial effect and therefore does not give the NEB jurisdiction to consider the environmental effects of the end use of gas. In developing its test, the NEB carefully reviewed the nature of the oil and gas industry and recognized such factors: as the diversity and developed state of the infrastructure for producing and delivering gas; the deregulated gas marketplace, the diverse and independent participants involved in the industry which results in complex intervening activities; and ownership changes between production and the end

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37 [1994] 1 S.C.R. 159 [hereinafter *Hydro-Quebec*].

38 *Supra* note 34 at 21.

use of gas and the multiple legislative jurisdictions that are involved in the gas industry. Based on those factors, the NEB concluded that where a gas supply was not identifiable and could come from numerous sources at any given time, a necessary connection cannot be established and any project having that form of gas supply would not be subject to environmental screening.

The NEB upheld its licensing decisions related to the applications by Brooklyn, ProGas and WGML. After receiving further information from Husky, the NEB concluded there was no necessary connection and upheld its earlier approval. With respect to the application of Shell, the NEB found there could be a necessary connection and it imposed certain conditions in Shell's export license. Shell is required to file information concerning any "new identifiable facility to be constructed and operated or any new identifiable activity to be undertaken to supply the gas for export" to the extent that such facilities or activities "could have an environmental effect on areas of federal jurisdiction."[39]

(D) RMEC's First Leave Application

RMEC originally filed an application for leave to appeal the NEB's decision in the GH-5-93 proceeding for the NEB's refusal to consider evidence of upstream environmental impacts. Following release of the NEB's GH-5-93 Review decision, RMEC amended its leave application to take issue with the NEB's necessary connection test. The leave application was denied.

(E) GH-3-94 Hearing

This lengthy gas export licence hearing lasted nineteen days. The hearing was characterized by protracted questioning by environmental intervenors concerning environmental impacts, gas supply sufficiency and compliance with NEB information filing requirements. Furthermore, those intervenors made a series of motions requesting adjournments, seeking clarification of evidentiary matters and establishing jurisdictional authority. The NEB provided wide latitude for representations on the motions and the key issues affecting the hearing. The NEB's decision, in which it granted the applied-for licences, addresses each of the motions and the positions of the respective parties on the key issues addressed. Certain of these motions and the rulings are discussed below.

One of the main motions made by the environmental intervenors was for the NEB to consider the environmental effects on the global commons of the end use in the United States of the gas to be exported. The NEB determined that neither its legislation or regulations nor the *EARP Order* established any explicit jurisdiction to review the environmental effects originating outside Canada. Accordingly, the motion to compel production of an environmental assessment conducted in the United States pertaining to the end use of some of the gas sought to be exported was not admitted.

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[39] *Ibid.* at 51.

A further motion sought to create a panel comprised of NEB staff members for the purpose of cross-examination on the NEB supply demand reports and export impact assessments that were prepared pursuant to the NEB's mandate under the *National Energy Board Act*. The NEB dismissed this motion on the basis that an applicant utilizing the NEB's technical reports had to submit their experts to cross-examination and be in a position to speak to those reports and draw their own conclusions. Moreover, the technical reports prepared by the NEB's staff sufficiently disclosed their methods of analysis and assumptions to enable both applicants and intervenors to fully consider, question and test the merits of the reports. Finally, placing the NEB staff members on the witness stand would effectively require the NEB to consider the credibility of its staff advisors and to assess the weight of the technical reports presented. The NEB was of the view that such a process would seriously compromise the traditionally unified view of the NEB as being comprised of members and staff.

The last substantial motion addressed the NEB's direction that it would not consider evidence of upstream environmental impacts until it had determined whether or not a necessary connection exists, a decision which would be made after the conclusion of the oral hearing. Counsel for RMEC argued that the NEB must hear evidence of the upstream environmental and socio-economic effects during the evidentiary portion of the proceedings. The NEB denied that application and ruled "that issues with respect to upstream environmental impacts could not be addressed until the Board had decided on whether or not a direct connection or necessary proximity existed between any new upstream facilities and the export proposals."[40] Prior to determining the direct connection issue, the preliminary receipt of the intervenors' general information on environmental and socio-economic effects related to gas production could possibly create a prejudice.

In final argument, submissions were presented by the applicants and the intervenors on the nature and scope of the necessary connection test to be applied by the NEB prior to considering upstream environmental effects. In the GH-3-94 decision, the NEB found that there was no necessary connection between new upstream facilities and activities of the applicants and their respective export licence requirements. Therefore, no further environmental assessment was required. In this decision, the NEB noted the environmental intervenors submitted a considerable body of evidence on alleged upstream environmental effects. Given the NEB's position requiring evidence on the threshold issue of direct connection, the evidence submitted on upstream environmental effects was not considered.

The NEB defined and limited the type of necessary connection required between new upstream facilities or activities and the export license. The NEB determined "that for the necessary connection to exist, the export license and the new upstream facilities or activities must be integrated to the extent that they can be seen to form part of a single course of action."[41]

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40 *Supra* note 35 at 12.

41 *Ibid.* at 23.

Some intervenors had argued that the NEB's use of the Market-Based Procedure ("MBP") to satisfy its gas surplus determination mandate under s. 118 of the *National Energy Board Act* constituted a fettering of the NEB's discretion. In response to this argument, the NEB concluded that the establishment of the MBP as an overall policy or guideline did not fetter its discretion in determining the gas surplus issue so long as each decision was made on the merits of the particular application under the MBP format. A determination by the NEB as to the issue of surplus based on the requirements set out in the MBP satisfied its duties under s. 118 of the *National Energy Board Act*.

The NEB approved the applied-for licences.

(F) RMEC's Second Leave Application

RMEC filed an application for leave to appeal the NEB's decision in the GH-3-94 proceeding because the NEB made a finding of no direct connection in respect of each application and because of its refusal to consider environmental evidence. RMEC argued that the NEB had a statutory mandate to make decisions that are in the public interest and that it had to consider environmental factors in export applications in order to discharge its mandate. RMEC argued further that the NEB failed to have regard to highly relevant evidence, that being environmental evidence, and therefore it failed to meet its obligations under s. 118 of the *National Energy Board Act*, which provides that the NEB "shall have regard to all considerations that appear to it to be relevant" in deciding whether to issue export licenses. This leave application was also denied.

ii. *Foothills Pipe Lines (Alta.) Ltd. Application for the Wild Horse Pipeline Project*[42]

(A) Introduction

Foothills Pipe Lines Ltd. filed, on behalf of Foothills Pipe Lines (Alta.) Ltd. ("Foothills"), an application with the NEB for a certificate of public convenience and necessity authorizing the construction of a natural gas transmission line in southeastern Alberta. The proposed Wild Horse Pipeline is designed to provide export capacity at the international border near Wild Horse, Alberta to serve markets in the United States and northern Mexico.

(B) Preliminary Matters

In dealing with the preliminary matter of the completeness of the application the NEB noted that having set the matter down for hearing it was manifest that the NEB had made a determination that the application was sufficiently complete to be considered and that relief from the comprehensive filing requirements had, in effect,

[42] *In the Matter of Foothills Pipe Lines (Alta.) Ltd., Application dated 30 June 1994 for the Wild Horse Pipeline Project* (January 1995), No. GH-4-94 (N.E.B.).

been granted. The NEB held that it is a question of fact for it to decide whether an applicant has complied with filing requirements in any particular case.

(C) Uniqueness of this Application

This application and its approval by the NEB is unique in that the project was not supported by firm transportation agreements, project specific supply data or project-specific market data. This type of information usually underpins a determination by the NEB that new facilities are needed. The NEB agreed with Foothills' position that there will be sufficient overall gas supply to support the long-term use of the pipeline and that sufficient overall market demand will exist from the Western Market Centre proposed to be served by the pipeline.

(D) Conditions for Construction

The NEB imposed certain conditions in the certificate granted to Foothills which must be met in order for the project to proceed. These conditions included a requirement that executed unconditional firm service agreements with a minimum term of fifteen years for the full capacity of the pipeline be filed with the NEB before construction can commence. The NEB also imposed a sunset clause, such that the certificate will expire on June 30, 1997 if construction has not been commenced by that date.

(E) Observations

This decision is significant in that it offers a more flexible approach for pipeline companies to develop new facility projects. Given the restrictions imposed by typical certificate conditions, pipelines cannot be constructed without all supporting contracts and regulatory approvals. Thus, if the market gives its support to a proposed project, it will be on the basis of available supply and markets. It is the existence of these elements which will dictate whether certificate conditions can be met and a project can proceed. This decision represents a common sense, market-based approach to project development.

iii. *Multi-Pipeline Cost of Capital Decision*[43]

(A) Introduction

In response to its concerns with respect to improving the efficacy of the pipeline toll-setting process, the NEB issued a hearing order to eight of the Group 1 pipelines, namely Alberta Natural Gas Company Ltd. ("ANG"), Foothills Pipe Lines Ltd. ("Foothills"), Interprovincial Pipe Line Inc. ("IPL"), TransCanada PipeLines Limited

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[43] *In the Matter of TransCanada PipeLines Limited, Westcoast Energy Inc., Foothills Pipe Lines Ltd., Alberta Natural Gas Company Ltd., Trans Québec & Maritimes Pipeline Inc., Interprovincial Pipe Line Inc., Trans Mountain Pipe Line Company Ltd. and Trans-Northern Pipeline Inc. in respect of cost of capital* (March 1995), No. RH-2-94 (N.E.B.).

("TransCanada"), Trans Mountain Pipe Line Company Ltd. ("TMPL"), Trans-Northern Pipeline Inc. ("TNPI"), Trans Québec & Maritimes Pipeline Inc. ("TQM") and Westcoast Energy Inc. ("Westcoast"), setting out the issues to be addressed in a multi-pipeline cost-of-capital hearing. In convening the hearing, the NEB wished to consolidate the previously individualized cost-of-capital hearings into one "generic hearing where all pipeline companies would make their cases simultaneously using a consistent set of financial parameters." Additionally, the NEB wished to avoid unnecessary, repetitive and expensive annual rate hearings, and to this end, requested evidence on an appropriate mechanism whereby the return on common equity would be adjusted automatically, without the need for a NEB hearing. TNPI and IPL were subsequently discharged from the proceedings.

The hearing and resultant decision dealt with three main issues: (1) rate of return on common equity; (2) capital structure of the individual pipelines; and (3) post-1995 adjustment mechanism and review.

(B) Return on Common Equity

Following a discussion of the relative merits of the comparable earnings technique, the discounted cash flow method and the equity risk premium analysis, the NEB concluded that the equity risk premium analysis was the preferred method to be used in determining the standard rate of return on common equity. This standard rate of return would be applied to all pipelines subject to the proceedings. The NEB approved a standard rate of return of 12.25 percent for the 1995 test year, taking into account the upper end of the recommended long-term Government of Canada bond rate of 9.25 percent, in combination with an equity risk premium, set by the NEB at 300 basis points. In setting this latter figure, the NEB stated:

> [We] are of the view that the equity risk premium for the market as a whole is 450 to 500 basis points. In arriving at this conclusion, the Board gives some weight to the concept of "purchasing power risk" or "maturity risk", but acknowledges that specific quantification of this factor is lacking.... After adjusting for the relatively lower risk of the benchmark pipeline and adding a modest allowance for financial flexibility (which includes flotation costs), the Board is of the view that a reasonable all-inclusive equity risk premium for the benchmark pipeline would be 300 basis points.[44]

(C) Capital Structure

With respect to the capital structure of the individual pipelines, the NEB considered evidence from each pipeline as to its various business and financial risks. These risks, the pipelines argued, necessitated a relatively high common equity ratio. After considering the evidence, the NEB found that a 30 percent common equity ratio was appropriate for each of TransCanada, Foothills, ANG and TQM, a 35 percent common equity ratio was appropriate for Westcoast, and a 45 percent deemed common equity ratio was appropriate for TMPL, all effective January 1, 1995.

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[44] *Ibid.* at 6.

Prior to its setting of such ratios, the NEB outlined certain general principles to be taken into account when determining a pipeline's capital structure. Particularly, the exercise must start with an analysis of a pipeline's business risk. This analysis is highly subjective, and thus best expressed qualitatively, and not in exacting and precise figures. Other factors to be considered include financing requirements, the size of the pipeline, the ability of a pipeline to access various financial markets and the realities of market forces, the latter despite the assurances provided by regulation.

(D) Adjustment Mechanism

The most noteworthy aspect of the NEB's decision is the implementation of a simplified procedure for effecting adjustments to the allowed rate of return on common equity. The NEB approved an annual adjustment mechanism based on changes in forecast long-term Government of Canada bond yields, which had the following characteristics:

> (1) the test-year bond yield forecast will be the average of the 3-months-out and 12-months-out 10-year Government of Canada forecast published in the previous year's November issue of *Consensus Forecasts* plus the actual 10-year to 30-year bond yield spread in October of that year;
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> (2) the change in forecast bond yields will be multiplied by a factor of 0.75 to arrive at the adjustment to the rate of return on common equity; and
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> (3) the adjusted rate of return on common equity will be rounded to the nearest 25 basis points.[45]

The NEB expressly stated that it "does not expect to reassess the rate of return on common equity in a formal hearing for at least three years," as it believed that the adjustment mechanism "will prove robust over a wide range of interest rates."[46] Although the NEB is not inclined to undertake routine reassessments of capital structures, it will reassess the capital structures of individual pipelines in the event that significant economic changes warrant such reassessment.

iv. *Interprovincial PipeLine Inc. System Apportionment Inquiry*[47]

(A) Introduction

In response to an application filed by Interprovincial Pipe Line Inc. ("IPL"), the NEB set down a hearing to examine the issue of controlling the escalating levels of apportionment of capacity on the IPL pipeline system, caused largely by overnominations. Apportionment had reached a record level of 77 percent for the month prior to the hearing. Alternative proposals were filed by the Canadian Association of

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45 *Ibid*, Overview, at (ix).

46 *Ibid.* at 32.

47 *In the Matter of IPL Inc.; an Inquiry Pursuant to Subsection 24(3) of the NEB Act into Apportionment on the Interprovincial Pipe Line Inc. System* (April 1995), No. MH-1-95 (N.E.B.).

Petroleum Producers ("CAPP"), Novacor Chemicals (Canada) Ltd. ("Novacor") and the Petroleum Shippers Group ("PSG").[48] A joint proposal by CAPP and the PSG was subsequently filed. IPL withdrew its initial proposal and supported the joint CAPP/PSG proposal, with some minor exceptions. During the hearing, the NEB considered the merits of the Novacor proposal and the joint CAPP/PSG proposal. The NEB substantively approved the CAPP/PSG proposal, and ordered that the IPL tariff be amended accordingly.

(B) Novacor Proposal

The Novacor proposal recommended a system of tender verification for deliveries into the IPL pipeline system, whereby historical receipts from each feeder pipeline would be used to calculate the monthly "tender target" for that feeder pipeline. The tender target would then represent the volume of acceptable receipts from that feeder into the IPL system. Feeders would be responsible for allocating an equitable sharing among their shippers of the feeder pipeline capacity not to exceed the tender target. Novacor also contemplated a non-performance penalty of $1.50 per barrel to be paid in the event that a shipper's approved nomination on the IPL system was not fully utilized, subject to events of *force majeure*.

(C) CAPP/PSG Proposal

The CAPP/PSG proposal contemplated two components: first, a non-performance penalty of $1.36 per barrel to be paid by shippers who have delivery shortfalls of greater than 5 percent of the nomination approved by IPL; and secondly, a strict *force majeure* provision which would excuse the non-delivery by a shipper (and thus the payment of the non-performance penalty) only in the case of certain events. In an attempt to educate the industry and deter overnomination, the proposal recommended that all *force majeure* claims be published on a monthly basis. The CAPP/PSG proposal was widely supported by members of the industry, as well as by the Alberta Department of Energy, which, in a letter of comment submitted to the NEB, indicated its willingness to assist in reducing artificial levels of apportionment.

(D) The NEB's Decision

For three reasons, the NEB found that the CAPP/PSG proposal was preferable to that of Novacor: first, the Novacor proposal would transfer the majority of the responsibility to the feeder pipelines, who may not in fact be able to accommodate this responsibility; second, the use of historical receipts as the basis for tender targets rendered the Novacor proposal inflexible to adapt to changes in the market; and third, in contrast to the Novacor proposal, the CAPP/PSG proposal was widely supported, a factor which the NEB considered "an important determinant of [the proposal's ultimate] success."

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48 PSG was comprised of Chevron Canada Resources, Imperial Oil Limited, Koch Oil Co. Ltd., Murphy Oil Company Ltd., Petro-Canada and Shell Canada Limited.

The NEB, based on the arguments of IPL, made a minor modification to the proposed CAPP/PSG *force majeure* definition and increased the non-performance penalty from $1.36 to $2.70 per barrel — an amount which the NEB believed would act as a greater deterrent to overnomination.

(E) Effect of the New Procedures

As a result of the implementation of the changes to IPL's tariff as ordered by the NEB, apportionment on the IPL pipeline system dropped from 77 percent to 7 percent in May 1995, and to 0 percent in June 1995. The June figure "mark[s] the first time shipper nominations have not exceed capacity in 3.5 years."[49] Accurate nominations will permit IPL to assess accurately the need for capacity increases. If some level of "real" apportionment is experienced, it will indicate a shortfall in required capacity.

v. *Westcoast Energy Inc. Application for the Aitken Creek Facilities*[50]

(A) Introduction

Westcoast Energy Inc. ("Westcoast") applied to the NEB for, *inter alia*, a certificate of public convenience and necessity authorizing Westcoast to construct and operate certain gas facilities in the Aitken Creek area of northeastern British Columbia. The proposed facilities included four additional raw gas transmission loops, three new compressor facilities for that raw gas, a new processing plant at Aitken Creek and a new loop of the Aitken Creek line connecting the proposed plant with the existing main transmission line of Westcoast.

(B) The NEB's Majority Decision

The NEB majority dismissed the application of Westcoast on the basis that it did not have jurisdiction over the proposed facilities, except for the new loop of the Aitken Creek line which would connect with the main transmission line of Westcoast. The majority determined that it did not have jurisdiction over the new gathering and processing facilities of Westcoast, although similar facilities have historically been regulated by the NEB. Until this application, the general jurisdiction of the NEB over such facilities had not been formally challenged.

(C) B.C. Gas' Constitutional Challenge

In posing the constitutional challenge to the application, B.C. Gas Utility Ltd. ("BC Gas") argued that the federal undertaking operated by Westcoast which fell under federal jurisdiction was the interprovincial and international transmission of natural gas. However, that undertaking was separate and distinct from the gathering and processing of natural gas, which are activities that are not interprovincial or international, are not

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49 "June Apportionment Shrinks to Zero" *Daily Oil Bulletin* (23 May 1995) at 1.

50 *In the Matter of an Application dated 6 October 1994, as amended, by Westcoast Energy Inc. for the Fort St. John Expansion Project* (May 1995), No. GH-5-94 (N.E.B.).

integral to Westcoast's federal undertaking (*i.e.*, mainline transmission) and thus do not fall within federal (NEB) jurisdiction.

(D) Westcoast's Argument

To the contrary, Westcoast argued that the NEB could not segregate its entire system into component parts, which would then be regulated by differing bodies. Moreover, the gathering and processing facilities were an integral part of Westcoast's mainline transmission system, and thus the entire system, including gathering and processing, was a federal undertaking and fell within the jurisdiction of the NEB. The NEB, argued Westcoast, had no basis to consider the gathering and processing facilities as a separate and distinct, and thus differently regulated, undertaking. The arguments of Westcoast were supported by the Aitken Creek Group, an intervenor in the proceedings.

(E) The Majority's Reasoning

In rendering its landmark decision, the NEB majority found that:

> gas processing and gas transmission are fundamentally different activities or services. Processing is one of the operations that results in the production of residue gas, sulphur and liquids, which are then transported to markets by various means. Gathering is a transportation activity, but in the view of the Board it is related to the production process rather than the mainline transmission activity.[51]

As such, the NEB majority held that the proposed facilities, with the exception of the one proposed loop connecting with the mainline, were an undertaking independent of Westcoast's mainline transmission system. Because the proposed gathering and processing facilities were a distinct undertaking, were not integral to the operation of the mainline system, and the facilities themselves were not interprovincial or international in scope, the majority held that they did not fall within the NEB's jurisdiction under s. 92(10) of the *Constitution Act, 1867*.

(F) Dissenting Opinion

Notably, a dissent was rendered as to the NEB's decision on jurisdiction. In the dissenting member's view, "the entire Westcoast system is one indivisible undertaking."[52] The dissent went on to consider the legal implications of treating the gathering and processing facilities as separate and distinct from the mainline transmission system. With respect to the gathering facilities alone, the dissent concluded that, because parts of the gathering system extended interprovincially, the gathering component fell within federal jurisdiction under s. 92(10). Moreover, with respect to the processing facilities, the dissent stated that "Westcoast's processing services are provided solely for its shippers and are essential to the transmission of gas.... Similarly, Westcoast's processing plants are essential to the transportation of gas to market; they

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51 *Ibid.* at 9.

52 *Ibid.* at 13.

are provided solely for the benefit of shippers on the system."[53] On this reasoning, the dissenting member found that the processing facilities were integral to the operation of the federal undertaking, that is the mainline transmission system, and thus fell within federal jurisdiction under s. 92(10). Additionally, noted in dissent was the deference that should be given in this particular case to the historical regulation of the entire Westcoast system by the NEB, such that the "[p]roducers who planned on using the Aitken Creek plant and the related gathering system expansions made exploration and development investments based on the current regulatory regime ... [and should] expect stability in that regard."[54]

vi. *Interprovincial Pipe Line Inc.'s Incentive Toll Methodology*[55]

(A) Introduction

Interprovincial Pipe Line Inc. ("IPL") applied to the NEB for the approval of a toll settlement reached between IPL and the Canadian Association of Petroleum Producers ("CAPP") as a result of extensive negotiations between the parties. The settlement was based on incentive toll principles, whereby IPL and tollpayers would not only share the benefits associated with cost-savings achieved by IPL, but also those associated with increased revenues resulting from higher than anticipated throughput on IPL's pipeline. In an unprecedented but welcome move away from traditional cost-of-service regulation, the NEB approved the proposed toll settlement.

(B) Framework of the Negotiated Settlement

IPL included in its application materials an "Incentive Settlement Explanatory," which included, *inter alia*, a description of the general framework of the negotiated settlement, and which set out the "building blocks" of the settlement as follows:

- First, a negotiated *revenue requirement* (exclusive of tax allowance) has been established for 1995, and is proposed to be escalated year over year based on the change in the rate of the Consumer Price Index for Canada.
- Second, a mechanism is established whereby *cost savings* realized in a year which exceed a negotiated earning threshold will be allocated between IPL and as a reduction to the following year's revenue requirement. This mechanism has been termed "Cost Performance Benefit Sharing." The cost performance sharing mechanism provides benefits to both IPL and tollpayers in the event savings are achieved.
- Third, IPL and tollpayers will benefit from an *allocation of additional net revenue* associated with throughput which exceeds a negotiated level, thereby providing an additional incentive for

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[53] *Ibid.* at 14-15.

[54] *Ibid.* at 17.

[55] *In the Matter of an Application by Interprovincial Pipe Line Inc. ("IPL") for Orders under Part IV of the Act approving a Negotiated Settlement respecting an Incentive Toll Methodology and Associated Tolls and Tariffs*, (February 1995), File No. 4200-J00106.

IPL to maximize throughput on the system. This incentive mechanism is called "Capacity Sharing".

- Finally, variations between forecast and actual *transportation revenue* are reflected in the revenue requirements of subsequent years by means of a "Transportation Revenue Variance" mechanism.[56]

According to IPL, "[t]he net effect of the incentive elements of the settlement is that IPL assumes the downside risk and shares the upside benefit with respect to operating and capital costs, while tollpayers do the same in respect of throughput risk."[57]

(C) Annual Filing Requirements

The proposal also contemplated that IPL would file new tariffs annually with the NEB. This filing would contain details and calculations of the tolls in effect for the following year. This annual filing was intended to replace all current monthly and quarterly toll filing requirements of NEB Board Order TO-7-90.

(D) Adjustments

The principles of the settlement also would allow for adjustments to be made to the annual revenue requirement and resulting tolls in the event of the occurrence of significant or unforeseen events.

(E) Term of the Settlement

Although the settlement contemplated that the incentive toll methodology would continue indefinitely, the specific toll parameters set by the parties are for the years 1995 to 1999, inclusive. The parties intend to negotiate post-1999 tolls in 1997.

(F) Observations

As evidenced in the report submitted by National Economic Research Associates, Inc. to IPL, which was contained within IPL's Application Materials, the NEB's approval and implementation of the incentive toll methodology settlement is a step favoured by many industries in the United States and elsewhere, and echoes the move toward deregulation and efficiency in increasingly competitive market environments.

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56 "Incentive Settlement Explanatory," *ibid.* at 2 [emphasis added].

57 *Ibid.*

B. ALBERTA

1. Energy Resources Conservation Board (now the Alberta Energy and Utilities Board)

a. Decisions

i. *Syncrude Continued Improvement and Development Application*[58]

(A) Introduction

Syncrude Canada Ltd. ("Syncrude") applied to the ERCB to amend its existing Approval for the Mildred Lake Oil Sands Plant to, among other things, increase its current synthetic crude oil production limit and to obtain approval of conceptional mining, lease development and reclamation plans. The major environmental and social intervenors were Syncrude Environmental Assessment Coalition ("SEAC"), an environmental network group formed for the purpose of the hearing, as well as the Fort McKay First Nation ("Fort McKay"), the Athabasca Chipewyan Band 201 ("ATC") and the City of Fort McMurray. The ERCB identified and addressed three main issues, namely:

(1) technical issues involving production capability, expansion technology and bitumen supply;
(2) environmental issues including atmospheric emissions, management of processing by-products called fine tails and reclamation plans, and
(3) socio-economic issues including employment and business opportunities for native communities, compensation for impacts to native communities and infrastructure concerns of the City of Fort McMurray.

(B) Syncrude's Position

Syncrude tendered substantial technical evidence to support its application. It argued that existing processing technology continued to be the most advanced and, with modifications and improvements, could ultimately increase production by as much as 45 to 76 percent over existing limits. To fulfil the anticipated increase in production, Syncrude sought approval for additional mining areas within the approved project boundary and requested the ability to import bitumen for processing depending on production levels reached. Extension of the project expiry date would increase the value of project assets and would thus increase investor confidence for future development or expansion.

As might be expected, the environmental issues proved to be some of the most contentious in the hearing. Syncrude acknowledged that cumulative emissions over the expanded life of the plant would increase; however, Syncrude was implementing and

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[58] *Syncrude Continued Improvement and Development Project, Mildred Lake Oil Sands Plant* (July 1994), No. D 94-5 (E.R.C.B.).

would continue to implement control technology to reduce main stack emissions and to better control flaring and diverting emissions of pollutants. Syncrude identified other forms of emissions that could be controlled by improved energy efficient utilization of the processing equipment. Syncrude recognized the efforts of the federal government to reduce or stabilize certain emissions, but indicated that no individual region, individual industry, or individual company is required to hold emissions to some previous level. Further, although Canada's negotiations under international commitments called for the use of best available technology, Canada had argued against the retrofit of such technology for existing facilities.

Syncrude put forward studies examining the vegetative effects of soil acidification, the ambient air quality in the Fort McMurray region and the health impacts predicted from long-term exposure to Syncrude emissions. In Syncrude's view, each of those studies supported the position that present levels and predicted future levels of emissions would have limited effects in those areas.

One of the most significant environmental aspects of the hearing was Syncrude's application for conceptional approval for its reclamation plans. Information was provided on Syncrude's plans for lease site reclamation and, to a greater extent, for fine tails reclamation. Fine tails materials, a "gel-like mixture of clays, minerals, bitumen and water,"[59] is formed as a by-product of Syncrude's hot water bitumen extraction process. The fine tails consolidate to a limited extent after several years of undisturbed settling and therefore large storage areas for the material are required. Syncrude proposed a new technique to place mature fine tails into the mined-out pit and cap it with fresh water, thus forming a fresh-water lake. Syncrude discussed other fine tails management alternatives being explored.

Syncrude also addressed the socio-economic effects of its project on local aboriginal communities and the City of Fort McMurray. Syncrude highlighted numerous initiatives and co-operative agreements between Syncrude and the surrounding communities. Syncrude expressed a commitment to meet the spirit and intent of the current draft accord between it and the Athabasca Native Development Corporation ("ANDC"), an association of First Nation and Métis locals in the region. The present Syncrude/ANDC accord had not been signed as at the date of the hearing. Syncrude committed itself to implement the concerns addressed in the draft accord, regardless of whether it was later executed.

(C) Positions of the Intervenors

All of the environmental intervenors opposed the production increase applied for by Syncrude. They argued that the public interest would not be served by permitting the cumulative increase of atmospheric emissions above current predicted levels. Syncrude's application to permit imports of bitumen was opposed on the basis that no evidence was supplied to the ERCB on bitumen sources, volumes or destinations nor of possible impacts on public safety and local infrastructure.

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[59] *Ibid.* at 15.

Considerable information was put forward by the environmental intervenors about the environmental effects of atmospheric emissions that would stem from increased production. The intervenors focused not only on the estimates of predicted emissions, but on Syncrude's ability to implement emission reductions, the extent of sulphur deposition from emissions, the vegetative effects of emissions, the ambient air quality and the effects on the physical health of the surrounding population. The intervenors argued generally that the ERCB should seriously review levels of pollution emissions previously allowed in light of Canada's national and international commitments to reducing greenhouse gas emissions. The environmental intervenors argued that extensive and detailed scientific data was not available to gauge properly sulphur deposition levels, vegetative effects, ambient air and health impacts. Thus, the ERCB was encouraged to exercise its discretion not to grant the expansion proposal at this stage. Alternatively, the environmental intervenors requested that any expansion permit be subject to conditions including implementation of extensive environmental monitoring mechanisms, funding and implementation of environmental and health studies and positive obligations to reduce and mitigate environmental impacts of the plant production increase.

Socio-economic issues addressed by Fort McKay and ATC included the effect of land disturbance on traditional aboriginal activities and on animal populations growth on traditional lands, and compensation issues resulting from use of land traditionally claimed by aboriginal groups. Fort McKay and ATC encouraged the ERCB to impose conditions on Syncrude to ensure the socio-economic concerns of the native communities were met.

(D) The ERCB's Decision

The ERCB accepted Syncrude's scientific studies regarding atmospheric emissions and the extent of related environmental effects. The ERCB did express concerns with regard to the level of ongoing environmental monitoring, the need for continued research into environmentally beneficial mitigation measures and the need for the implementation of such measures to reduce emission limits and the environmental effects of land use and bitumen processing. Syncrude was permitted to increase its current production limit subject to maintaining atmospheric emissions below existing limits, to pursuing further emission reduction measures and to developing ambient air quality, sulphur deposition and bio-monitoring programs. The term of the overall Syncrude project was extended as requested and Syncrude's request to import bitumen was approved. Further, the conceptional mining, lease development and reclamation plans were approved subject to Syncrude developing the water-capped lake technique in the base mine lake project and to continuing research into alternative reclamation and fine tails management techniques. The ERCB indicated that Syncrude had taken considerable measures to mitigate against detrimental socio-economic effects, particularly in respect of the native communities, and determined that negative social impacts associated with local native communities were not attributable to Syncrude's operations.

ii. *Amoco Canada Petroleum Company Limited — Whaleback Well Licence Application*[60]

(A) Introduction

Amoco Canada Petroleum Company Ltd. ("Amoco") had applied to the ERCB for a licence to drill an exploratory well in the Whaleback Ridge area of the Eastern Slopes region of southwestern Alberta. As the application was of concern to a large number of interested parties, the ERCB convened a public hearing to address the application and the related concerns, which included potential wildlife and environmental impacts of the well, and various related land-use issues.

The ERCB denied the application of Amoco to drill the proposed exploratory well. In so doing, the ERCB identified and addressed seven primary issues:

(1) information requirements;
(2) need for the exploratory well;
(3) location of the exploratory well;
(4) potential future development;
(5) public health, safety and quality of life;
(6) public consultation; and
(7) land use.

(B) Information Requirements

With respect to the information requirements of Amoco, the ERCB found that Amoco "generally attempted to meet the intent of IL 93-9"[61] and, as such, the information was adequate to proceed to a hearing on the matter. Notably, the ERCB focused the present discussion on the nature of the information requirements as set out in IL 93-9, a document which outlines the general information expectations of the ERCB for oil and gas proposals in the southern portion of the Eastern Slopes region. The ERCB stated that IL 93-9 was developed solely as a guide to the range of information that applicants should consider in preparing their applications. The level of information appropriate in each different case is "a function of the nature of the proposed development and of the relative environmental sensitivity of the area proposed to be developed."[62] Ultimately, however, the onus rests with the individual applicants to discern and to address fully all of the relevant issues to the application, particularly those of concern to residents in the vicinity of the proposed well.

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[60] *In the Matter of an Application for an Exploratory Well Licence; Porcupine Hills-Whaleback Ridge Area; Amoco Canada Petroleum Company Ltd* (September 1994), No. D 94-8 (E.R.C.B.).

[61] *Ibid.* at 10.

[62] *Ibid.*

(C) Need for the Well

The ERCB was clear in its support of Amoco's position that, provided that all public interest tests could be met, there would be a definite need for an exploratory well in order for Amoco to evaluate the seismic prospect, obtain geologic information and determine the potential for future development, from which development "substantial economic benefit could flow."[63] In this case, however, Amoco did not provide any technical evidence to support its predictions of the probability of encountering hydrocarbons or the potential size of the reserves. Thus, the potential economic value of eventual development was unknown, and therefore could not be weighed against the relevant public interest concerns particular to this case. In the course of this discussion, the ERCB did not accept Amoco's argument that the acquisition of mineral rights or a surface lease automatically confers the right of an applicant to a well licence.

(D) Location of the Well

In respect of its reasons for the selection of the particular surface location for the proposed well, Amoco did not present any supporting data, nor any data with respect to alternate locations. "[T]he Board would prefer, in this case, to be convinced that the applied-for location is the optimum site. Prior to approving the ... site, the Board would expect Amoco to address and support the rationale of site selection and possible options in more detail."[64] As a result, the ERCB found that Amoco had not adequately demonstrated the need to locate the well at the proposed location.

(E) Potential Development Options

Amoco presented three potential future development options, only one of which it advocated as a preferred development plan, assuming the well was ultimately approved and successful. Its preferred option involved extended-reach drilling technology to permit the drilling of four wells per pad from approximately five pads. "Considering both technological advances and the lack of precedent, the Board considers Amoco's future vision to be, at best, at the outer bounds of current technology available in Alberta."[65] The ERCB also noted the reasonable probability that, if the well were successful, more well pads would be required than Amoco's development plan currently contemplated.

(F) Health, Safety and Quality of Life

With respect to the issues of public health, safety and quality of life, the ERCB supported Amoco's drilling program, as designed, as one which "represents a reasonable effort"[66] to reduce the concerns of the area residents regarding health and safety. The ERCB discussed in some detail various elements of this aspect of the

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[63] *Ibid.* at 12.
[64] *Ibid.* at 14.
[65] *Ibid.* at 16.
[66] *Ibid.* at 23.

application, including Amoco's proposed measures relating to drilling activity, blowout prevention, emergency response, emissions and contaminants. The ERCB believed that the proposed well could be drilled in a safe and efficient manner, consistent with all currently applicable ERCB regulations.

(G) Public Consultation

Notable with respect to the public consultation process was the emphasis placed by the ERCB on Amoco's "poor start" therein, and the resultant lack of trust in Amoco by the area residents affected by the proposed exploratory well.

> Amoco must accept much of the responsibility for this lack of trust. It is clear that many of the area residents were left unaware of the scope of Amoco's plans for the area until the late stages of the licensing process. The first contact did not occur until after surface access had been established and after Amoco had applied for a licence from the ERCB to drill the well.[67]

Despite Amoco's subsequent initiatives to outline its proposed project to area residents, the ERCB held that a "renewed effort" in communication between Amoco and area residents was necessary to deal with many of the issues at hand.

(H) Land Use

Of primary interest to many in the energy community is the ERCB's unprecedented discussion and resolution of the land use issues and related environmental issues brought to the forefront largely by the myriad of intervenors in Amoco's application. The ERCB framed the issue as follows: whether the proposed development could be carried out in a manner which would not reduce the existing land-use values so significantly that the overall public interest is compromised. In resolving this issue, the ERCB gave much credence to the land-use management guidelines set out by Alberta Forestry in the Livingstone-Porcupine Hills Sub-Regional Integrated Resource Plan (the "IRP"), despite the non-binding nature of these guidelines. The applicable resources management guideline governing mineral development near the proposed well location states:

> Development of mineral resources will be permitted in the Whaleback Ridge Critical Wildlife Zone where it can be demonstrated that there is no net loss of wildlife habitat, disruption of wildlife populations and loss of ecological and extensive recreation values found within this area.[68]

Initially, Amoco had argued that the tests set out in the IRP only applied to the proposed project during the development stage, and not the exploratory stage. The ERCB rejected this argument, and stated that "it would not be reasonable to prevent development activity which resulted in either habitat loss or loss of ecological values

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67 *Ibid.* at 27.

68 Alberta Forestry, Lands and Wildlife, *Livingstone — Porcupine Hills Sub-Regional Integrated Resource Plan* (Edmonton, 1987) at 101.

but allow exploratory activity which had the same effect."[69] As such, the ERCB applied the tests to the proposed exploratory well, and found that the requirement of the IRP could not be met with the applied-for well location and routing of the access road. In particular, the ERCB found that the road extension contemplated by Amoco would be "totally inconsistent with the intent of the IRP,"[70] causing at least a modest loss of functional wildlife habitat as a result of its construction, the resultant permanent increase in public access to the area and the operation of the drilling site itself.

Also affecting the ERCB's decision was the presence of the Special Places 2000 program, a government environmental initiative which is designed to protect certain ecologically unique areas in Alberta. The ERCB acknowledged that the Whaleback area would likely be a prime candidate for consideration by the Special Places 2000 program, and that "allowing oil and gas development in the Whaleback region prior to allowing the Special Places 2000 program to run its course would likely compromise its relative value to the program."[71] Thus, the ERCB deferred to the broader provincial context of the environmental program, as "it would [not] be in the public interest for it to approve an application for energy development that may, in turn, significantly compromise a scarce or unique combination of ecological values."[72]

(I) Implications of this Decision

As mentioned the ERCB, as a result of its consideration of the seven primary issues, denied Amoco's application to drill the proposed exploratory well. The two determining factors in the ERCB's denial of the application may be seen as: first, the applicant's lack of concrete, technical data with respect to well need and well location; and second, the environmental and land use peculiarities of the Whaleback region. It is important to note that the ERCB expressly endorsed the economic need for the continued exploration and development of Alberta's natural gas resources, and may well have granted the application had it not been "deficient" in its supporting information. Additionally, although it may be cited as a precedent in future ERCB hearings concerning proposed development in environmentally sensitive areas, the Whaleback decision is specific to the facts surrounding ecosystem integrity in the Whaleback area, and the precise tests set forth in the relevant IRP. The environmental and land use peculiarities, in combination with the deficient evidence of the applicant, ultimately resulted in the ERCB's denial of the well licence in this case.

iii. *Petro-Canada Application for a Coalbed Methane Project*[73]

Petro-Canada applied to the ERCB for a Coalbed Methane Project in the Battle Lake area. The ERCB considered the issues with respect to the application to be: (1) need

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[69] *Supra* note 60 at 33.

[70] *Ibid.*

[71] *Ibid.* at 34.

[72] *Ibid.*

[73] *Petro-Canada Application for a Coalbed Methane Project, Battle Lake Area* (February 1995), No. D 95-2 (E.R.C.B.).

for the project; (2) impact of the project; and (3) public consultation. The ERCB approved the application subject to certain monitoring and reporting conditions.

(A) Need for the Project

The ERCB normally views the ownership of mineral rights as a basic element in the establishment of the need for a project. The ERCB expressed the general principle that the operation of market forces will generate appropriate commercial decisions about the timing of the development. The fact that conventional gas reserves are in ample supply at a particular time does not mean that there is no need for individual companies to assess resource development to support their commercial obligations and strategies.

The ERCB found that there was a public need for more information about coal-seam natural gas and its potential as a source for future supply. The ERCB considers coalbed methane to hold significant potential as a future gas resource for Alberta. In order to assess the commercial viability of coalbed methane development, actual production and operational data is required. The ERCB said this project would be valuable in assessing the viability of coalbed methane development. The need for the project, however, must be weighed against the resulting impacts.

(B) Project Impacts

Although the ERCB did not believe that the environment in the vicinity of the project was "pristine," it recognized the continuing natural character of that environment and the interests of local residents in maintaining that character. Numerous environmental issues were addressed at the hearing, including the matters discussed below.

The local community expressed concerns about the potential for excessive noise. The ERCB accepted Petro-Canada's evidence that noise from the proposed project would meet the ERCB's noise guideline — Interim Directive ID 94-4, "Noise Control Directive." Petro-Canada made a commitment to achieve sound levels from the compressor that would be lower than the requirements of ID 94-4. The ERCB indicated that the guidelines set out in ID 94-4 are appropriate for the proposed project.

Truck traffic for waste water disposal was a concern to the community. The ERCB said that an evaluation of produced water handling options that could eliminate the need to truck large volumes of water should be conducted as early as possible.

A very significant environmental issue was spill prevention and groundwater protection. Witnesses for Petro-Canada and the intervenors expressed differing views as to the level of natural protection from a salt water spill. Petro-Canada asserted that the formation from which drinking water was produced was protected by overlying clay till. The ERCB concluded that, given Petro-Canada's planned protective measures, a spill would be unlikely, and in the event a spill occurred, it would be remedied quickly with little chance of contaminating ground water.

The intervenors also raised additional matters, including the following: the possibility of H_2S gas migration into project wellbores, wellbore casing corrosion, the possibility of naturally occurring radioactive materials ("NORM") being present in produced fluids, and large scale coal seam dewatering leading to surface subsidence. The ERCB dismissed the concern about H_2S migration. It also considered the risk of casing corrosion to be unlikely in the area. The ERCB said that it was inappropriate to use insubstantive data concerning NORM from one geological setting in one area to suggest that NORM would exist in the project area. The ERCB found intervenor evidence concerning potential surface subsidence to be very weak.

(C) Public Consultation

The ERCB endorsed ongoing communication between Petro-Canada and area residents from project conception to abandonment. The ERCB noted that early disclosure was necessary to ensure that the community and the proponent have a good understanding of all of the potential impacts and issues, and what mitigative measures may be necessary.

(D) Land Use Matters

The ERCB made some interesting comments on this point which bear upon matters such as cumulative impacts and the balancing of those impacts against economic benefits. The ERCB noted that numerous diverse activities, including significant oil and gas development, have been occurring in the Battle Lake area for many years. The ERCB said that one of the issues was at what point has there been enough oil and gas development in the area. It went on to identify the essential question: when will the level of development become so intrusive and damaging to the residents and the environment that it is no longer in the public interest to allow it to go on? The ERCB said that many factors must be considered: what damage is being done; is it mitigable to any extent; what parts of it are irreversible; the duration; and the specific factors of each situation. The ERCB found that although at some point development will exhaust the economic resource, the value of existing infrastructure must bear on the ERCB's decision until that time. Delayed or fragmented development reduces the economic value of the resource in the ground because, in part, associated infrastructure is taken out of service and isolated pockets are more costly to develop.

iv. *Unocal Canada Management Limited's Sour Gas Plant*[74]

(A) Introduction

The public hearing resulting in this decision was called by the ERCB pursuant to s. 42 of the *Energy Resources Conservation Act* in response to an objection received from the Lubicon Lake Indian Nation ("Lubicons") with respect to the ERCB's earlier approval of a sour gas processing plant since constructed by Unocal Canada

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[74] *Unocal Canada Management Limited Proceeding Regarding an Approved Sour Gas Plant, Slave Field (Lubicon Lake Area)* (February 1995), No. D 95-4 (E.R.C.B.).

Management Limited ("Unocal"). In their objection, the Lubicons indicated that they had not been fully informed as to the nature of the sour gas plant at the time of giving their agreement not to oppose the original approval, and now had additional concerns in regards to safety, health, the environment and general social well-being as a result of the plant's construction near the Lubicon reserve lands.

The ERCB upheld its original approval with respect to the construction and operation of the sour gas processing plant by Unocal. The plant, in the ERCB's opinion, could be operated in a safe manner, without substantive risk to the people living in the area, namely the Lubicons.

In setting out reasons for its decision, the ERCB identified and considered three issues: (1) rights with respect to energy development; (2) public consultation; and (3) plant review.

(B) Rights with Respect to Energy Development

In considering rights with respect to energy development, the ERCB focused on two matters: its jurisdiction over the matter at hand; and its practice of notification of energy resource developments in certain defined areas. With respect to its jurisdiction, the ERCB commented that it did not have jurisdiction over issues of native land claims, nor did it have jurisdiction over mineral and surface access leases on public lands, whether in Alberta or Canada. Its jurisdiction, which stems from various Alberta statutes, is limited to the regulation of energy resource development, and clearly includes full authority to deal with an application for the approval of the construction of a sour gas processing plant.

(C) Public Consultation

Because of uncertainty surrounding the identification of future Lubicon reserve lands, in 1986 the ERCB delineated an area of 2300 square kilometres within which it expected applicants would notify the Lubicons of any energy proposal requiring ERCB approval. Although it did not expect the applicant to obtain the consent of the Lubicons for its proposal, it did expect the applicant to provide full details of the project to the Lubicons. Since the original delineation, however, the Alberta government and the Lubicons have signed the Grimshaw Accord, which clearly identifies certain areas in which reserve lands are to be adopted. As a result, the ERCB, in the present application, discontinued the formal notification process adopted in 1986, and accepted, instead, a more routine public consultation process with respect to proposed projects affecting the Lubicons.

The issue which continues to spark debate about the ultimate approval to the subject sour gas processing plant is the public consultation process which took place between Unocal and the Lubicons. In the words of the ERCB, "[t]he primary issue was whether the Lubicons were fully aware of the technical, environmental, and other impacts of the Unocal project at the time that they responded to the proposal. Their response was a

letter to Unocal ... indicating they would not oppose the project."[75] Whereas Unocal maintained that there had been extensive communication between itself and the Lubicons, as a result of which no outstanding concerns about the plant were evident, the Lubicons, on the other hand, insisted that at no time were they made aware that the plant was in fact a sour gas plant, and that they perceived the project to encompass an expansion to an existing sweet gas plant and other facilities. The ERCB concluded that, given the opposing evidence of the parties, there had been a "misunderstanding" in the discussions of the project prior to plant approval, as a result of which, the Lubicons were not able to give an "informed consent" to the project. In the opinion of the ERCB, however, this lack of "informed consent" alone did not enable the Lubicons to prevent the plant from being developed. "The Board believes that this hearing has provided the Lubicons an opportunity to receive clear details of the project and identify their concerns; thus allowing the Board to examine these concerns, weigh the evidence provided, and apply the test of public interest in retrospect."[76]

(D) Plant Review

Lastly, the ERCB undertook a review of the evidence in respect of the operation of the plant itself, and determined, as it had in the original approval, that the sour gas processing plant was in the public interest having regard to the need for the plant, and the social, economic and environmental effects of the plant. Notably, in considering many individual factors, such as, for example, plant emissions, human health, wildlife and safety, the ERCB was faced with documented, technical evidence in support of Unocal's arguments therein, but received no concrete evidence from either the Lubicons or the intervenors on behalf of the Lubicons to support their arguments that the plant posed a risk to the surrounding environment. It thus concluded, based on the evidence before it, that "the Unocal gas plant meets or exceeds all reasonable public interest tests applied to such facilities."[77]

(E) Observation

Perhaps the most interesting part about the Unocal decision is the amount of public and political debate generated thereby, which is ongoing. During the hearing itself, the Lubicons received significant support from diverse groups opposing the plant on a number of grounds, the most popular of which were the issues of land claims and the survival of the Lubicons' traditional culture. The ERCB avoided a debate on these issues it its forum, based on its lack of jurisdiction over such matters.

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75 *Ibid.* at 16.
76 *Ibid.* at 18.
77 *Ibid.* at 28.

v. *CanStates and Atcor Applications for Gas Removal Permits*[78]

(A) Introduction

CanStates Gas Marketing ("CanStates") and Atcor Ltd. ("Atcor") applied to the ERCB pursuant to the *Gas Resources Preservation Act* ("*GRPA*") for permits to remove gas from Alberta. Objections to the applications were filed by several intervenors and a public hearing was requested. The ERCB convened a pre-hearing meeting to seek the views of interested parties on issues raised by the intervenors. The ERCB asked parties to make submissions on the following questions:

> (1) How does section 2.1 of the *Energy Resources Conservation Act* ("*ERCA*") govern the Board in exercising its jurisdiction under the *GRPA*?
>
> (2) Should the ERCB reconsider environmental and social matters considered at the time oil and gas facilities are licensed, when assessing gas removal applications under the *GRPA*?
>
> (3) Given the framework of policy under which applications to remove gas from Alberta are considered, what elements of the public interest should guide the ERCB in considering specific applications?[79]

Following the pre-hearing meeting, the intervenors withdrew their request for a hearing. The ERCB thereafter issued its Memorandum of Decision for the pre-hearing meeting in which it stated its view concerning the arguments presented, and decided that it would issue the applied-for permits.

(B) Arguments of the Intervenors

The main arguments of the environmental intervenors included the following:

(1) section 2.1 of the *ERCA* created a positive obligation on the ERCB to broadly consider environmental and social implications during its review of gas removal applications;
(2) the gas removal permit process involved sufficient activities so as to make it a proposed energy resource project subject to a broad environmental review under s. 2.1 of the *ERCA*;
(3) a cumulative environmental review was most appropriately conducted at the gas removal permit stage and would not be duplicative because prior environmental assessments of upstream facilities inadequately reviewed cumulative environmental and social effects; and
(4) the public interest factors generally set out and followed by the ERCB in ERCB Report 87-A: *Gas Supply and Protection for Alberta* inadequately addressed the environmental and social impacts of gas removal from Alberta.

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[78] *CanStates Gas Marketing and Atcor Ltd. Gas Removal Permit* (April 1995), (Memorandum of Decision — Applications No. 941191 and No. 941214).

[79] *Ibid.*

(C) Arguments of the Applicants and Industry Participants

The submissions of CanStates, Atcor and industry participants can generally be summarized as follows:

(1) there are no physical implications to the environment by virtue of the ERCB granting a gas removal permit and thus an environmental review was inappropriate;
(2) section 2.1 of the *ERCA* did not materially affect the ERCB's jurisdiction in assessing public interest considerations for gas removal permits and thus the ERCB was not obligated to vary from its past practice;
(3) extensive environmental review for a gas removal permit would be unnecessary duplication of the upstream facilities environmental assessments previously conducted by the ERCB; and
(4) a cumulative environmental review by the ERCB during gas removal applications would be prejudicial to participants relying on the ERCB's regulatory decisions respecting upstream facilities.

(D) Decision of the ERCB

In its decision, the ERCB stated:

> More specifically, the Board was being asked to consider under this issue whether Section 2.1 of the ERCA [the *Energy Resources and Conservation Act*] applies to gas removal permit applications and if it does, how should the environmental, social, and economic effects of gas removal be addressed. Another issue raised by the parties is whether the subject applications are complete or additional information is needed for the Board to make its determination.[80]

After reviewing the arguments of the parties, the ERCB determined that s. 2.1 of the *ERCA* effectively codified the ERCB's past practice and jurisdiction of broadly considering the public interest during the course of granting regulatory approval for gas removal permits. Public interest considerations in the form of cumulative environmental, social or economic impacts were both adequately addressed and more appropriately addressed during the course of the ERCB's review of facilities permit applications. Reconsideration of those public interest factors would be extremely prejudicial to parties relying on previous ERCB determinations and who would have little or no opportunity to participate in gas removal permit applications.

The ERCB confirmed that the public interest factors reviewed during gas removal applications were adequately and appropriately set out in ERCB Report 87-A. Those factors were the present and future supply of gas in Alberta, the established reserves, trends and growth in discovery of gas reserves and generally other related matters the ERCB considered appropriate to each particular application. The ERCB did not fetter its discretion by weighing each gas removal application against the factors and procedures established by ERCB Report 87-A.

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80 *Ibid.* at 5.

(E) Leave to Appeal

In response to the ERCB's decision, the intervenors filed an application with the Alberta Court of Appeal for leave to appeal. Leave has been granted and the appeal is expected to be heard in the fall of 1995.

2. Public Utilities Board (now the Alberta Energy and Utilities Board)

a. Decisions

i. *Canadian Hunter Application to Fix Rates for Peace Pipe Line*[81]

(A) Introduction

Canadian Hunter Exploration Ltd., Crestar Energy, PanCanadian Petroleum Limited and Rigel Oil & Gas Ltd. ("Applicants") applied, pursuant to s. 101 of the *Public Utilities Board Act*, that the PUB fix just and reasonable rates, tolls and charges for service on the Peace Pipe Line Ltd. ("Peace") pipeline system and, pursuant to s. 52(2) of the *Act*, that the PUB establish as interim the rates, tolls and charges for service provided on the Peace pipeline system. The bases of the application were that the tolls and tariffs charged by Peace were excessive and discriminatory among shippers on the Peace pipeline system.

The PUB dismissed the application, finding that it was neither just nor reasonable to implement regulated rates and tolls for services on the Peace pipeline system in view of the competitive climate in which such service is provided.

Once the PUB determined that it had jurisdiction over the application in question, it pronounced its decision almost cursorily, citing the competitive Alberta market as its primary reason for not determining applicable rates and tolls on the Peace pipeline system. It was the determination of whether or not the PUB had jurisdiction over the application, however, which constituted the majority of the efforts of the Applicants, the intervenors and the PUB in this matter.

(B) Jurisdiction

Concerning the issue of jurisdiction, Peace took the position that because the methodology for determining the rates for service on the Peace pipeline system is set out by legally-binding contracts, the PUB has no jurisdiction to render an order, pursuant to s. 101 of the *Act*, that would interfere with and impose regulation upon such contracts, which were freely-negotiated, arm's length contracts. Peace also argued that there is no precedent for the PUB to apply s. 101 to regulate the rates of any oil pipeline in Alberta, nor for the PUB to consider Peace as a public utility and thus to

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[81] *In the Matter of an Application by Canadian Hunter Exploration Ltd., Crestar Energy, PanCanadian Petroleum Limited and Rigel Oil & Gas Ltd. re: Peace Pipe Line Ltd.* (August 1994), No. E94047 (P.U.B.).

regulate it accordingly. These arguments were supported in part by Chevron Canada Resources Limited ("Chevron") and the Alberta Energy Company Ltd. ("AEC"). Home Oil Company Limited ("Home Oil") argued that it was necessary that Peace be declared a common carrier by the ERCB prior to the PUB having jurisdiction to set the rates and tolls of Peace.

The Applicants, necessarily, submitted that s. 101 gives the PUB jurisdiction to set just and reasonable rates on an oil pipeline, which is not a public utility, and that Peace itself has, in previous proceedings, recognized this jurisdiction. Implicit in the power of the PUB to set just and reasonable tolls is the jurisdiction of the PUB to override contractual pricing provisions. Both the Alberta Petroleum Marketing Commission ("APMC") and WesCana Energy Marketing Inc. endorsed the submissions of the Applicants.

(C) Interim Rates

With respect to the issue of interim rates requested by the Applicants pursuant to s. 52(2) of the *Act*, Peace argued that the PUB does not have jurisdiction to grant interim rates. Should the PUB find that it has jurisdiction, however, Peace submitted that the Applicants nevertheless failed to discharge their onus to demonstrate that there was compelling evidence for the PUB to exercise its discretion to award interim rates. Peace identified three fundamental threshold issues which were not addressed by the Applicants, namely: (1) whether there is a need to regulate the operations of Peace; (2) whether it is appropriate to commence first-time regulation of an entity that has been unregulated for thirty-five years based on a three-day interim hearing, and (3) in considering whether interim rates should be granted, it should be recognized that the Applicants represent two of Peace's thirty-one shippers, and two producers out of hundreds, whereas all other shippers and producers as well as Peace would be affected by the decision.

Not only did the Applicants fail to provide evidence to establish the need for interim rates, Peace argued, neither did they tender any evidence to establish that the existing rates were unreasonable. Peace concluded with the submission that if its rates were to be established by the PUB, it would effectively be precluded from responding adequately to competitive market forces.

A number of intervenors argued on record with respect to the issue of interim rates. The APMC supported the position of the Applicants; however, Unocal Canada Limited, Chevron and Home Oil did not, essentially citing the resultant regulation of rates as their primary objection thereto.

(D) The PUB's Decision on Jurisdiction

In an unprecedented decision, the PUB decided that, pursuant to s. 101 of the *Act*, it had the proper jurisdiction to fix just and reasonable rates and tolls for an oil pipeline, even if in doing so, it would thus override the provisions of existing contracts between the pipeline company and its customers.

In outlining its reasons for decision, the PUB addressed, and almost simultaneously rejected, a number of submissions made by Peace with respect to the question of jurisdiction (not all of which will be discussed herein). On the matter of the necessary status of the Peace pipeline system as a common carrier, the PUB held that s. 101 of the *Act*, which gives jurisdiction to fix rates, *etc.* with respect to oil pipelines, "is not limited to pipelines, the proprietor of which has been declared by the ERCB to be a common carrier,"[82] and which thereby fall within the definition of a "public utility" under the *Act*. Thus, "[t]he Board's jurisdiction [under s. 101] includes 'any oil pipeline.'"[83]

The PUB also discussed at some length a number of judicial decisions which were presented by the parties, dealing with the power of the PUB to override existing contractual provisions when fixing rates, *etc.* under authorizing legislation. Such cases referred to differing versions of the jurisdiction provisions similar to the current s. 101. The PUB analogized section 101 with s. 23(c) of the 1915 *Act*, whereby the PUB was given the power to fix "just and reasonable individual rates ... whenever the board shall determine any existing individual rate ... to be unjust, unreasonable, insufficient or unjustly discriminatory or preferential,"[84] and with s. 23(a) following the 1921 amendment to the *Act*, which provided in part for the PUB's power "to fix and determine a reasonable price or prices at which natural gas shall be sold." Notably, both provisions, like s. 101, were silent as to the issue of overriding existing contractual provisions.

The analysis of the PUB was as follows: in *Re The Public Utilities Act; Northern Alberta Natural Gas Development Company, Limited* v. *City of Edmonton*,[85] the Court considered s. 23(c) of the 1915 *Act* not to include the [implicit] power to override contracts "because of the particular statutory context, in which it was present."[86] That is, apart from s. 23(c), the statute at that time specifically gave the PUB the power to interfere with unreasonable contracts by lowering rates under s. 20(b), whereas under s. 20(g), the statute specifically made the power to increase rates subject to any existing contracts. By contrast, the Court in *Lethbridge* v. *Canadian Western Natural Gas, Light, Heat & Power Company Limited*[87] held that s. 23(a) included the [implicit] power to override contracts, as, at that time, there were no other provisions in the statute setting out conditions under which the PUB may override contracts. In the opinion of the PUB, the current s. 101 finds itself in a similar statutory context as s. 23(c), discussed in the *City of Lethbridge* case as "[t]here are no other provisions in the PUB Act which deal specifically with oil pipelines."[88] As a result, "section 101, though silent about contracts, like section 23(a), implies a power to override contracts,

[82] *Ibid.* at 39.
[83] *Ibid.* at 40.
[84] *The Public Utilities Act*, S.A. 1915, c. 6, s. 23(c).
[85] (1919), 15 Alta. L.R. 416 (S.C. App. Div.).
[86] *Supra* note 81 at 53.
[87] [1923] 1 W.W.R. 838 (Alta. S.C.A.D.).
[88] *Supra* note 81 at 54.

where it is necessary to do so, to fix rates, tolls and charges, which are just and reasonable."[89]

(E) The PUB's Decision on Setting Rates

Having determined that it had jurisdiction in this matter, the PUB went on to deny perfunctorily the application to set such rates. With respect to the issue of setting rates, the PUB simply commented that "[t]he legislation does not set out specific instruction to the Board with respect to how or when such rates should by fixed other than the requirement that they be 'just and reasonable.'"[90]

(F) Observations

In the result, the lengthy debate regarding jurisdiction was almost a moot point for the purposes of this application, as it was then so quickly dismissed for reasons of "competitive climate." However, the Peace pipeline decision does stand as an important precedent whereby the PUB has expanded its understanding of its own jurisdiction over oil pipelines.

(G) Review and Appeal Proceedings

The Applicants commenced an application to the PUB for a review and variance of its decision, and filed an application with the Alberta Court of Appeal for leave to appeal the PUB's decision. In response to the Applicants' leave to appeal application, Peace also filed a leave to appeal application. The PUB convened a hearing on January 24, 1995 to hear the arguments of the parties on the review and variance application. No decision has been rendered. The leave applications have been adjourned pending the PUB's review disposition.

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89 *Ibid.*

90 *Ibid.* at 55-56.