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

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This article reviews numerous recent decisions of the National Energy Board, the Alberta Energy and Utilities Board, the British Columbia Utilities Commission and the Manitoba Public Utilities Board pertaining to oil and gas issues. In addition, changes in the national and provincial statutory frameworks governing the oil and gas industry are explored. While the emphasis throughout the article is placed on developments federally and in Alberta, significant decisions and legislative changes in other jurisdictions within Canada are also highlighted.

Le présent article examine de nombreuses décisions récentes émanant de l'Office national de l'énergie, de l'Alberta Energy and Utilities Board, de la British Columbia Utilities Commission et de la Régie des services publics du Manitoba sur des questions relatives à l'industrie du pétrole et du gaz. Il étudie également les changements survenus dans les cadres législatifs nationaux et provinciaux régissant ces secteurs. Bien que l'accent porte sur les faits nouveaux survenus à l'échelle fédérale et en Alberta, des décisions et des modifications importantes émanant d'autres régions du Canada sont également prises en compte.

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I. INTRODUCTION

The purpose of this article is to highlight and discuss regulatory and legislative developments during the period May 1997 through April 1998 which are of particular interest to oil and gas lawyers. With respect to regulatory developments, the article primarily examines decisions of the National Energy Board ("NEB") and the Alberta Energy and Utilities Board ("AEUB"), although noteworthy decisions of other regulatory bodies such as the British Columbia Utilities Commission ("BCUC") and the Manitoba Public Utilities Board ("MPUB") are also examined. Additionally, the article details certain key regulatory and policy developments at the NEB and the AEUB. With respect to legislative developments, particular emphasis is placed on Alberta and federal legislative developments, although notable developments in other jurisdictions are also discussed.

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II. REGULATORY DEVELOPMENTS

A. FEDERAL

1. NATIONAL ENERGY BOARD

a. Decisions

(i) GH-6-96: Sable Off-Shore Energy Project and Maritimes & Northeast Pipeline Project[1]

This is a companion decision to the Joint Public Review Panel Report discussed later in this article. The NEB (also, the "Board") decision contains a chapter drawn directly from the Joint Review Panel Report which recounts the recommendation in favour of the Sable Off-Shore Energy Project ("SOEP"). The NEB decision then deals with the areas over which the NEB has jurisdiction. Dealing first with the SOEP, the Board concludes that it would be favourable from a socio-economic point of view and unlikely to cause significant adverse environmental effects. While satisfaction was expressed with the facilities design and configuration, SOEP will be required to file details of the final design prior to construction.

On economic matters, the Board briefly discusses supply and markets, tolling and financing, before concluding that SOEP facilities can be financed and will be used and useful over their economic life.

With respect to tolling and method of regulation, SOEP had suggested that it would be the sole user of the off-shore pipeline transportation and on-shore gas processing facilities and that, accordingly, it would not be charging a toll for either service. Therefore, SOEP concluded that there was no basis for NEB regulation. However, SOEP also suggested in the alternative that it should be regulated by the NEB on a complaints basis as a Group 2 company, a designation reserved, with a couple of significant exceptions, for smaller pipelines with only a handful of shippers. The Board opted in favour of the latter proposal.

The next chapter of the Board's decision deals with the on-shore pipeline facilities proposed by Maritimes & Northeast Pipeline Project ("M&NE") commencing at the outlet of the gas processing plant at Goldboro, proceeding through Nova Scotia into New Brunswick and, for the NEB's purposes, terminating at the New Brunswick border with Maine. The project is a major one, consisting of 558 kilometres of pipeline with a diameter of 762 millimetres (30 inches). As with SOEP, favourable findings are made with respect to environmental, socio-economic, engineering and economic matters.

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[1] NEB, *In the Matter of an Application of Sable Off-Shore Energy Project for Facilities and Tolls and Maritimes & Northeast Pipeline Project for Facilities and Tolls*, No. GH-6-96 (December 1997) [hereinafter "GH-6-96"].

proposed by PNGTS paralleled the oil line. It was argued by Union that commercial considerations on the United States' side of the border caused the shift and Canadian tollpayers should not have to pay for it. While Union was not opposed, *per se*, to the route to East Hereford, it argued that the costs borne by Canadian tollpayers should be limited to those involved in extra construction. As noted, its initial view in evidence was that the lowest cost option would be a route from Sabrevois to Highwater. In argument, it agreed that a Lachenaie to Highwater route would be a reasonable point of comparison for cost and tolling purposes.

For its part, TQM, together with TCPL and PNGTS, advanced testimony that PNGTS had moved its original import point from Highwater to East Hereford not only for marketing reasons, but also for considerations related to the environment, construction practices and regulatory concerns with the State of Vermont.

The Board rejected the Union proposal and applied the reasoning that an earlier NEB panel had applied to the Blackhorse Extension in the Niagara Falls area.[4] It found that the PNGTS extension would be integrated with the rest of the TCPL system (including TQM) and that the service to be provided on the facilities would be the same as that provided on the balance of the TCPL system. The routing surcharge proposal of Union was rejected because of the simple finding that there were no proposals to construct corresponding take-away capacity on the United States' side from Highwater.

Lastly, the Board found that a pressure surcharge should be an element of the tolls charged by TQM for East Hereford deliveries. It did so on the basis that the delivery pressure at East Hereford is in excess of the minimum tariff pressure specified in TQM's tariff. Such a practice is consistent with the practice on TCPL's system.

(iii) GH-2-97: TransCanada PipeLines Limited Facilities[5]

Notwithstanding its higher numerical designation, this hearing took place prior to TQM's proceedings in GH-1-97 described above. TCPL's hearing occurred in September and October of 1997 and resulted in a decision released on December 8, 1997. TCPL's application was for various facilities over its entire system comprising approximately 308 kilometres of pipeline loop plus new compressors, metering facilities and other facilities, all estimated to cost $825 million.

These facilities were strongly related to the TQM application in that 44 percent of firm volumes to be moved on TCPL were destined for markets to be served by the PNGTS Extension. Some of the same issues debated at the TQM GH-1-97 proceeding described above had been debated earlier at the TCPL facilities hearing.

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4 NEB, *In the Matter of an Application of TransCanada PipeLines Limited for the Blackhorse Extension*, No. GH-R-1-92 (June 1992).

5 NEB, *In the Matter of an Application of TransCanada PipeLines Limited for 1998 Facilities*, No. GH-2-97 (November 1997).

(vi) MH-2-97: Application by Novagas Canada Ltd. for an inquiry into the practices of Westcoast Energy Inc. with respect to gas stripping arrangements at Taylor, British Columbia[10]

On May 12, 1997, Novagas Canada Ltd. ("NCL") filed an application on its own behalf, and on behalf of certain shippers asking for an inquiry into certain practices of Westcoast Energy Inc. ("Westcoast") at Taylor, British Columbia. The fact situation involved is somewhat complicated.

In 1985, Westcoast and Petro-Canada had formed a joint venture to construct a natural gas liquids stripping plant at Taylor in order to recover natural gas liquids ("NGL") other than ethane from the residue gas stream of Westcoast's McMahon plant.

Westcoast, as processor of gas at the McMahon plant, agreed to make gas available to the joint venture pursuant to a gas stripping agreement dated May 1, 1986. In return for the liquids, the joint venture agreed to re-deliver a thermally equivalent volume of pipeline-quality gas. At the time of the 1986 gas stripping agreement, Westcoast was party to an arrangement with the British Columbia Petroleum Corporation ("BCPC"), whereby Westcoast owned all the natural gas in its system. This situation changed soon thereafter and Westcoast, in common with other federally regulated pipelines, became more a transporter of gas to the point that, by 1995, it owned little or no gas that it was shipping in its system other than its line pack. In 1990, BCPC was privatized and acquired by CanWest Gas Supply Inc. ("CanWest").

In 1995, the joint venturers sold the NGL plant to Solex Developments Company Inc. Ultimately, ownership of the plant went to a trust, but Solex Gas Liquids Ltd. (together with Solex Developments Company Inc., "Solex") continued to operate the plant. At the time of the sale to Solex, Westcoast entered into a 1995 gas stripping agreement ("GSA") which replaced the May 1, 1986 agreement. The GSA provides that Westcoast will make available to Solex up to 420 million cubic feet of gas a day from the McMahon plant to permit Solex to strip the liquids. As under the previous arrangement, Solex provides shrinkage gas on a thermally equivalent basis.

In 1996, Solex obtained approval from the Province of British Columbia to expand its plant. However, NCL also obtained provincial approval to build a gas stripping plant which would obtain feedstock from the McMahon plant residue stream. The Solex plant and the NCL plant were competing for the remaining residue gas from McMahon not being processed by the existing plant. In addition, NCL had other sources of residue gas upon which it proposed to draw.

NCL was concerned that some of the gas volumes it contracted for its plant might be diverted to the Solex plant by virtue of the GSA. It questioned whether Westcoast had the right to divert gas in such circumstances, particularly since Westcoast no longer

[10] NEB, *In the Matter of an Application of Novagas Canada Ltd. requesting that the Board inquire into the Practices of Westcoast Energy Inc. with Respect to Gas Stripping Arrangements at Taylor, British Columbia*, No. MH-2-97 (October 1997).

The Board also dealt with matters of emergency response preparedness and route deviations based on environmental concerns.

A discussion of note took place on right-of-way agreements with affected landowners. The Board was concerned that paragraph 86(2)(e) of the *National Energy Board Act* was not being adequately addressed in Amoco's right-of-way agreement. The subsection reads:

> 86(2) A company may not acquire lands for a pipeline under a land acquisition agreement unless the agreement includes provision for
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> ...
>
> (e) restricting the use of the lands to the line of pipe or other facility for which the lands are, by the agreement, specified to be required unless the owner of the lands consents to any proposed additional use at the time of the proposed additional use;[12]

Amoco's right-of-way agreement provided that any additional pipe installation beyond the original one would require Amoco to pay to the owner a sum of money as agreed to between the parties. Amoco argued that any landowner consenting to further compensation must necessarily have agreed to the additional use, notwithstanding the absence of the specific wording in its agreement. It cited authorities for this proposition.

The argument failed because the Board found that Amoco has the right to negotiate or arbitrate compensation even though consent may not necessarily have been obtained. It required more specific wording in Amoco's contract notwithstanding its awareness that such a step would require the re-opening of right-of-way negotiations with all landowners along the 155 kilometres of the route.

(viii) OH-2-97: Interprovincial Pipe Line Inc. Line 9 Reversal[13]

This hearing was heard at various times through August and September of 1997 following an application by IPL dated May 1, 1997. The Board issued a decision generally approving the application on December 18, 1997.

IPL's Line 9 extends from Sarnia, Ontario to Montreal, Quebec and was built at the behest of the Government of Canada in reaction to the Arab oil embargo of 1973. After its construction, Line 9 flowed western Canadian crude oil to refineries in Quebec, but, over the years, its usefulness declined to the point that its use east of a point near Hamilton, Ontario was suspended. The reversal application was the result of an interest on the part of various Ontario refiners to obtain more favourably priced feedstock from offshore, particularly the North Sea. A more complete history is contained in the written decision.

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

13 NEB, *In the Matter of an Application of United Refining Company for Designation of a Priority Destination on Interprovincial Pipe Line Limited*, No. OH-2-97 (18 December 1997).

agreement had been reached whereby the tolls would be fully integrated with the rest of the IPL system for a time, with a gradual transition to fully stand-alone tolls. The Board accepted the proposal, taking the position that this could give parties an adjustment period for any changes in oil markets possibly resulting from the reversal.

The Government of Quebec raised the concern of supply deficiency in the future in Quebec and possible re-reversal. Although IPL could re-reverse in six weeks under normal conditions and two weeks in an emergency, Quebec still sought the installation of storage facilities for Montreal refineries to deal with a possible emergency situation. However, Quebec tendered no evidence in support of any of its proposals and they were rejected by the Board.

Another matter considered in the hearing was an application by United Refining Company ("United") for priority destination designation. United has a refinery in Warren, Pennsylvania which is connected by pipeline to Chippawa, Ontario and IPL's system. IPL connects to Chippawa via Line 9 and proposed, upon reversal of Line 9, to switch to Line 7. United was concerned that Line 7 might be full on occasion and that, given the situation being imposed on it against its will, it should have a priority designation, meaning that it would not be subject to apportionment but would obtain its full nomination in the event Line 7 capacity were to be apportioned. Priority destinations had been provided for in an earlier decision by the Board when it had changed the system of allocation on IPL.[15]

The Board denied the United application, expressing confidence that IPL would optimize the use of its system and stating its expectation that parties could work out matters without the need for its intervention. However, it went on to encourage United to bring forward an application at a future time should the Board's expectation not come to pass.

(ix) RH-1-97: TransCanada PipeLines Limited 1997 Tolls and FST Conversion Proposal[16]

Pursuant to its incentive settlement with its shippers, TCPL applied for certain approvals and for conversion of its firm service tendered service ("FST"). The Board approved an overall cost-of-service of slightly in excess of $1.7 billion and a rate base of $7.4 billion for the 1997 test year. The rate-of-return on common equity was set at 10.67 percent, 58 basis points lower than in 1996. The common equity ratio was continued at 30 percent.

FST is an annual service which enables TCPL to fill in valleys in its transport volumes by tendering excess capacity on a daily basis. Because of the frequently

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[15] NEB, *In the Matter of a Public Inquiry under subsection 20(3) and Part IV of the National Energy Board Act into Matters Relating to the Interprovincial Pipeline Apportionment of Pipeline Space*, No. MH-3-85 (July 1985).

[16] NEB, *In the Matter of an Application of TransCanada PipeLines Limited for Tolls and Approval of TransCanada's FST Conversion Proposal*, No. RH-1-97 (September 1997).

capacity can be contracted for three- and five-year terms. A bidding process will be introduced for interruptible tolls.

Since that part of its business is becoming more competitive in Westcoast's traditional service area of northeast British Columbia, the intent is that Westcoast's gathering and processing operation be able to react accordingly so that, by the end of 2001, all tolls will be market-based, freely negotiated and subject only to complaint-type regulation by the Board. The settlement reflects the fact that considerable negotiation is still necessary in order to put the gathering and processing settlement in place.

While acknowledging that there are a number of outstanding matters, the Board found that the tolls in the settlement and the method for determining tolls are just and reasonable for the years 1997 to 2001 and approved them.

In 1994 and 1995, Westcoast incurred costs with respect to two expansion projects which did not proceed. One was in connection with the McMahon plant and gathering in the Fort St. John basin behind that facility. The other was for the construction of a processing plant in the Grizzly Valley, at Tumbler Ridge. Westcoast applied to recover costs incurred of $42.18 million in the case of Fort St. John, and $18.53 million in the case of Grizzly Valley.

The Board found that Westcoast's costs for pursuing the Fort St. John expansion to the point of preparing the application and taking it through the hearing process were reasonable. However, it denied costs related to procurement of materials prior to Board approval. In its view, there were warning signs that should have indicated to Westcoast that Board approval would not be automatic. The Board stated that Westcoast accepted the risk by continuing to order equipment late in 1994 and early 1995. Accordingly, the Board approved $26.03 million in costs but $23.01 million was disallowed as well as $3.02 million in allowance for funds used during construction.

Grizzly Valley was treated somewhat differently and more harshly from the point of view of Westcoast and certain producers. From an early date, uncertainty had surrounded this proposal. It was caught up in a jurisdictional challenge and shipper interest was limited. Ultimately, Westcoast discontinued the project. Prior to that, because of the uncertainties surrounding the project, the Grizzly Valley shippers had agreed to backstop 75 percent of Westcoast's project-related costs which the NEB did not permit Westcoast to recover in its cost of service.

The Board noted that Westcoast was concerned enough about its risks to require the backstopping of the shippers and that it withdrew the application before it had even gone to hearing. It therefore denied all of the project development costs associated with Grizzly Valley in the amount of $18.53 million.

(iv) Assessment of Unconnected Reserves[23]

The EUB and the NEB released the results of Phase II of their review of unconnected gas reserves in Alberta in June 1997. As a result of this review, the EUB/NEB common gas reserves database has been reduced by 6 percent to 88.2 billion cubic metres. Phase III of the review, which will include pools discovered between 1978 and 1987, began in July 1997. As well, the NEB reviewed unconnected reserves in British Columbia and concluded that they should also be reduced.

(v) Common Reserves Database

In December 1997 the NEB and the British Columbia Ministry of Employment and Investment ("MEI") signed a reserves database agreement under which the two parties have agreed to use a common oil and gas database and to develop and use efficient methods for estimating reserves. The agreement is confined to estimates of reserves, related reservoir parameters and geological analysis for natural gas and crude oil pools. The parties also intend to implement joint pool reserves or province-wide studies when required.

In order to harmonize the different methods of estimating reserves, the Board and MEI have agreed to set up a Joint Technical Steering Group whose mandate will include recommending and directing a program of special studies and monitoring the implications of alternative reserves definitions.

(vi) EUB Report — *Natural Gas Assessment: Producers' Response to Changing Market Conditions —1992-1996*[24]

The Board released a report entitled *Producers' Response to Changing Market Conditions — 1992-1996* on June 25, 1997. The report looks at the response of producers in the Western Canadian Sedimentary Basin to the changing market conditions from 1992 to 1996. Examined in the report are:

- the level of gas-directed activity within the producing sector;
- underlying supply characteristics which have a bearing on producers' efforts to maintain and expand gas supply; and
- the development of methods to calculate estimates of gas reserves and productive capacity additions.

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[23] Alberta Energy and Utilities Board, General Bulletin GB97-6, "Results of Unconnected Gas Review 96-1" (11 June 1997).

[24] National Energy Board, Report, "Natural Gas Assessment: Producers' Response to Changing Market Conditions — 1992-1996" (25 June 1997).

arguments regarding procedural fairness and the United States *Ashbacker* doctrine,[27] the panel rejected the request of TQM, Seafloor and Tatham that it delay issuance of its report in order to conduct a comparative review of the alternatives to the M&NPP. The decision of the panel was that it had satisfied its obligation to consider obligations to the M&NPP by considering evidence submitted during the hearing with respect to alternatives.

Much of the argument concerning "alternatives" arose out of the requirement found in paragraph 16(1)(e) of the *CEAA*[28] that an environmental assessment or review consider "alternatives to the project." The panel rejected the argument that such alternatives must be functionally different methods of developing and transporting Sable gas. Rather, the panel stated that an alternative was any proposal which incorporated any feasible method for the transportation of Sable gas. The panel also stated that an alternative, for the purpose of conducting an assessment under *CEAA*, included the option of not developing the resource at all at the present time.

The panel considered a number of potential adverse environmental effects with respect to the offshore environment and the SOEP. The World Wildlife Fund was particularly concerned with the effects of offshore development on an area known as "the Gulley." Concerns were also expressed regarding the discharge of drilling fluids and cuttings, the effect of ice scouring and the re-suspension of sediment due to blasting activities near the pipeline landfall. A number of interveners called for a zero-discharge policy with respect to drilling muds and cuttings, but this was rejected by the panel. The panel was concerned about the lack of baseline data regarding possible adverse effects on the aquaculture and recommended a minimum of one year of baseline monitoring. The panel also recommended that Country Harbour not be used as a base site.

The panel also considered socio-economic impacts of the projects. A number of parties questioned the adequacy of the Proponents' public consultation. The panel agreed that there had been inadequate initial contact with the aboriginal community, but stated that otherwise the public consultation program was extensive and it was satisfied with its overall effectiveness.

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27 This doctrine arises out of the United States Supreme Court decision of *Ashbacker Radio Corporation* v. *Federal Communications Commission*, 326 U.S. 327 (1945). In that case, two applicants applied for a broadcast license from the Federal Communications Commission ("FCC") to transmit on the same frequency. The FCC approved the first application without a hearing, but after the second application had been filed. On appeal, the Supreme Court noted that the applications were for a facility which could only be granted to one applicant. The Court ruled at 330:

> We do not think it is enough to say that the power of the Commission to issue a license on a finding of public interest, convenience or necessity supports its grant of one of two mutually exclusive applications without a hearing of the other. For if the grant of one effectively precludes the other, the statutory right to a hearing which Congress has accorded applicants before denial of their applications becomes an empty thing.

The Supreme Court continued to state that this principle only applied where there were two *bona fide* applications which were mutually exclusive.

28 *Supra* note 3.

After the close of the evidentiary portion of the hearing, the governing party of Nova Scotia had a change of leadership. During the reply argument, which was held after the change, the Province of Nova Scotia stated it was withdrawing its support from the Joint Position.

The panel's recommendation favoured the Joint Position, notwithstanding the withdrawal of support by Nova Scotia and the lack of support from NSP. The panel stated it believed the Joint Position offered the best overall package and that the discounts given to Nova Scotia and New Brunswick recognize Nova Scotia's argument that distance should be a factor in toll design.

B. PROVINCIAL

1. ALBERTA ENERGY AND UTILITIES BOARD

a. Board Decisions

(i) 97-06: Novagas Clearinghouse Fractionation Facility and Pipelines in the Redwater/Fort Saskatchewan Area[30]

This application was one of a series made by Novagas Clearinghouse Ltd. (now Novagas Canada Ltd., ("NCL")) to put an NGL gathering and processing system in place from northwestern Alberta and northeastern B.C.

The hearing, which lasted a day, was contested as existing processors in the Fort Saskatchewan area questioned the need for the facilities. NCL asserted there was a need and, for that reason, it had acquired an existing storage facility at Redwater, just north of Fort Saskatchewan, which it proposed it to turn into a fractionation facility as well. Pipelines would connect from there to the Fort Saskatchewan complex. The EUB (also, the "Board") expressed satisfaction that a need exists for additional fractionation capacity as well as for the interconnecting pipelines.

Some intervenors questioned what commercial arrangements would be in place. NCL stated that market forces would be the largest determinant of such arrangements. The Board appeared satisfied this will be the case since it merely acknowledged the concerns of intervenors without issuing any order. Satisfaction was also expressed with the technical and environmental specifications for the project.

30 EUB, *In the Matter of an Application of Novagas Clearinghouse Ltd. to Construct and Operate a Fractionation and High and Low Pressure Pipelines in the Redwater to Fort Saskatchewan Area*, No. 97-06 (15 May 1997).

(iv) 97-12: Novagas Canada Ltd. — Application to Construct and Operate a Sweet Gas Processing Facility and Associated Pipelines in the Parkland Northeast Area[33]

This decision is of note on the issue of plant proliferation. NCL entered into an arrangement to process gas on behalf of Mobil Oil Canada ("Mobil"). It had applied for a processing plant at East Porcupine together with an extensive gathering system of several hundred kilometres. That proposal, since abandoned, had been set back by local opposition and the attendant regulatory delay. Meanwhile, Mobil was anxious to commence production from two wells in the Mosquito Creek/Parkland area.

Interventions dealt with at the hearing were from Canadian Hunter Exploration Ltd. ("CHEL") and Ranger Oil Limited ("Ranger"), both of whom were owners of the existing Parkland plant. They contended that NCL, which applied for and received approval to build a plant five kilometres from the existing Parkland plant, did not give adequate notification to existing participants in the area. The hearing lasted for four days in July of 1997.

NCL, appearing with Mobil, asserted that no viable processing option had presented itself. Both NCL and particularly Mobil had been in discussions with the owners of the Parkland plant but had been unable to obtain satisfactory processing arrangements. Other arrangements had been sought in the area by Mobil as well.

The Board granted a temporary permit to NCL to process the gas in question pending the outcome of the East Porcupine application. However, it expressed disappointment in the efforts of both sides in dealing with the intent of the proliferation guidelines which are contained in the Board's Guide 56.[34] The Board also found that the actions of both sides had led to a hearing which might not have been necessary and that a partially constructed pipeline had resulted which, but for the Board's approval, would have had to be dealt with.

The Board found that there was a need for processing in the area, particularly because Mobil's wells were being drained, a point on which there was no dispute. There was also no dispute on the need to process the area gas. Ranger and CHEL argued that the Parkland plant could have been expanded. The Board stated that, had there been evidence of valid local landowner objection or significant environmental impacts, it might not have approved Mosquito Creek. Absent such concerns, it did.

This case is interesting in that it appears to stand for the proposition that a greenfields processing plant, even near an existing plant, will be justifiable and allowed

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33 EUB, *In the Matter of an Application of Novagas Canada Ltd. to construct and operate a Sweet Gas Processing Facility and Associated Pipelines in the Parkland Northeast Area*, No. 97-12 (26 August 1997).

34 EUB, Guide 56: *Energy Development Application Guide and Schedules* (April 1996). This guide has since been updated and reissued.

As with other developments in the Fort Saskatchewan area, the project was questioned by local intervenors on several environmental and socio-economic grounds. The Board found the design of the facility to be acceptable to meet these concerns.

(vii) 98-02: Numac Energy Inc. to Amend Approval No. 7936 for Reduced Spacing in the Wolf Lake and Bonnyville Sectors[37]

Numac Energy Inc. ("Numac") sought a reduction in the drilling spacing unit from 64 hectares to 4 hectares over slightly more than fifty sections of land. It was vigorously opposed by local landowners. The Board determined that the project was necessary to increase recovery and was technically viable and also approved the design.

There was opposition on environmental grounds to such items as increased trucking, twenty-four hour operations, noise and air quality. However, the chief concern was the public consultation program and whether it was adequate. The Board reviewed what was done and found that Numac could have been more flexible prior to the hearing. It nevertheless approved the project.

(viii) 98-03: Shell Chemicals Canada Ltd. — New Ethylene Glycols Plant, Fort Saskatchewan[38]

This is yet another industrial proposal for the Fort Saskatchewan area requiring large volumes of ethylene (250 kilotonnes) and natural gas (87.8 million cubic metres) per annum. As with other industrial proposals for the Fort Saskatchewan area, the Board found the proposal to be in the public interest but reviewed, yet again, the land use conflict concerns of local residents. Once again, it urged all parties to work to resolve their problems.

(ix) 98-04: Wild Rose Pipeline Inc. — Application to Construct and Operate the Athabasca Pipeline Project from Fort McMurray to Hardisty[39]

This preliminary decision was only issued on April 17, 1998 and detailed reasons have yet to be published at the time of writing. The Board approved the 550-kilometre, 762-millimetre diameter pipeline to transport high vapour pressure products and crude oil. Wild Rose Pipeline Inc. is a wholly owned subsidiary of IPL which struck an arrangement with Suncor Inc., which previously had advanced a competing proposal.

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37 EUB, *In the Matter of an Application of Numac Energy Inc. to Amend Approval No. 7936 for Reduced Spacing in the Wolf Lake and Bonnyville Sectors*, No. 98-02 (29 January 1998) [hereinafter "Decision 98-02"].

38 EUB, *In the Matter of an Application of Shell Chemicals Canada Ltd. for a New Ethylene Glycols Plant in the Fort Saskatchewan Area*, No. 98-03 (3 March 1998).

39 EUB, *In the Matter of an Application of Wild Rose Pipeline Inc. to Construct and Operate the Athabasca Pipeline Project from Fort McMurray to Hardisty*, No. 98-04 (17 April 1998).

meet the landowner concerns. Public consultation concerns were again raised and again the Board noted the communication breakdown. The application was allowed.

(xiii) 98-09: Shell Canada Limited — Application for a Well License, Quirk Creek Field[44]

Shell proposed drilling a sour gas well in Kananaskis Country near land owned by Square Butte Ranches Ltd. ("Square Butte"). The proposed well site would be 1100 metres from the northwest corner of the Square Butte lands. The Board concluded that the location was optimal in the circumstances and that access management as proposed by Shell was satisfactory. On environmental matters, the Board concluded that Shell's report did not meet the standards contained in the Board's information letter IL-93-09.[45]

The Board granted Shell's application but applied eight conditions to be met by Shell.

(xiv) U97096 NOVA Gas Transmission Ltd. Load Retention Service[46]

This hearing lasted for approximately two weeks in June of 1997. The decision was released on November 14, 1997. NGTL filed an application for load retention service ("LRS") in response to a significant bypass threat posed by Palliser Pipeline ("Palliser") which had proposed a federally regulated system running parallel to the NGTL eastern Alberta mainline to the Alberta border with Saskatchewan at Burstall (with a number of laterals, including a Medicine Hat lateral) and carrying approximately 1.2 billion cubic feet a day of gas.

NGTL and its parent entered into negotiations with "PanCanadian," one of Palliser's principals. A memorandum of understanding was reached whereby Palliser would suspend its application to the NEB and NGTL would make this application. Palliser could proceed if the LRS was not agreed to prior to November 30, 1997. However, approval of the LRS would mean Palliser would be wound up.

After initially rejecting the idea that the entire postage stamp design on NGTL should be reviewed (NGTL has since proposed discarding it), the Board determined four criteria against which the LRS proposal could be assessed. These were as follows.

(1) *The load retention rate is required to respond to a credible bypass threat.* The Board found that Palliser was indeed a commercially viable proposal and that NGTL had submitted sufficient information to prove that. PanCanadian is a financially strong

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44 EUB, *In the Matter of an Application of Shell Canada Limited for a Well Licence in the Quirk Creek Field LSD 16-19-21-4W5M*, No. 98-09 (15 April 1998).

45 EUB, Informational Letter IL-93-09, "Oil and Gas Developments Eastern Slopes (Southern Portion)" (13 December 1993).

46 EUB, *In the Matter of an Application of NOVA Gas Transmission Ltd. Load Retention Service*, No. U97096 (14 November 1997).

b. Recommendations of EUB examiners

(i) EUB, Examiner Report 97-02, "Application by Crestar Energy Inc. for permits to increase the hydrogen sulphide concentration of an existing pipeline and construct a sour natural gas pipelines in the Vulcan area"[47]

Crestar Energy Inc. ("Crestar") agreed to increase the hydrogen sulphide ("H_2S") level of its Kirkcaldy pipeline in the Vulcan area from up to 0.5 percent H_2S to a level of up to 1.8 percent. It wanted to build five new gathering pipelines to tie into the Kirkcaldy pipeline which would carry the gas to Crestar's Vulcan gas plant.

While finding that there was a need for the production of the gas in question, the examiners were not satisfied with the integrity of the existing Kirkcaldy pipeline. Crestar had conducted a pressure test which had resulted in a failure. A few months later, a second failure had occurred. While the line passed a pressure test, the examiners indicated an ongoing concern about the integrity of the Kirkcaldy line for a number of reasons and concluded that Crestar's evaluation had not been thorough enough. Crestar's application was denied.

(ii) EUB, Examiner Report 97-04, "Applications for a well licence and a pipeline permit Renaissance Energy Ltd., Provost field"[48]

Renaissance Energy Ltd. ("Renaissance") applied for a well and an associated pipeline which was resisted by the affected landowner. While two of the three examiners recommended that Renaissance be licensed for both the well and the pipeline, the minority examiner disagreed. There were concerns expressed about alkali production and considerable concern about the lack of preparedness of the applicant for the hearing and the dissemination of wrong information and confusing evidence.

(iii) EUB, Examiner Report 97-06, Enron Oil Canada Ltd. common carrier, common processor, allocation of production, Wapiti area[49]

Enron Oil Canada Ltd. ("Enron") applied for a common carrier and common processor order against Imperial Oil Resources. As well, it sought allocation of gas production between wells pursuant to paragraphs 37(4)(b) and 42(5)(a) of the *Oil and Gas Conservation Act*.[50] It was resisted by Imperial, CHEL and Amoco. Imperial, as operator, had advised Enron throughout discussions that there were capacity limitations that would affect Enron's ability to produce.

For a variety of reasons, Enron's application was denied. The examiners were not satisfied that inequitable drainage was occurring except in a few isolated periods or that

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47 4 June 1997.
48 24 June 1997.
49 23 September 1997.
50 R.S.A. 1980, c. O-5.

(ii) Guide 56[53]

The EUB issued a new version of Guide 56,[54] dealing with energy development applications. This revised Guide 56[55] also replaced Guide 33, which dealt with well licence applications.[56] The Board also changed the procedure for publishing notices of applications.

(iii) Publication of Notices

Since November 10, 1997 the Board has published all notices in newspapers and has billed the applicants. Applicants are no longer responsible for publishing notices.[57]

(iv) Benzene Emissions

The EUB adopted the *Best Management Practices for the Control of Benzene Emissions from Glycol Dehydrators* ("BMP").[58] The Board has directed all operators to implement whatever changes may be necessary to meet the goals and principles of the BMP. The key provision of the BMP requires the lowering of benzene emissions from glycol dehydrators to five tonnes per year per dehydrator by January 1, 2001 (three tonnes if the dehydrator is within 0.75 kilometres of a residence). Additionally, all dehydrators commissioned between January 1, 1999 and January 1, 2001 must be designed and operated to emit no more than three tonnes of benzene per year.

(v) Sour Well Licensing and Drilling Requirements

Early in 1998, the EUB amended its sour well licensing and drilling requirements.[59] The minimum setback requirements were amended, as were the requirements related to emergency response plans.

(vi) Application Fees and Utilities Division Restructuring

The EUB eliminated all application fees in 1998[60] and restructured the Utilities Division.[61]

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53 EUB, Guide 56: Energy Development Application Guide and Schedules, 2d ed. (October 1997) [hereinafter "Guide 56"].

54 *Ibid.*

55 *Ibid.*

56 EUB, Interim Directive ID-97-07, "Facility Applications — Well Licencing Requirements" (25 September 1997).

57 EUB, Informational Letter IL-97-03, "Changes to the EUB Legal Notice Process" (27 October 1997).

58 EUB, Informational Letter IL-97-04, "Emissions from Glycol Dehydrators" (17 November 1997).

59 EUB, Interim Directive ID-97-06, "Sour Well Licensing and Drilling Requirements" (13 February 1998).

60 EUB, General Bulletin GB-98-3, "Elimination of Application Fees" (26 March 1998).

61 EUB, General Bulletin GB-98-4, "The Alberta Energy and Utilities Board Restructures Utilities Division" (3 April 1998).

(2) a proposal by Northwest Pipeline Corporation ("Northwest") to expand its pipeline facilities along the Columbia River Gorge in Washington and thus move more volumes to British Columbia, either physically or by displacement;

(3) a proposal by Westcoast to expand its existing pipeline system from northeastern British Columbia to the lower mainland;

(4) a liquified natural gas ("LNG") proposal as an alternative to the SCP, by B.C. Gas for somewhere on the lower mainland to augment its present LNG facility at Tilbury Island;

(5) a proposal by Pacific Gas Transmission Company ("PGT") (now PG&E Gas Transmission — Northwest) to construct an LNG facility at Cherry Point, Washington to connect to B.C. Gas' system in the Fraser Valley;

(6) a proposal by Westcoast Gas Services Inc. ("WGSI") to construct an LNG facility near Squamish; and

(7) a proposal by Williams International Pipeline Company ("Williams") to construct an LNG facility at Sumas, Washington, at the point where Westcoast's pipeline joins up with the facilities of Northwest on the international border.

Pursuant to BCUC requirements, the proposals were judged according to B.C. Gas' integrated resource plan ("IRP") and run through a resource optimization model ("ROM").

Differences at the hearing revolved around the assumptions contained in the ROM, which B.C. Gas found favoured the SCP. In addition, there were significant differences regarding whether B.C. Gas needed a base load or a peaking load facility.

The decision is a long one, running to 111 pages. Generally, the BCUC found that the demand for both peak and seasonal demand advanced by B.C. Gas was reasonable. It also found that a good many of the assumptions in the ROM were reasonable, but it did change the nominal discount rate employed as well as the assumptions of third party revenue generated by the SCP and came out with a very different, and lower, result.

The BCUC found that three sets of resource options were superior to the SCP alone. These were the LNG option, the Northwest expansion option and the southern crossing in conjunction with the Westcoast and Northwest expansion option.

In the result, the BCUC denied B.C. Gas' request and required that it examine improving base load requirements by entering into discussions with British Columbia Hydro for a co-generation facility. It also required B.C. Gas to take a closer look at the LNG option, particularly if the discussions with B.C. Hydro failed to bear fruit by October of 1998.

not allowed. Assets are to be transferred from the regulated entity to affiliates only with prior acknowledgement from the PUB which normally expects such transactions to take place at fair market value. Further restrictions on the ability of Centra and its unregulated affiliates to share facilities, executives, staff and boards of directors were set out.

At the hearing, the matter of a common name was debated at some length, particularly the issue of who owned the name "Centra" and what right, if any, the PUB had to control the use of the name. The PUB stated a preference that Centra not share a common name with affiliates but said it would not prevent it because "no evidence was presented that conclusively proved the use of a common name would significantly impede competitors from participating the Manitoba natural gas market or other related services."[68]

In early 1997, Centra sought a review of the PUB decision by the PUB and subsequently sought, unsuccessfully, to appeal the decision to the Manitoba Court of Appeal.

The second part of the decision, issued in February of 1998, discusses impediments to competition under the present marketing regime and concludes that several changes should be made to make gas prices more transparent to the average customer. While seeking to remove these impediments, the order emanating from the decision permits Centra to remain as a natural gas supplier on a regulated basis but with only one regulated price supply option. Centra will continue to be the party providing storage, related transportation and load balance for all participants selling into the Manitoba market. Further, Centra will be responsible for nominations on gas being transported to Manitoba and continue to provide backstopping. Centra's bill is to be redesigned to show the various components making up the price of gas, namely commodity, transportation, storage and distribution.

III. LEGISLATIVE DEVELOPMENTS

A. FEDERAL

1. *NATIONAL ENERGY BOARD ACT*[69]

Division III of Part VI of the *National Energy Board Act* was amended by the *Canada-Chile Free Trade Implementation Act*[70] to include references to the Canada-Chile Free Trade Agreement (the "CCFTA"). Part VI deals with free trade agreements.

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68 Order 110/96 at 25.

69 *Supra* note 12.

70 S.C. 1997, c. 14 (in force 5 July 1997).

tank systems includes the age of the system, as well as details concerning its construction, leak detection and corrosion protection systems.

B. PROVINCIAL

1. ALBERTA

a. *Environmental Protection and Enhancement Act*[76]

The *EPEA* was amended by Bill 33, the *Environmental Protection and Enhancement Amendment Act, 1998*[77] which was assented to April 30, 1998. The majority of the amendments are minor and of a housekeeping nature. For example, the definitions of "quarry" and "well" were reworked and department names were corrected.

Paragraph 35(f) of the *EPEA* was amended to allow cabinet to make regulations authorizing a delegated authority to make by-laws under the *Act*. A new section was added to deal with the priority of government's costs and another was added to deal with the registration of designations and orders against land.

b. *Mines and Minerals Act*[78]

The *Mines and Minerals Amendment Act 1997*,[79] assented to on May 29, 1997, amended the *Mines and Minerals Act* in a fairly substantial manner, including the repeal of a number of sections. For example, certain definitions, such as that of "spacing unit" and "unit operation" were repealed. The section defining, for the purpose of agreements, the size of sections, quarter sections and legal subdivisions was repealed, as were the sections dealing with execution, surrender, transfer, division and consolidation of agreements and the interests dealt with by agreements. The primary provision dealing with agreements, section 20, was replaced. Section 30.1, dealing with the appointment of representatives in respect of agreements, was added, along with regulations dealing with agreements (discussed below).

Perhaps the most significant amendment is the replacement of sections 90 to 99, dealing with leases and licences, with new sections 90 to 93. Gone are the provisions dealing with the rights granted under a lease or licence. The new sections are much more brief. They deal with the term of leases and provide that at expiry, a lease or licence continues only to the extent it is approved for continuation by the Minister. The 120-day window prior to the expiry of a lease for obtaining a continuation has been abolished. As well, the provisions which formerly described, in great detail, the requirements for continuation applications and the considerations for granting continuations, have all been repealed.

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76 S.A. 1992, c. E-13.3 [hereinafter *EPEA*].

77 S.A. 1998, c. 15.

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

79 S.A. 1997, c. 17.

(iv) *Mines and Minerals Administration Regulation*[89]

The *Mines and Minerals Administration Regulation* came into force on January 1, 1998. Among the matters dealt with in this regulation are the mechanism for complying with section 30.1 of the *Mines and Minerals Act.*[90] This section requires that where an agreement is held by two or more lessees, the lessees must designate a representative. The regulation also deals with certain procedural matters such as the giving of notices by and to the Minister, and the issuance of agreements under paragraph 16(a) of the *Mines and Minerals Act.* A schedule to the regulation sets out fees for certain services including those related to agreements.

(v) *Petroleum and Natural Gas Tenure Regulation*[91]

This regulation replaced the *Petroleum and Natural Gas Agreements Regulation,*[92] and it came into force on January 1, 1998. The *Petroleum and Natural Gas Tenure Regulation* again deals with agreements under the *Mines and Minerals Act.*[93] The regulations stipulate that, subject to any terms, conditions or exceptions in an agreement, an agreement conveys both the exclusive right to drill for and recover petroleum and natural gas in the location of the agreement in respect of which rights are granted by the agreement and the right to remove any recovered petroleum or natural gas. However, such agreements do not include the rights to any oil sands or coal bed methane in respect of which the holder of a coal lease has been granted rights.

Part 1 of the regulation deals with petroleum and natural gas licences. The initial terms of licences vary depending on location, but range from two to five years. The regulation also sets the maximum area of the location of a licence. Part 2 deals with petroleum and natural gas leases. This part includes provisions regarding applications for continuation of leases and offset requirements. Part 3 of the regulation contains a number of general provisions including time extensions related to drilling problems.

(vi) *Crown Minerals Registration Regulation*[94]

The *Crown Minerals Registration Regulation* came into force on January 1, 1998. It deals with the registration of documents, including transfers, security notices and other statutory notices. It provides that the Minister will assign provisional registration numbers to documents received immediately upon receipt by the registration office of the department, but that if the Minister subsequently refuses to register the documents because of some deficiency, the provisional registration number is cancelled. If a document is ultimately registered, the date of registration is the date on which the

89 Alta. Reg. 262/97.
90 *Supra* note 78.
91 Alta. Reg. 263/97.
92 Alta. Reg. 188/85.
93 *Supra* note 78.
94 Alta. Reg. 264/97.

e. *Oil and Gas Conservation Act*[107]

(i) *Oil and Gas Conservation Regulations*[108]

A number of minor amendments to the *Oil and Gas Conservation Regulations* were made by the *Oil and Gas Conservation Amendment Regulations*,[109] largely to take account of the publication of Guide 56.[110] The EUB also took the opportunity to do some housekeeping. Several sections which required parties to provide notice to the EUB in respect of certain matters have been amended to provide that notice be given to other parties. For example, prior to the amendment of section 2.100, an applicant for a well licence had to provide notice to the EUB if the applicant intended to drill through a coal bed or seam. The amendment changed this to eliminate the notice to the EUB and require notice to the lessee of the coal lease.

Other amendments remove certain requirements in respect of construction of facilities. For example, section 9.030 was amended to eliminate the requirement that construction related to a new scheme (or a major modification to an existing scheme) for the processing of gas could not proceed until the required permits under the *Clean Air Act*[111] or the *Clean Water Act*[112] had been issued. However, the EUB must still approve the location, conservation levels and pollution control features.

f. *Pipeline Act*[113]

(i) *Pipeline Regulation*[114]

The *Pipeline Amendment Regulation*[115] was filed on January 21, 1998 amending the *Pipeline Regulation*. The sections dealing with an application for a permit to construct, for a licence to operate a pipeline, and applications to discontinue operation of or abandon a pipeline have been amended to refer specifically to the requirements of Guide 56.[116] Provisions regarding the surveying of right-of-way boundaries, and emergency shutdown devices have also been included as part of the amendments.

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[107] *Supra* note 50.
[108] Alta. Reg. 151/71.
[109] Alta. Reg. 11/98, Alta. Reg. 12/98, Alta. Reg. 13/98, Alta. Reg. 14/98 and Alta. Reg. 25/98.
[110] *Supra* note 34.
[111] R.S.A. 1980, c. 12, as rep. by *EPEA*, *supra* note 76, s. 247 (c).
[112] R.S.A. 1980, c. 13, as rep. by *EPEA*, *supra* note 76, s. 247(d).
[113] R.S.A. 1980, c. P-8.
[114] Alta. Reg. 122/87.
[115] Alta. Reg. 7/98.
[116] *Supra* note 76.

4. NOVA SCOTIA

a. *Gas Distribution Act*[127]

The prospect of gas delivered from Sable Island has ignited interest in the establishment of local distribution companies in Nova Scotia. The province proclaimed the *Gas Distribution Act* on September 3, 1997, repealing at the same time the *Gas Utilities Act*.[128] The purpose of the Act is to "provide a framework for the orderly development and operation of a gas delivery system" and to "allow for fair competition in the sale of gas for consumption."[129]

Under the *Act*, gas delivery systems may only be operated pursuant to a franchise, granted by the Nova Scotia Utility and Review Board ("NSURB") upon application. The Act sets out a number of factors the NSURB must consider, including the existence of markets, adequate supplies and the related experience of the applicant. Although the Act prohibits the NSURB from granting a franchise to a "public utility" as defined in the Nova Scotia *Public Utilities Act*,[130] a subsidiary or affiliate of a public utility may be granted a franchise.

The *Act* also allows parties to apply for a franchise within an existing franchise area. In such cases, the NSURB must satisfy itself that granting such a franchise will not impose an undue burden on the existing customers of the franchise holder and will not unduly affect the economic interests of the existing franchise holder. Franchise holders are prohibited from unduly discriminating against any person or locality in respect of rates, tolls, charges, service or facilities.

Under the *Act*, franchise holders must obtain a permit to construct and a licence to operate a gas delivery system. Both are issued by the NSURB under the *Pipeline Act*.[131] Franchise holders may not charge any tolls or charges not specified in a tariff which has been filed with and approved by the NSURB. Tolls are regulated on a complaints basis, and the NSURB may also fix just and reasonable tolls on its own initiative.

With respect to the sale of gas, the *Act* prohibits any sale without a licence issued by the NSURB. Again, no public utility may hold a licence for the sale of gas.

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127 S.N.S. 1997, c. 4.
128 R.S.N.S. 1989, c. 182.
129 *Ibid.*, s. 2.
130 R.S.N.S. 1989, c. 380.
131 R.S.N.S. 1989, c. 345.