

CANADA'S ROLE IN THE UNITED STATES' OIL AND GAS SUPPLY SECURITY: OIL SANDS, ARCTIC GAS, NAFTA, AND CANADIAN KYOTO PROTOCOL IMPACTS

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I. INTRODUCTION

Canada is the United States' largest foreign supplier of oil, natural gas, and electricity. This includes 15% of gross oil imports and 14% of the total natural gas supply.¹ Prospects for continuing and increasing these relatively secure energy supplies are strong in view of proposed major natural gas pipelines from the Arctic and continued development of Alberta's oil sands. The oil sands hold estimated reserves of 2.5 trillion barrels (bbls) with ultimate recoverable reserves of 315 billion bbls.²

However, there are several clouds on the horizon. One concern is the declining of the oil and natural gas reserves and production in the historically productive Western Canada Sedimentary Basin (WCSB). A second concern is the regulatory and financial burdens and overall economic effects that Canada's December 2002 ratification of the Kyoto Protocol on greenhouse gas emissions reduction will have on the petroleum industry in general, and on future oil sands development, in particular. Regulatory uncertainty and investment chill are already observable, and lengthy and uncertain constitutional litigation between energy-producer provinces and the federal government is a possibility.

A third concern is the potential cost and delay resulting from complex environmental regulation and the implications of aboriginal interests for the proposed Arctic natural gas pipelines. The final concern is the growing unease of the Canadian public about the long-term national energy supply in view of the

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1. NAT'L ENERGY POLICY DEV. GROUP, NATIONAL ENERGY POLICY: RELIABLE, AFFORDABLE, AND ENVIRONMENTALLY SOUND ENERGY FOR AMERICA'S FUTURE 8-4, 8-8 (May 2001), available at <http://www.whitehouse.gov/energy/National-Energy-Policy.pdf>. The United States Energy Information Administration data puts November 2003 crude oil imports from Canada at 1639 (thousand bbls per day), just behind Saudi Arabia's 1664. ENERGY INFO. ADMIN., OFFICE OF OIL & GAS, U.S. DEP'T OF ENERGY, PETROLEUM SUPPLY MONTHLY 9, 12 (July 2002), available at http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_supply_monthly/psm.htm.

2. ALTA. ENERGY AND UTIL. BD., STATISTICAL SERIES 2003-98, ALBERTA'S RESERVES 2002 AND SUPPLY/DEMAND OUTLOOK 2003-2012 (2003), available at <http://www.eub.gov.ab.ca/bbs/products/STs/st98-2003.pdf> [hereinafter EUB (2003)].

energy trade provisions of the North American Free Trade Agreement (NAFTA) and developing United States North American energy policies. These issues will be assessed. First however, Canada's oil and natural gas reserves, supply, and export potential will be reviewed. Attention will be given to the massive unconventional oil reserves represented by the bitumen deposits of the oil sands.

II. CANADIAN OIL AND GAS SUPPLY

A. Oil

The WCSB, located primarily in the province of Alberta, has been the principal source of conventional oil, i.e., light crude (density <900 Kg/m³) and heavy crude (density > 900 Kg/m³). Minor producing areas include Ontario, the Newfoundland Grand Banks, the Scotian Shelf, and the Northern Frontier region. Figure 1 shows the location of these producing areas and includes the location of oil sands deposits that are discussed below.³

In its 1999 report, *Canadian Energy: Supply and Demand to 2025*, the National Energy Board (NEB) estimated conventional crude oil resources "to be 34 billion cubic metres (m³) of original oil-in-place, of which about 9.2 billion m³ (27 percent) is estimated to be ultimately recoverable."⁴

B. Western Canada Sedimentary Basin

Eighty-two percent of the estimated 3.6 billion m³ of ultimately recoverable light crude reserves in the WCSB have been discovered, and of these, 23% remain as established reserves and future improved recovery reserves.⁵ Similarly, "[f]or conventional heavy oil, some 1.1 billion m³ (82 percent) of the estimated ultimate recoverable resources have been discovered, and of these discovered resources, 0.5 billion m³ (50 percent) remain in the established reserves and the future improved recovery [reserves]."⁶ This is clearly a portrait of a relatively mature production basin.

Remaining WCSB established reserves are in decline as shown by Figure 2.⁷ While the number of producing wells has increased, crude oil production has declined as shown by Figure 3.⁸

The Alberta Energy and Utilities Board (AEUB) has documented the decline in average well productivity. In 2001, approximately half of the oil wells produced less than 2 m³/day per well. These 16,100 wells operated at an average rate of 1 m³/day and produced only 13% of total Alberta crude oil.⁹

3. See *infra* p. 425.

4. NAT'L ENERGY BD., CANADIAN ENERGY: SUPPLY AND DEMAND TO 2025 61 (1999), available at http://www.neb-one.gc.ca/energy/supplydemand/1999/supplydemand1999_e.pdf [hereinafter NEB (1999)].

5. *Id.* at 62.

6. NEB (1999), *supra* note 3, at 62

7. See *infra* p. 426.

8. See *infra* p. 426.

9. ALTA. ENERGY AND UTIL. BD., STATISTICAL SERIES 2002-98, ALBERTA'S RESERVES 2001 AND SUPPLY/DEMAND OUTLOOK 2002-2011 3-17 (2002), available at <http://www.eub.gov.ab.ca/bbs/products/STs/st98-2002.pdf> [hereinafter EUB (2002)].

C. Arctic and East Coast Offshore Frontier Areas

By contrast, there is considerable reserve potential in the relatively unexplored frontier areas. Some 4.3 billion m³ of ultimate recoverable resources are estimated to exist in the Northern, Nova Scotia Offshore, and Newfoundland Grand Banks areas. Some 528 million m³ are estimated to be recoverable, while only 32 million m³ have been produced, mainly from the historic southern Mackenzie Valley region.¹⁰

D. Oil Sands

Canada's oil sands or crude bitumen reserves are located in northeastern Alberta (Figure 4).¹¹ The oil sands area of 4.3 million hectares is approximately the size of Scotland.

Bitumen is recovered either by surface mining, or in the case of deeper deposits, by in situ recovery. In situ recovery involves the heat from steam to reduce the viscosity of the bitumen allowing it to be separated from sand and pumped to the surface. To be transported in pipelines, bitumen crude must be diluted with a lighter viscosity substance, usually pentanes plus. Synthetic crude oil (SCO) is bitumen upgraded to density and viscosity similar to conventional light crude that may be used by refineries as feedstock.¹²

In late 2003, for the first time, the *Oil and Gas Journal* included oil sands reserves in its estimate of total proven Canadian crude oil reserves.¹³ This placed the Canadian total at 178.9 billion bbls, second only to Saudi Arabia and included 174.4 billion bbls of oil sands crude bitumen reserves based on AEUB calculations.¹⁴ This is by far the largest reserve of its kind and represents a major reserve by global standards comparable even to the proven conventional oil reserves of Saudi Arabian reserves (Figure 5).¹⁵

Oil sands production of bitumen and synthetic crude oil has steadily increased since its inception in the 1960s. In 2002, Alberta synthetic crude oil production was 161 million bbls.¹⁶ In 2001, total raw bitumen production exceeded Alberta conventional oil production for the first time. The AEUB forecasts that production of both crude bitumen and synthetic crude will increase significantly through 2011 (Figures 6¹⁷ and 7¹⁸).

Growth in non-upgraded bitumen and synthetic oil production will more than offset the decline in conventional crude oil production. By 2011, non-

10. NEB (1999), *supra* note 3, at 62.

11. *See infra* p. 427.

12. NAT'L ENERGY BD., CANADA'S OIL SANDS: A SUPPLY AND MARKET OUTLOOK TO 2015 4 (Oct. 2000) [hereinafter NEB (2000)].

13. Marilyn Radler, *Worldwide Reserves Grow: Oil Production Climbs in 2003*, 101 OIL & GAS J. at 43 (Dec. 22, 2003).

14. EUB (2003), *supra* note 2, at 2-1-2-4 (initial in-place reserves: 1631 billion bbls; initial established reserves: 178.3 billion bbls; remaining established reserves: 174.4 billion bbls).

15. *See infra* p. 427.

16. EUB (2002), *supra* note 7, at 2 (in total, 303 million barrels of crude bitumen was produced).

17. *See infra* p. 428.

18. *See infra* p. 428.

upgraded bitumen and synthetic crude oil will account for over 70% of total oil production.¹⁹

A number of major oil sands projects are either under construction or planned. Some of these mining projects include Suncor Energy's Project Millennium, Syncrude Canada Limited's Syncrude 21 Project, Shell/Chevron/Western Oil Sands' Muskeg River Mine-Scotford Upgrader Project, True North Energy/UTS Energy's Fort Hills Project, and ExxonMobil's Kearn Oil Sands Project.²⁰ In situ projects are Gulf Canada Resources' Surmount, PanCanadian Petroleum's Christian Lake, Petro-Canada's Mackay River, and Suncor's Firebag. Estimated total cost of these Athabasca deposit projects is \$17.7 billion (Can.).²¹ Proposed Cold Lake deposit in situ projects are estimated to cost an additional \$1 billion (Can.). The NEB, in 2000, estimated that the value of all publicly announced development plans totaled \$34 billion (Can.).²²

Costs of bitumen production have been reduced substantially over the last twenty years. For surface mining projects, costs are estimated to be in the \$15–\$18 (Can.) per barrel range, and for in situ projects either \$10–\$16 (Can.) or \$8–\$14 (Can.) per barrel, depending on the recovery technique used.²³

E. United States Markets for Bitumen and Synthetic Crude Oil

Three quarters of Canada's synthetic crude oil and blended bitumen is delivered to domestic refineries, with the remainder exported to the United States, particularly to the Midwest and Rocky Mountain areas (Petroleum Administration for Defense Districts III and IV). The NEB has stated that, "the [United States] market, with its declining indigenous conventional crude oil supplies, will be a vital outlet for the additional production of synthetic crude oil and blended bitumen."²⁴ The NEB added that "[i]t is likely that new United States markets will have to be developed."²⁵

The NEB also noted that refining of these products will require either refinery upgrading or upstream product improvement. The problem is that without hydrocracker facilities, synthetic crude does not produce yields comparable to light, sweet, conventional crude, and therefore large quantities cannot be used in most existing refineries.

Alberta government policy has strongly promoted oil sands development. Specific measures include a royalty regime with a light front-end load and federal and provincial government support for research on oil sands recovery and upgrading.

Priority of oil sands development in the event of competing or conflicting natural resource rights has been affirmed by the AEUB in rulings concerning

19. EUB (2002), *supra* note 7, at 3.

20. NEB (2000), *supra* note 11, at 50.

21. *Id.* at 49.

22. NEB (2000), *supra* note 7, at viii.

23. *Id.* at 40.

24. NEB (2000), *supra* note 7, at 66.

25. *Id.*

what came to be known as the “gas over bitumen” controversy. The issue was complaints by bitumen rights holders that production of associated gas by separate natural gas rights holders would impair in situ bitumen production, and because of gas pressure reduction, significantly reduce ultimate bitumen recovery. A public hearing by the NEB recommended that wells be shut-in and compensation provided for natural gas rights holders. Legislative changes and litigation, in which an Order in Council, establishing parameters for compensation plans was successfully challenged,²⁶ led to a NEB order on the application of Gulf Canada Resources Limited to shut-in 146 of 183 gas wells. The NEB’s statutory duty was to make a “public interest” determination. It granted the shut-in request, but recommended to the provincial executive that the gas producers be appropriately compensated.²⁷ The NEB has continued to study the issue and has made shut-in orders in several other gas production areas.²⁸

The legal rights of bitumen producers, relative to those of the holders of conventional petroleum and natural gas rights, were supported in the Alberta Court of Appeal 2003 decision *Alberta Energy Co. v. Goodwell Corp.*²⁹ After reviewing relevant scientific principles, the Alberta statutory regime, and the seminal case, *Borys v. CPR*,³⁰ the *Alberta Energy* court concluded that the oil sands lease holders’ rights to produce bitumen included the right to produce gas-cap gas incidental to bitumen recovery, subject to compensation of the gas rights holder for the gas-cap gas produced. The NEB order that had required the bitumen wells to be shut-in was set aside.³¹

F. Overall Crude Oil Exports³²

Canadian crude oil exports in 2001 were 1,367,469 bbls per day with over 99% of these exports to the United States. This represented a 9% share of the United States market and over 14% of United States crude imports. Petroleum products exports to the United States amounted to 140.9 billion bbls.

G. Natural Gas

Canada’s major natural gas reserves are found in the WCSB. Conventional natural gas has been estimated to be between 264 and 335 trillion cubic feet (Tcf) of ultimate resource potential, plus 75 Tcf of unconventional gas resources (coalbed methane and tight gas). In addition, the NEB identified Ontario and Scotian Shelf potential of 20 Tcf and Frontier (East Coast and Arctic) potential of 303 Tcf. Thus, total ultimate resource potential in the NEB’s more optimistic

26. *Gulf Can. Res. Ltd. v. Alberta*, [2001] 285 A.R. 307 (Can.).

27. *Gulf Can. Res. Ltd.*, ALTA. ENERGY & UTILS. BD. (Mar. 2000) (DECISION 2000-22), available at <http://www.eub.gov.ab.ca/bbs/documents/decisions/2000/2000-22.pdf>.

28. *Chard Area and Leismer Field Athabasca Oil Sands Area: Applications for the Production and Shut-in of Gas*, ALTA. ENERGY & UTILS. BD. (Mar. 2003) (DECISION 2003-023), available at <http://www.eub.gov.ab.ca/bbs/documents/decisions/2003/2003-023.pdf>.

29. *Alta. Energy Co. v. Goodwell Petroleum Corp.*, [2003] 233 D.L.R.4th 341 (Can.).

30. *Borys v. CPR*, [1953] 2 D.L.R. 65 (P.C.) (Can.).

31. *Goodwell Petroleum Corp.*, [2003] D.L.R.4th at ¶ 103.

32. NATURAL RES. CAN., STATISTICS ON NATURAL RESOURCES, at www.nrcan.gc.ca/statistics/energy/default.html (last visited Sept. 23, 2004).

scenario is 733 Tcf with cumulative production of 103 Tcf and remaining established reserves not yet connected to a transportation system of 44 Tcf.³³

All projections show a significant decline in WCSB production after the 2008–2013 period, with 95% of the established reserves being produced by 2025. Newly drilled wells begin producing at lower rates than wells drilled five years ago, and production from new wells declines faster than production from older wells.³⁴ However, data reported in the NEB's "Short-Term Natural Gas Deliverability Report" issued in December 2002 "indicate[d] that initial productivities for 2001 connections [were] stabilizing at 2000 rates and decline rates also appear[ed] to be stabilizing."³⁵

However, based on increases in unconventional and Scotian Shelf production, and potential Mackenzie Delta production transported to market through a Mackenzie Valley trunk pipeline, total Canadian production is projected to increase in the period to 2017.³⁶ In the NEB's more conservative scenario, relatively expensive Mackenzie Delta production begins in 2017, but overall production declines due to a projected decline in exports, as Canadian supply is less competitive than United States supply. The NEB has noted uncertainties, including relative drilling activity³⁷ and the early stage of coalbed methane development.³⁸

Approximately 3.8 Tcf annually, or 63% of total Canadian production, is exported to the United States. "Canada accounts for about 94 percent of United States imports"³⁹ and has a 15% share of the United States market. This has been projected to increase to 4.6–5 Tcf in the 2013–2018 period, then decline to 3.3–4.5 Tcf. At this peak, these exports "would account for [approximately] 18 percent of U.S. demand . . . declin[ing] to about 13 percent by 2025."⁴⁰ The NEB's two export cases, including United States regions, are shown in Figure 8.⁴¹ Export prices are assumed to increase from \$1.90 to \$3.35 (U.S.) by 2025 for western Canadian export points and from \$2.90 to \$4.40 (U.S.) for Niagara exports.⁴²

In its October 2002 report on Canadian Natural Gas Markets and Pricing, the NEB identified four current market issues: the Maturing North American Supply Basins; the "Enron Effect;" effect of reduced liquidity in the market; and

33. NEB (1999), *supra* note 3, at 42–43.

34. *Id.* at 47. This decline continued into 2000. NAT'L ENERGY BD., SHORT-TERM NATURAL GAS DELIVERABILITY FROM THE WESTERN SEDIMENTARY BASIN, 2002–2004 (Dec. 2002), available at http://www.neb-one.gc.ca/energy/EnergyReports/EMAGasSTDeliverabilityWCSB2002_e.pdf [hereinafter NEB (2002)].

35. NEB (2002), *supra* note 34, at 13.

36. NEB (1999), *supra* note 3, at 48–49.

37. *Id.* at 20.

38. NEB (1999), *supra* note 3, at 49.

39. NATURAL RES. CAN., *supra* note 32; Gaétan Caron, *North American Energy Supply Security*, Presentation at the 11th Annual US-Canada Energy Trade and Technology Conference (Nov. 7, 2003), at http://www.neb-one.gc.ca/newsroom/Speeches/GCNorthAmericanEnergySupplySecurityNECBC2003_11_07_e.htm.

40. NEB (1999), *supra* note 3, at 51.

41. *See infra* p. 429.

42. *Id.* at 50. In January–February 2004, natural gas market prices were in the \$4.50–\$6.50 (U.S.) range.

impact of credit worthiness troubles on gas-fired generation. These issues are discussed below individually.

1. Maturing North American Supply Basins⁴³

This is noted above in relation to the WCSB. The implication is that the increased drilling “treadmill effect” will continue with its consequential investment burden on producers. The United States has also experienced increasing maturity in many of its basins.

2. The “Enron Effect”⁴⁴

Fallout from the collapse of Enron has shaken confidence in energy trading companies and led to low share prices. Consequential cost cutting by selling assets such as pipeline systems has, as the NEB pointed out, provided cash but removed assets with low business risk that provide stable cash flow for companies. All of this has had a negative impact on the Canadian natural gas sector.

3. Effect of Reduced Liquidity in the Market⁴⁵

A consequence of post-Enron activities in the energy trading sector has been reduced liquidity. Intense focus on credit worthiness has made it increasingly difficult for small operators to buy and sell energy.

4. Impact of Credit Worthiness Troubles on Gas-Fired Generation⁴⁶

Some developers of proposed United States gas-fired electricity generation plants have responded to increased cost of debt by scaling down the number of proposed generation plants. This may have the effect of decreasing anticipated United States demand for Canadian natural gas, at least in the short-term.

III. THE CLOUDS ON THE HORIZON

A. *Rapidly Declining Natural Gas Reserves*

In early 2004, United States expectations that Canada would be the primary source of natural gas imports through 2025 dramatically changed. New forecasts by the United States Department of Energy’s Energy Information Administration (EIA) cut expected Canadian imports almost in half—remaining at current levels of 3.6 Tcf per year only to 2010 then declining to 2.6 Tcf by 2025.⁴⁷

This reassessment was based primarily on the NEB’s forecasts in its 2003

43. NAT’L ENERGY BD., CANADIAN NATURAL GAS MARKET DYNAMICS AND PRICING: AN UPDATE 39–41 (Oct. 2002), available at http://www.neb-one.gc.ca/energy/EnergyReports/EMAGasDynamicsPricingCanada2002_e.pdf. [hereinafter NATURAL GAS MARKET DYNAMICS]

44. *Id.* at 41.

45. NATURAL GAS MARKET DYNAMICS, *supra* note 43, at 41–42.

46. *Id.* at 42.

47. DEP’T OF ENERGY, ANNUAL ENERGY OUTLOOK 2004 WITH PROJECTIONS TO 2025 (Jan. 2004), available at [http://www.eia.doe.gov/oiaf/aeo/pdf/0383\(2004\).pdf](http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2004).pdf) [hereinafter U.S. EIA 2004].

to 2025 projections that lowered total expected Canadian production in 2025 from the 7.7 to 9.9 Tcf per year range, estimated in 1999, to a 4.3 to 6.1 Tcf range. Declining Alberta production, as shown above, was another factor taken into account in these revised United States projections.⁴⁸ Another factor identified, but not relied upon by the EIA, was the potential (depending on fuels actually adopted by particular producers) for future oil sands production to consume significant quantities of natural gas—as much as 1.3 Tcf per year.⁴⁹

B. Energy Sector Impacts of Kyoto Protocol Implementation

The Canadian energy sector, and particularly the Alberta-centered oil and gas and coal-fired electricity generating industries, have expressed concern about the economic impact of greenhouse gas (GHG) emissions reduction to meet Canadian Kyoto Protocol requirements. The December 2002 Canadian ratification of the Kyoto Protocol (Kyoto Protocol) to the United Nations Framework Convention on Climate Change,⁵⁰ triggered a commitment to reduce GHG emissions by 6% over 1990 levels prior to the 2008–2012 period. Such a reduction presents a major challenge since a “gap” of as much as 30% has been identified between the Kyoto Protocol target reduction and a business-as-usual emissions forecast.⁵¹

These energy industries point to heavy financial burdens relative to other economic sectors, regulatory uncertainty created by the federal ratification of the Kyoto Protocol, and disadvantage in the United States export market given the announced United States intention not to ratify the Kyoto Protocol.⁵² The energy industries underline the mismatch between the Kyoto Protocol’s apparent underlying assumptions and mechanisms and an industrial and regional economy, which is heavily based on primary energy resource development that is growing significantly, particularly in response to increasing energy demand in the United States. Large, long-planned facilities to develop Alberta’s oil sands are likely to be constructed prior to and during the Kyoto Protocol’s emissions reduction commitment period.⁵³ This development is threatened by a Kyoto-

48. *Id.* at 43. Cf. NAT’L ENERGY BD., ENERGY MARKET ASSESSMENT: SHORT-TERM NATURAL GAS DELIVERABILITY FROM THE WESTERN CANADA SEDIMENTARY BASIN 2003–2005 19 (Dec. 2003), available at http://www.neb-one.gc.ca/energy/EnergyReports/EMAGasSTDeliverabilityWCSB2003_2005_e.pdf (projecting a 3% deliverability decline by the end of 2005).

49. U.S. EIA 2004, *supra* note 47, at 43–45.

50. Framework Convention on Climate Change, June 4, 1992, S. Treaty Doc. No. 102-38 (1992), 31 I.L.M. 849, available at <http://unfccc.int/resource/convkp.html>; Kyoto Protocol to the United Nations Convention on Climate Change, Dec. 10, 1997, 37 I.L.M. 22, available at <http://unfccc.int/resource/country/index.html>. See also News Release, Department of Foreign Affairs and International Trades, Government of Canada Ratifies the Kyoto Protocol (Dec. 17, 2002).

51. GOV’T OF CAN., 2001 CANADA’S THIRD NATIONAL REPORT ON CLIMATE CHANGE 56 (2001), available at http://www.climatechange.gc.ca/english/publications/3nr/3NR_Published_Version_EN.pdf; GOV’T OF CAN., CLIMATE CHANGE DRAFT PLAN 7 (May 2002) (projecting Canadian business-as-usual emissions to be 810 Megatonne (MT) by 2010, which are 33% above 1990 levels). See also GOV’T OF CAN., THE CLIMATE CHANGE PLAN FOR CANADA 11 (Nov. 2002) (proposing a required reduction of 240 MT from this level).

52. Rick Hyndman, *Competitiveness of Industry Cannot be Undermined*, C³ VIEWS, Feb. 2002 at 6.

53. NEB (2000), *supra* note 11, at 87.

induced investment chill that appears to already have produced some delay and reconsideration announcements by oil sands project proponents.⁵⁴

Alberta, with its critical economic interest in energy resource development, has similar concerns. Future provincial energy resource revenues are in issue, particularly those resulting over the longer term from continued oil sands development, since oil sands facilities are already major GHG emissions sources.

The upstream oil and gas sector produces 30% of Alberta GHG emissions, and the electricity sector adds 22%.⁵⁵ However, two additional factors are central to the current debate. First, of the 30% of upstream oil and gas emissions, 23% are attributable to hydrocarbons exported to the United States.⁵⁶ This has sparked Canada's push in the Kyoto Protocol Conference of the Parties implementation foray for a credit against Canadian obligations for export of this "clean" natural gas to the United States.⁵⁷ A second factor is the relationship between Alberta GHG emissions sources and emissions from the rest of Canada. Alberta fossil fuel, primarily coal fired power generation, accounts for 51% of Alberta's total emissions, while in the rest of Canada these sources produce only 21% of emissions.⁵⁸ It is clear that the Alberta energy sector would bear a disproportionate emissions reduction burden.

These circumstances set the stage for a federal-provincial battle that commenced with an exchange of GHG emissions reduction plans and strategies and the introduction in Alberta of a climate change bill. The federal Climate Change Plan⁵⁹ aims to meet Canada's Kyoto Protocol target through a 240 MT national emissions reduction, including a 55 MT reduction for large industrial emitters that include natural gas processing plants, refineries, and oil sands plants. A major element of the Climate Change Plan is to establish targets for emissions reduction through negotiation of "covenants with a regulatory or financial backstop"⁶⁰ with these industrial emitters. Informal "non-papers," posted to Natural Resources Canada's website, describe a cap and trade scheme anchored by a prohibition on emission of GHGs without permits, with emissions intensity⁶¹ targets based on negotiated covenants and backup targets prescribed by regulation.⁶²

54. Chris Varcoe, *Oil Sands Investment "a risk:" U.S. Investors Warned Kyoto Boosts Costs of Oil Projects*, CALGARY HERALD, Dec. 18, 2002, at A-1; *Petrocan Rethinks Oil Sands*, CALGARY HERALD, Sept. 28, 2002, at A-1; Chris Varcoe, *Kyoto accord casts doubt over Fort Hills project*, CALGARY HERALD, Nov. 27, 2002, at D-2.

55. J. Donner, Alberta Environment Strategic Directions, *Alberta Emissions*, ALBERTA ENV'T, Feb. 5, 2002.

56. *Id.*

57. Based on emissions displaced in the United States, less emissions in Canada.

58. J. Donner, Alberta Environment Strategic Directions, *Alberta Emissions*, ALBERTA ENV'T, Feb. 5, 2002.

59. GOV'T OF CAN., CLIMATE CHANGE PLAN FOR CANADA (Nov. 2002), available at http://climatechange.gc.ca/plan_for_canada/plan/pdf/full_version.pdf.

60. *Id.* at 30.

61. GHG emissions relative to Gross Domestic Product (GDP).

62. LARGE FINAL EMITTERS GROUP, OVERVIEW OF LEGISLATION (n.d.), available at http://www.nrcan.gc.ca/lfeg-ggef/English/ol_en.pdf (last visited Sept. 24, 2004).

Alberta's Climate Change Plan also adopts an emissions intensity approach tailored to the circumstances of the energy industry.⁶³ It proposed, by 2020, to reduce emissions relative to Gross Domestic Product (GDP) by 50% of 1990 levels, and includes government education and other leadership actions, energy conservation, carbon management, technology development, conservation, enhancement of forest and agricultural sinks, and adaptation. Investment in energy and environmental technologies is central, including further development of ongoing pilot projects to sequester carbon dioxide in hydrocarbon formations.

Bill 37 was introduced as the Climate Change and Emissions Management Act in the Alberta Legislature in April 2003, and was intended to provide the statutory framework for the Alberta Climate Change Plan.⁶⁴ The Plan embeds the emissions intensity approach by specifying the provincial emissions reduction target relative to Gross Domestic Product as 50% of 1990 levels by 2020. The Bill authorizes the responsible minister, with Cabinet approval, to enter into voluntary sector agreements, and sets out elements of agreements, including: establishment of sector emission levels per unit of energy input or output, schedules for achieving emission targets, baselines to be used in conjunction with establishment of sectoral targets, monitoring, reporting, incorporation of sinks, emissions offsets and trading, and enforcement and compliance through financial and non-financial penalties. The emission levels established by these voluntary agreements can provide the basis for an emissions trading system.⁶⁵

Perhaps the most important objective of the Climate Change and Emissions Management Act⁶⁶ (Climate Change Act) is strategic. Its preamble reiterates Alberta's ownership of its natural resources and declares greenhouse gases— atmospheric carbon dioxide and methane—to be “not toxic [under atmospheric conditions] and are inextricably linked with the management of [other] renewable and non-renewable natural resources, including sinks.”⁶⁷

The statute itself declares sinks, defined as “component[s] of the environment that remove[] or capture[] [greenhouse] gases from the atmosphere through natural processes . . . and geological formations or . . . constructed facility[ies], used to store [greenhouse gases][,]”⁶⁸ to be “property rights.”⁶⁹

1. Potential Constitutional Litigation

What Alberta is doing is attempting to build a record of legislative intent in a bid to strengthen its position in potential litigation challenging the federal government's constitutional jurisdiction to enact legislation or enforce existing

63. ALTA. GOV'T, ALBERTANS & CLIMATE CHANGE: TAKING ACTION (Oct. 2002), available at <http://www3.gov.ab.ca/env/climate/actionplan/docs/takingaction.pdf>.

64. Alberta Bill 37, 2003 Spring Session, first reading (Apr. 17, 2003). Climate Change and Emissions Management Act, ch. C-16.7 (2003) (Can.).

65. This was explicit in § 5 of Bill 32, but Bill 37, while retaining regulation-making powers in relation to “emission offsets, credits and sink rights,” does not specifically mention emissions trading.

66. Climate Change and Emissions Management Act, ch. C-16.7 (2003) (Can.).

67. *Id.* at Preamble.

68. Climate Change and Emissions Management Act § 1(e)(i)–(ii).

69. *Id.* at § 9.

legislation to implement its climate change plans. The province has threatened such litigation and formed a legal team headed by former Premier Peter Lougheed who led Alberta's energy jurisdiction battle against the federal government in the late 1970s and early 1980s.

Alberta's theory is based on constitutional immunity of the province from federal legislation that purports to directly affect provincially owned natural resources.⁷⁰ A related objective is to underline the property and contractual elements of the Alberta Plan and relate these to the exclusive provincial jurisdiction to legislate in relation to "Property and Civil Rights in the Province."⁷¹ This may blunt potential federal government reliance on its residual "Peace, Order and Good Government"⁷² power to legislate in relation to matters of "national concern," provided such matters are reasonably distinct and specific and the scale of impact on provincial constitutional powers is not disproportionate. A further federal power concerns regulation of general trade and commerce,⁷³ a power that has been relatively narrowly interpreted by the courts, but may nevertheless be invoked to support federal GHG emissions trading legislation. Federal jurisdiction may potentially be based on the federal criminal law power. However, though climate change legislation will undoubtedly contain prohibitions and penalties, it is not clear that a complex regulatory and emissions trading scheme would be characterized as essentially criminal law.⁷⁴

At present, the outcome of any such litigation, should it be initiated, is highly speculative.⁷⁵ There is no federal implementing legislation for the province to challenge. The Climate Change Act is largely enabling legislation, with specific and potentially binding requirements to be established by future regulations. The Act has not been proclaimed to be in force. In any event, the core elements of the Bill are voluntary and consensual.⁷⁶ Alberta could refer a tailored constitutional question to the Alberta Court of Appeal, as it did in 1982, to successfully challenge a federal tax on exported natural gas.⁷⁷ However, there is not yet any new federal legislation or regulatory action, and there may be

70. CAN. CONST. (Constitution Act, 1867) pt. VI (Distribution of Legislative Powers), § 91.

71. *Id.* § 92(13).

72. CAN. CONST. (Constitution Act, 1867) pt. VI (Distribution of Legislative Powers), § 91(29). See A. Lucas, *Legal Constraints and Opportunities*, in *HARD CHOICES: CLIMATE CHANGE IN CANADA* (H. Coward & A. Weaver eds., Wilfred Laurier Press) (forthcoming 2004).

73. CAN. CONST. (Constitution Act, 1867) pt. VI (Distribution of Legislative Powers), § 91(2).

74. See *Attorney Gen. of Can. v. Hydro Qué.*, [1997] 3 S.C.R. 213.

75. Scholars are divided on the issue of jurisdiction to enact emissions trading legislation. See Joseph F. Castrilli, *Legal Authority for Emissions Trading in Canada*, in *THE LEGISLATIVE AUTHORITY TO IMPLEMENT A DOMESTIC EMISSIONS TRADING SYSTEM* APP. 1 (Elizabeth Atkinson ed., Renouf Publ'g Co. 1999); CHRIS ROLFE, *TURNING DOWN THE HEAT: EMISSIONS TRADING AND CANADIAN IMPLEMENTATION OF THE KYOTO PROTOCOL* (W. Coast Envtl. Law Research Found. 1998); Andrew Bachelder, *Using Credit Trading to Reduce Greenhouse Gas Emissions*, 9 J. ENVTL. L. & PRAC. 281 (1999); Nigel Bankes, *Shaping the Future or Meeting the Challenge?: The Federal Constitutional Proposals and Global Warming*, 36 *RESOURCES* 1 (1991).

76. See A.R. Lucas, *The Alberta Energy Sectors' Voluntary Approach to Climate Change: Context, Prospects and Limits*, in *BEYOND KYOTO: CANADIAN ENERGY POLICY IN THE SUSTAINABLE DEVELOPMENT ERA* (G. Bruce Doern ed., Univ. of Toronto Press) (forthcoming 2004).

77. Reference Re Proposed Fed. Tax on Exported Natural Gas, [1982] 1 S.C.R. 1004.

neither if federal action is limited to conditional spending (such as energy efficiency subsidies) and decisions within established federal constitutional jurisdiction (such as extra-provincial transportation and international trade). Further, it is difficult to apply provincial natural resource immunity in practice since provincially owned resources, once leased and produced, are severed, become the property of the private lessee, and lose provincial immunity. Accordingly, though the prospect of such constitutional litigation has somewhat receded, it continues to create uncertainty.

2. Continued Uncertainty

The results of these federal climate change actions and federal-provincial conflict have been regulatory and fiscal uncertainty for the Alberta energy sector. There are, however, signs of federal interest in accommodating Alberta and its energy sector. The most recent federal plan clarified the intent to apply an emissions intensity approach, similar to that of the province, to the energy sector.⁷⁸ In December 2002, the federal government announced that it would cap the amount that large industrial emitters will “have to spend to meet Kyoto targets at \$15 [(Can.)] a tonne of greenhouse gases.”⁷⁹ It stated further that “emissions intensity targets for the oil and gas sector [will be] set at a level not more than 15 percent below projected business-as-usual levels for 2010.”⁸⁰ These assurances produced grudging praise from major Canadian energy companies, including Petro-Canada and EnCana Corporation. However, in the absence of clear federal and provincial programs and emission reduction requirements, uncertainty still casts a shadow over oil and gas industry prospects and future industry investment.⁸¹

C. Arctic Natural Gas Pipelines

The period since 1999 has seen renewed interest in Arctic natural gas from both Alaska and the Canadian Mackenzie Delta region. This comes more than twenty-five years after the development and consideration of remarkably similar pipeline proposals in the 1970s.⁸² Then, as now, there were essentially two

78. See CLIMATE CHANGE PLAN FOR CANADA, *supra* note 55, at 28–32 (“Large Industrial Emitters”).

79. Steven Chase, *Ottawa to Limit Emission Cutback Burden*, GLOBE AND MAIL, Dec. 19, 2002, at B-1.

80. *Id.*

81. In January 2003, TrueNorth Energy LLP, a Koch Industries Inc. subsidiary, announced postponement of its \$3.3 billion (Can.) Fort Hills oil sands mine and upgrading project. They cited uncertain Kyoto Protocol costs as a significant factor. See Chris Varcoe, *Major Oil Sands Project Shelved*, CALGARY HERALD, Jan. 14, 2003, at A-1. Suncor Energy Inc., the largest oil sands operator, stated that GHG reduction costs were “manageable,” amounting to no more than twenty-seven cents per barrel. See Steve Chase & Patrick Brethour, *Suncor Allays Kyoto Fears*, GLOBE & MAIL, Jan. 10, 2003, at B-6. Nexen Inc. announced plans to spend \$155 million (Can.) on its Long Lake oil sands development in the coming year: See Chris Varcoe, *Nexen Softens Oil Sands Bombshell*, Calgary Herald, Jan. 15, 2003, at D-1.

82. See FRANCOIS BREGHA, *BOB BLAIR’S PIPELINE: THE BUSINESS AND POLITICS OF NORTHERN ENERGY DEVELOPMENT PROJECTS* (Lorimer 2d ed. 1981); EARLE GRAY, *SUPER PIPE: THE ARCTIC PIPELINE—WORLD’S GREATEST FIASCO?* (James T. Wills ed., Griffin House 1979); DONALD PEACOCK, *PEOPLE, PEREGRINES AND ARCTIC PIPELINES: THE CRITICAL BATTLE TO BUILD CANADA’S NORTHERN GAS PIPELINES* (J.J. Douglas Ltd. 1977); EDGAR J. DOSMAN, *THE NATIONAL INTEREST: THE POLITICS OF NORTHERN DEVELOPMENT 1968–75* (McClelland & Stewart Ltd. 1975).

pipeline routes, one up the Mackenzie Valley and the other along the Alaska highway corridor then through northern British Columbia.

In the 1970s, the Canadian Arctic Gas Pipeline group (CAGPL) and the Foothills Pipe Line/Alberta Gas Trunk Line Maple Leaf Project were proposed for the Mackenzie Valley. On the Alaska side, the Alaska Highway proposal was sponsored by the Maple Leaf proponents with the addition of the United States Pacific Northwest group.

The decision making process for these various proposals was complex and ultimately inconclusive. There was a series of ad hoc inquiries beginning with the landmark Berger Inquiry⁸³ that recommended against a pipeline across the Yukon North Slope. A ten-year moratorium on pipeline activities in the Mackenzie Valley was put in place to permit settlement and implementation of aboriginal land claims. This set the stage for a twenty-five year process of negotiations leading to a series of comprehensive land claim settlements in the Canadian Northern Territories. There was also an inquiry into Alaska Highway route socio-economic issues⁸⁴ and a public environmental assessment process for that route, including local community consultation.⁸⁵

All of this was in addition to the NEB's approval process under the National Energy Board Act,⁸⁶ in which the NEB evaluated competing proposals with a view to approving a single trunk pipeline. The Board rejected the CAGPL Mackenzie Valley project and approved a modified Foothills Alaska Highway line.⁸⁷ A major factor in the Canadian process was the United States Alaska Natural Gas Transportation Act (NGTA) of 1976.⁸⁸ The NGTA was driven by concerns about an impending United States natural gas shortage, and contemplated a decision by the United States President and Congress on a route for transportation of Prudhoe Bay gas by the beginning of September 1977, following recommendations from the Federal Power Commission (FPC). This set the stage, following inconclusive FPC formal recommendations, for Canada-United States negotiations that led to the September 1977 Northern Pipeline Agreement,⁸⁹ and by the Canadian Parliament's enactment of the Northern Pipeline Act in 1978.⁹⁰ The Northern Pipeline Act implemented the Agreement by granting a statutory certificate of Public Convenience and Necessity to Foothills for its Alaska Highway project.

83. THOMAS R. BERGER, *NORTHERN FRONTIER NORTHERN HOMELAND: THE REPORT OF THE MACKENZIE VALLEY PIPELINE INQUIRY* (Douglas & McIntyre, rev. ed. 1988).

84. KENNETH M. LYSYK ET AL., *ALASKA HIGHWAY PIPELINE INQUIRY* (Minister of Supply & Services 1977).

85. Under the federal Environmental Assessment Review Process (EARP). *See* HILL INQUIRY, ENVIRONMENTAL ASSESSMENT REVIEW PROCESS REPORT (1977); HURTUBISE ASSESSMENT PANEL, ENVIRONMENTAL ASSESSMENT REVIEW PROCESS REPORT (1979); COTTERILL TECHNICAL ASSESSMENT PANEL, ENVIRONMENTAL ASSESSMENT REVIEW PROCESS REPORT (1981); ROBINSON, FINAL REVIEW AND REPORT (1982).

86. National Energy Board Act, R.S.C., ch. N-7 (1985) (Can.).

87. NAT'L ENERGY BD., *1 REASONS FOR DECISION NORTHERN PIPELINES* (1977).

88. Alaska Natural Gas Transportation Act, 15 U.S.C. §§ 719-720 (1976).

89. Agreement on Principles Applicable to a Northern Natural Gas Pipeline, Sept. 20, 1977, U.S.-Can., 1230 U.N.T.S. 311.

90. Northern Pipeline Act, R.S.C., ch. N-26 (1985) (Can.).

However, an Alaska Highway pipeline was never built. Foothills constructed the southern "prebuild" section of its Alaska Natural Gas Transportation System (ANGTS), and in 1982, began shipping Alberta gas to United States markets. Completion of the project at that time could not be justified at prevailing prices, particularly in view of rapidly expanding natural gas supplies in the WCSB and in other North American regions. These expanding supplies and their prevailing prices also doomed the other Arctic pipeline proposals. Incremental extensions of the existing western Canadian pipeline system subsequently proved sufficient to tie in new supplies.

1. Current Pipeline Proposals

The major routes today are essentially the same as those in the 1970s. The leading proposals are the Alaska Highway pipeline and the stand-alone Mackenzie Valley pipeline, with the possible addition of an over-the-top Beaufort Sea line to tie into Prudhoe Bay. Though one of the Mackenzie Valley groups, the Artigas Resources Corporation (ARC), with a proposal for an over-the-top line, filed a pre-application project information package with the NEB in January 2002, none of the proponents has filed a complete application.

Foothills Pipe Lines still holds the certificate legislated for its ANGTS under the Northern Pipeline Act.⁹¹ It also has an easement from the federal government for the necessary Yukon right-of-way,⁹² and an institution, the Northern Pipeline Agency established under the Northern Pipeline Act charged, in place of the NEB with overseeing construction of its pipeline, including administration of environmental terms and conditions. Its proposed pipeline was also subjected to environmental impact assessment under the EARP process that existed in the 1970s. Foothills' position is that further EIA involvement under the Canadian Environmental Assessment Act (CEAA) is unnecessary, provided that Foothills maintains the original route mandated by the Canada-United States Agreement and authorized by its certificate of public convenience and necessity. That position is strengthened by a transitional provision in CEAA that received an interpretation favourable to Foothills in a 2002 Federal Court decision involving an Ontario freeway project.⁹³ However, Foothills must still address the concerns of Yukon First Nations, including the implications of proposed

91. *Id.* at § 21(1).

92. Easement granted by the Government of Canada to Foothills Pipe Lines (South Yukon) Ltd. on November 28, 1983.

93. Section 74(4) of the CEAA states that the Act does not apply where "the construction or operation of a physical work . . . was initiated before June 22, 1984" in respect of the issuance approval under a statutory provision that triggers CEAA review, unless, "the issuance . . . entails a modification, decommissioning, abandonment or other alteration to the project, in whole or in part." Canadian Environmental Assessment Act, R.S.C., ch. 37, § 74(4) (1992) (Can.). In *Canada v. Reg'l Municipality of Hamilton-Wentworth*, 2001 F.C.T. 381 (Fed. Ct. T.D.), the Federal Court confirmed that "construction" in section 74(4) includes a series of steps by which a project is implemented that may include, in addition to physical construction, official plan designation, financing, and land acquisition. These factors are also indicators of the nature of the project so that it may not be divided into constructed (such as the Foothills Southern Prebuild) and new unconstructed projects. The court also confirmed that in the absence of significant route changes, minor mitigative changes to a project do not constitute "modifications or other alterations" that would take a project out of the section 74(4) exclusion.

federal legislation to implement the environmental review provisions of the Yukon comprehensive land claim settlement agreement.⁹⁴

The Alaska Highway proposal sponsors now appear to be in a hold position. This is the result of announcements in March 2002 by the North Slope producers—Phillips, BP, and ExxonMobil—that the pipeline is not economic in the absence of new government incentives.⁹⁵

The Imperial Oil (a Canadian ExxonMobil subsidiary) Mackenzie Valley proposal, by contrast, has moved forward to project definition and preparation of regulatory applications. The Mackenzie Delta producers signed an agreement with the aboriginal-owned Mackenzie Valley Aboriginal Pipeline Corporation.⁹⁶ The latter, representing broad aboriginal interests in the region, and backed by the federal and Northwest Territories governments, aims to maximize aboriginal ownership and benefits in a Mackenzie Valley pipeline. The agreement contemplates equity participation by the aboriginal corporation of up to one third. It is now in the process of seeking financing. A significant factor is aboriginal mineral rights and access rights under the various land settlements in the region.

The over-the-top proposal is less well developed. It envisages parallel pipelines, over 1100 kilometers (Km) shorter than the Alaska Highway route, running from Prudhoe Bay, offshore to the Mackenzie Delta, then up the Mackenzie Valley to Edmonton. This project faces serious environmental scrutiny. It must also address the Canada-United States Agreement and United States and Canadian implementing legislation for the ANGTS. Moreover, in 2002, both houses of the United States Congress adopted provisions in their respective energy bills that preclude federal regulatory approval of an over-the-top route.⁹⁷

Finally, there is still a proposal to ship Prudhoe Bay gas to Valdez and liquefy it for shipment to Asian, and potentially, to United States markets. Another proposal under study is to convert methane to liquid products for shipment down the oil pipeline to Valdez.

2. The Prospects

The current proposals differ from those of the 1970s in a number of ways. Bankes and Wenig⁹⁸ have pointed out that the overall policy and regulatory context has shifted from an interventionist approach to a market system. This is a result of increased economic integration of continental markets following abandonment of regulated pricing and formal surplus determinations as a

94. Yukon Environmental and Socio-Economic Assessment Act, ch. 7, 2003 S.C. 94 (Can.).

95. Julie Earle, *BP Shelves Plans for \$20bn Alaska Gas Pipeline Project*, FIN. TIMES, Feb. 15, 2002, at 19.

96. News Release, Imperial Oil Ltd., Mackenzie Delta Producers Group Signs Memorandum of Understanding with Aboriginal Leaders (Oct. 15, 2001).

97. Press Release, Sen. F. Murkowski, (Sept. 12, 2002), at http://energy.senate.gov/news/rep_release.cfm?id=187111.

98. Nigel Bankes & Michael M. Wenig, *Northern Gas Pipeline Policy and Sustainable Development: Then and Now*, in BEYOND KYOTO: CANADIAN ENERGY POLICY IN THE SUSTAINABLE DEVELOPMENT ERA (G. Bruce Doern ed., Univ. of Toronto Press) (forthcoming 2004).

condition of gas exports, the energy provisions of the NAFTA, increased physical integration of the North American pipeline system, and light-handed regulatory approaches that support pipe-on-pipe competition.

Another change is the maturing of Canadian environmental assessment policies and processes. The Canadian Environmental Assessment Act⁹⁹ now mandates a process for full and comprehensive assessment, including cumulative effects of major pipeline projects. Even if the Foothills environmental assessment approvals remain valid, the more rigorous and sophisticated environmental approach represented by the CEAA, and other major environmental statutes that incorporate ecosystem integrity, must be addressed in implementing an Alaska Highway pipeline project.

A third more recent development is the position and role of aboriginal interests. In the 1970s, aboriginal groups were united in opposition to the pipeline proposals, taking the position that there should be no pipelines on claimed aboriginal lands until land claims were settled, and that in any event, pipeline development should not harm aboriginal traditional land use and cultural values.¹⁰⁰ Today, aboriginal rights have constitutional protection that guarantees consultation and participation by affected First Nations in natural resource projects on aboriginal lands, which gives First Nations legal rights and political clout unimagined in the 1970s.¹⁰¹ Recognition of aboriginal rights has led to comprehensive land claim settlements in a majority of the areas to be traversed by the pipelines.¹⁰²

The result is that the Territorial First Nations have not only supported pipeline proposals, but have sought equity participation in projects.¹⁰³ However, the positions of the various groups are far from uniform, and the regional political context is dynamic.¹⁰⁴

Another difference is the role of environmental non-governmental organizations (ENGOS). In the 1970s, a coalition of Canadian ENGOS vigorously challenged the pipeline proposals and promoted rational and environmentally sound (in today's terms, "sustainable") Arctic pipeline and oil and gas development.¹⁰⁵ They cooperated with aboriginal interests in various

99. Canadian Environmental Act, R.S.C., ch. 37 (1992) (Can.).

100. See George Manuel et al., Remarks at the Native Land Claims Plenary Session, in 2 NORTHERN TRANSITIONS: PROCEEDINGS OF THE SECOND NATIONAL WORKSHOP ON PEOPLE, RESOURCES AND THE ENVIRONMENT NORTH OF 60 99-106. (Canadian Arctic Res. Comm. 1978).

101. CAN. CONST. (Constitution Act, 1982) pt. II (Rights of the Aboriginal Peoples of Canada), § 35 as interpreted by the Supreme Court of Canada, particularly in *R. v. Delgamuukw*, [1997] 3 S.C.R. 113.

102. Western Arctic (Inuvialuit) Claims Settlement Act, ch. 24, 1984 S.C. 1 (Can.); Gwich'in Land Claim Settlement Act, ch. 53, 1992 S.C. 1 (Can.); Sahtu Dene and Metis Land Claim Settlement Act, ch. 27, 1994 S.C. 1 (Can.); Agreement, 1993, ratified by the Sahtu Dene and Metis Land Claim Settlement Agreement, ch. 27, 1993 S.C. 1; Yukon Umbrella Final Agreement, 1993.

103. Particularly through the Aboriginal Pipeline Group involving leaders from three of the four regional Northwest Territories aboriginal groups that support the stand-alone Mackenzie Valley pipeline. ABORIGINAL PIPELINE GROUP, MEMORANDUM OF UNDERSTANDING FOR A MACKENZIE VALLEY PIPELINE (2001), available at <http://www.aboriginalpipeline.ca/pdfs/MOU.pdf>.

104. Bankes & Wenig, *supra* note 99.

105. See Berger, *supra* note 76.

ways in the Berger Inquiry and other regulatory processes at the time.¹⁰⁶

Now, however, ENGOs are relatively less prominent, though Bankes and Wenig suggest that they may be influential players in northern pipeline policy development.¹⁰⁷ Like their 1970s counterparts, the ENGOs have neither strongly opposed pipeline development per se, nor expressed a preference for any particular route. But six prominent groups have endorsed a set of principles for northern oil and gas development, including pipeline projects that emphasize rigorous planning, environmental assessment processes, protected areas, and resources to support economic diversification and sustainable local economies.¹⁰⁸

3. Government Policies and Regulatory Process

In 1970, the Government of Canada supported the construction of a single pipeline,¹⁰⁹ initially supporting the CAGPL proposal and eventually supporting the ANGTS project. Today, there are no official pipeline policies, but it is clear that there is no longer unqualified government endorsement of the Alaska Highway project, and Ottawa has explicitly opposed the Alaska Highway subsidies proposed by the United States Senate.¹¹⁰ There appears to be recognition that the market may accommodate pipelines on both major routes, at least in the longer term.

Federal leasing policy and regulatory support for Canadian Arctic gas development, along with the opposition to United States Alaska Highway pipeline subsidies, implies support for Mackenzie Valley pipelines. Appointment of a federal negotiator to discuss proposals by the Aboriginal Pipeline Group seems to support local aspirations in the Mackenzie Valley, even though statements by federal Natural Resources Minister Herb Dhaliwal appear to rule out federal loans or loan guarantees.¹¹¹ Naturally, the Yukon and Northwest Territories governments have lined up in favour of the projects that would traverse their respective territories. The provinces of Alberta¹¹² and to a lesser extent, British Columbia, support the Alaska Highway pipeline. Considerable progress has been made in resolving the initially daunting problem posed by the multiplicity of regulatory and environmental assessment bodies with direct legal authority or interests in the assessment and approval of pipeline proposals.

In June 2002, the chairs of the boards and agencies responsible for environmental assessment and regulation of northern oil and gas development, including the principal energy regulator, the NEB, signed a Cooperation Plan for Environmental Assessment and Regulatory Review of proposed Mackenzie Valley pipelines.¹¹³ Consolidated Information Requirements were released in

106. Including the bias challenge of NEB Chair, Marshall Crowe, litigation that stalled the NEB hearings at a critical time. *Comm. for Justice & Liberty v. Nat'l Energy Bd.*, [1978] 1 S.C.R. 369.

107. Bankes & Wenig, *supra* note 98.

108. Canadian Arctic Resources Committee, *NORTHERN PERSPECTIVES*, Fall/Winter 2001, at 1.

109. GOV'T OF CAN., *EXPANDED NORTHERN PIPELINE GUIDELINES* (1972).

110. *Bush Opposes Senate's Alaska Pipeline Subsidy*, *CALGARY HERALD*, June 29, 2002, at D-4.

111. Sandra Cordon, *Dhaliwal Refuses Pipeline Support*, *GLOBE & MAIL*, Nov. 12, 2002, at A-4.

112. *Premier Joins Push for Pipeline*, *CALGARY HERALD*, June 5, 2002, at A-2.

113. N. PIPELINE IMPACT ASSESSMENT & REGULATORY CHAIRS COMM., *COOPERATION PLAN FOR THE*

September 2002.¹¹⁴ The Plan involves eight agencies with hearing processes, five others with direct statutory responsibilities and several more with broader mandates. They include, in addition to the NEB, the Canadian Environmental Assessment Agency, the Northwest Territories Water Board and land and water management agencies established under land settlements and implementing legislation, particularly the Mackenzie Valley Resource Management Act.¹¹⁵ The Plan calls for a process of environmental assessment and public consultation with a single set of joint hearings. This will undoubtedly expedite the process, but it is nevertheless a complex and potentially problematic regulatory adventure that raises possibilities of duplication and delay.¹¹⁶

On the Alaska Highway side, there are a large number of distinct First Nations, including groups with unsettled land claim issues, such as the Kaska Dena, a First Nation whose traditional lands are in both the Yukon and British Columbia. As mentioned above, the effect of the proposed Yukon Environmental and Socio-economic Assessment Act¹¹⁷ is problematic. Furthermore, as Bankes and Wenig have noted,¹¹⁸ the First Nations self-government process is further advanced in the Yukon than in the Northwest Territories, and the exercise by First Nations of lawmaking powers may affect an Alaska Highway pipeline.

The result is that while Northern Pipeline proposals are being rapidly advanced in response to market conditions, a number of uncertainties remain. There may be a largely integrated North American gas market, but there is no North American natural gas policy.¹¹⁹ Uncertainties include the role and position of the Canadian and United States governments in direct decision-making and potential subsidization. While considerable progress has been made in coordinating environmental assessment and regulatory processes, the large number of regulatory agencies and potential parties and the complexity of the issues, leaves ample room for uncertainty about the efficiency and effectiveness of the process. Coordinated decision-making is a large step beyond coordinated consultation of affected interests. Divergent First Nations interests may be difficult to accommodate, and as Bankes and Wenig have highlighted, process coordination does not guarantee that regulatory decisions can reflect an integrated approach that incorporates a range of socio-economic objectives or

ENVIRONMENTAL IMPACT ASSESSMENT AND REGULATORY REVIEW OF A NORTHERN GAS PIPELINE PROJECT THROUGH THE NORTHWEST TERRITORIES (June 2002). In January 2004, the Inuvialuit Settlement Region Environmental Impact Screening Committee referred the proposed Mackenzie Gas Project for review by a federal panel. News Release, Canadian Environmental Assessment Agency, Mackenzie Gas Project Sent to a Federal Environmental Review Panel by Inuvialuit Screening Committee (Jan. 30, 2004), available at <http://www.neb-one.gc.ca/newsroom/releases/nr2002/nrcirnwte.htm>.

114. Press Release, National Energy Board, Board Chairs release Consolidated Information Requirements for NWT Pipeline Project (Sept. 30, 2002), available at <http://laws.justice.gc.ca/en/M-0.2/80512.html>.

115. Mackenzie Valley Resource Management Act, R.C.S., ch. 25 (1998) (Can.).

116. Alexander J. Black, *Legal Principles Surrounding the New Canadian and American Arctic Energy Debate*, 23 ENERGY L.J. 81, 119 (2002); Bankes & Wenig, *supra* note 98.

117. Yukon Environmental and Socio-Economic Assessment Act, R.C.S., ch. 7 (2003) (Can.).

118. Bankes & Wenig, *supra* note 98.

119. Black, *supra* note 116, at 122.

that decisions can give sufficient weight to sustainable development policies.¹²⁰

D. North American Energy Trade Under the NAFTA

There is little doubt that Canada's significant oil, natural gas, and electricity exports to the United States, and the prospect of United States access to potentially large Mexican supplies, made energy trade a critical issue in the negotiations that led to the North American Free Trade Agreement (NAFTA).¹²¹ In fact, Canada and the United States had already cemented this energy trade relationship in the 1989 Canada-United States Free Trade Agreement (FTA).¹²² For Canada the energy issues during the 1991-92 NAFTA negotiations were: (1) to maintain and enhance its United States energy export position, and more generally, to avoid a separate United States-Mexico trade agreement that could relegate Canada in the longer term to merely one of the "spokes" in a wheel of which the United States is the hub;¹²³ and (2) to address certain trade "irritants," particularly with regard to coordination of Canadian and United States regulatory policies on Canadian natural gas exports.¹²⁴ There were essentially no tariff issues, and this remains the case today for the export of Canadian oil and for natural gas in the largely integrated North American market.

The most significant NAFTA provisions are found in Chapter 6, the Energy Chapter. It reiterates provisions of the General Agreement on Tariffs and Trade (GATT) and the FTA concerning the understanding that prohibitions or restrictions on energy trade generally do not permit minimum or maximum export or import prices, and that export taxes and duties on energy are not allowed unless such charges are applied generally to exported and domestically consumed products.¹²⁵

Perhaps most importantly for United States imports from Canada, under the NAFTA, Article 605, are that countries cannot implement quantitative restrictions otherwise justified under the GATT (such as temporary export restrictions to prevent critical shortages and measures to conserve non renewable resources), if such measures reduce the proportion of exports of products relative to total supply below the proportion that was available in the preceding three year period.¹²⁶ Nor can such restrictions establish export prices higher than domestic prices or disrupt normal channels of supply or normal proportions among energy goods such as that between crude oil and refined products.¹²⁷

This amounts to a North American energy resource supply guarantee. It is not new to the NAFTA, but reproduces almost exactly, provisions of the Canada-United States FTA. In addition, Article 607 of the NAFTA limits use of

120. Bankes & Wenig, *supra* note 98.

121. North American Free Trade Agreement, Jan. 1, 1994, Can. T.S. 1994 No.2, 32 I.L.M. 289.[hereinafter NAFTA].

122. Canada-U.S. Free Trade Agreement, Jan. 2, 1988, U.S.-Can., 27 I.L.M. 281 [hereinafter FTA].

123. J. Owen Saunders, *GATT, NAFTA and North American Energy Trade: A Canadian Perspective*, 12 J. Energy & Nat. Res. L. 4, 9 (1994).

124. NAFTA, *supra* note 121, at Art. 603.

125. *Id.* at Art. 604.

126. NAFTA, *supra* note 121, at Art. 605.

127. *Id.* at Art. 605.

the national security exemption found elsewhere in the Treaty, to justify restrictions on energy imports and exports. Such restrictions are allowed only in specified circumstances, such as when necessary to "respond to a situation of armed conflict involving the Party taking the measure[.]"¹²⁸

The Energy Chapter addresses energy regulation issues by reiterating national treatment requirements, tax and general quantitative limitation rights, and by exhorting parties to keep market-based objectives in view by ensuring that domestic regulatory bodies "avoid disruption of contractual relationships to the maximum extent practicable, and provide for orderly and equitable implementation . . . [of] such measures."¹²⁹ In practice, this regulatory measures provision has meant little in view of the increasing integration of the North American natural gas market and essentially open oil supply, though both Canadian and United States regulators have demonstrated their awareness of these NAFTA obligations.¹³⁰ The NEB is required, in exercising its powers and performing its duties, to give effect to the NAFTA and the Canada-United States FTA.¹³¹ In the case of natural gas exports, the NEB had already, following the FTA, moved from surplus tests and least cost alternative¹³² criteria for assessing longer term export applications, to a market-based approach, with a domestic consumer complaints procedure, export impact assessment, and a public interest scan.¹³³ This market-based approach has been adapted and maintained by the NEB.¹³⁴ Most recently, it denied a request from the Province of New Brunswick to implement rules for consideration of applications for short-term export orders for incremental supplies of Scotian Shelf gas, if those supplies cannot meet both domestic and export demand.¹³⁵

The limitations on export/import restrictions and export tax prohibitions that essentially establish energy sharing obligations, have been controversial in Canada. For the energy industry, they ensure stability and provide a marketing benefit for the industry and the producer provinces. The limitations also have the effect of removing the threat of new restrictive and burdensome federal energy taxes and regulatory policies, such as the 1980 National Energy Program.¹³⁶

The idea of a sale of perpetual access to Canadian natural resources makes many Canadians uncomfortable. There is a visceral fear of loss of sovereignty and diminishing domestic policy flexibility. This concern has been most

128. NAFTA, *supra* note 121, Art. 607(b).

129. *Id.* at Art. 606.

130. Saunders, *supra* note 123, at 10.

131. National Energy Board Act, R.S.C. ch. N-7, § 120.1(1) (1985) (Can.).

132. *Id.*, Part VI Regulations were amended to remove this export licence criterion: C.R.C. 1978, ch. 1056, § 6(2)(z)(iii), repealed SOR/89-43.

133. NAT'L ENERGY BD., REASONS FOR DECISION, IN THE MATTER OF REVIEW OF NATURAL GAS SURPLUS DETERMINATION PROCEDURES (July 1987).

134. NAT'L ENERGY BD., REASONS FOR DECISION, PROPOSED CHANGES TO THE APPLICATION OF THE MARKET-BASED PROCEDURE (May 1992).

135. NAT'L ENERGY BD., REASONS FOR DECISION, IN THE MATTER OF PROVINCE OF NEW BRUNSWICK APPLICATION RESPECTING SHORT-TERM EXPORT ORDER PROCEDURES (Sept. 2002).

136. CAN. DEP'T OF ENERGY, MINES & RESOURCES, THE NATIONAL ENERGY PROGRAM 1980, Report EP 80-4E (1980).

vigorously expressed in relation to the effect of the NAFTA on potential export of Canadian water. It also has been voiced in relation to non-renewable energy, with Article 605 described as “an astonishing surrender of sovereignty”¹³⁷ and requiring maintenance of “proportional export flows until resources are finally and completely exhausted[.]”¹³⁸ Government ministers are sometimes prickly about public perceptions that the trade obligations are forging a continental energy policy.¹³⁹ Though a North American Energy Working Group consisting of senior energy department officials from Canada, the United States and Mexico has been established, these officials have emphasized that the Group’s purpose is fostering communication and cooperation to enhance North American energy trade, not to develop North American Energy Policy.¹⁴⁰

A related Canadian concern is the implications of the NAFTA, chapter 11 investors’ rights provisions for future energy policy autonomy. These rights provide private investors with direct remedies against country governments in relation to state action that expropriates or is “a measure tantamount to nationalization or expropriation”¹⁴¹ of a foreign investment in the absence of fair market value compensation. A particular Canadian concern has been the prospect of loss of autonomy to implement public welfare programs such as medical care and state education programs. There have been few issues to raise these concerns in the energy sector. However, the 1999 settlement by the Canadian federal government of a Chapter 11 action by United States-based Ethyl Corporation resulting from a federal ban on Ethyl’s MMT gasoline additive,¹⁴² has worried the Canadian environmental community as well as government officials and caused some anxiety in the public.¹⁴³

137. Maude Barlow, *Washington to Canada: Fill ‘er Up*, GLOBE AND MAIL, Sept. 26, 2000, at A-12; Cf., Gary Park, *ANWR, U.S. Takeovers Revive Grumblings in Canada Over Its Open Energy Border*, PETROLEUM NEWS, Mar. 28, 2001, at 3.

138. FRED WILSON & STEVEN SHRYBMAN, CANADIAN CENTRE FOR POLICY ALTERNATIVES—NOVA SCOTIA, *SCOTIAN GAS: BREAKING THE FREE TRADE CONSENSUS* 6 (Aug. 2002).

139. The Hon. Herb Dhaliwal, Minister of Natural Resources, Canada, *Continental Energy Markets and Greenhouse Gas Emissions*, Speech to the Canadian Energy Research Institute and International Institute for Sustainable Development (Feb. 20, 2002).

140. N. AM. ENERGY WORKING GROUP, *NORTH AMERICA: THE ENERGY PICTURE* (June 2002), available at http://www.eia.doe.gov/emeu/northamerica/engnaewg.htm#_VIPD_1; Assistant Energy Secretary Vickey A. Bailey, Presentation to the North American Gas Strategies Conference (Nov. 5, 2001), available at <http://www.pi.energy.gov/library/presentationtoNAGSC011105.html>.

141. NAFTA, *supra* note 115, at Art. 1110.

142. HOWARD MANN & K. VON MOLTKE, *NAFTA’S CHAPTER 11 AND THE ENVIRONMENT: ADDRESSING THE IMPACTS OF THE INVESTOR-STATE PROCESS ON THE ENVIRONMENT* (Int’l Inst. for Sustainable Dev. & World Wildlife Fund 1999); Julie A. Soloway, *Environmental Trade Barriers Under NAFTA: The MMT Fuel Additives Controversy*, 8 Minn. J. Global Trade (1999). This concern was reinforced by a NAFTA arbitration tribunal decision that upheld a \$6 million (Can.) claim by S.D. Meyers, Inc. that its United States business of importing and treating Canadian toxic waste was harmed by a Canadian ban on export of PCB wastes. *S.D. Myers, Inc. v. Canada* (Nov. 13, 2000) (Liability Award); *S.D. Myers, Inc. v. Canada* (Oct. 21, 2002) (Damages Award); *S.D. Myers, Inc. v. Canada* (Dec. 30, 2002) (Costs Award) available at http://www.naftaclaims.com/disputes_canada/disputes_canada_sdmeyers.htm. An attempt by Canada to challenge the arbitral award in the Federal Court of Canada was unsuccessful. *See* Attorney Gen. of Canada v. S.D. Meyers Inc., 2004 F.C. 38 (Fed. T.D.).

143. Gordon Laxer, *Alberta as American Resource Plantation*, 4 PARKLAND POST (Fall 2000), available at http://www.ualberta.ca/~parkland/post/OldPost/Vol14_No3/AlbertaLaxer.html.

IV. CONCLUSIONS

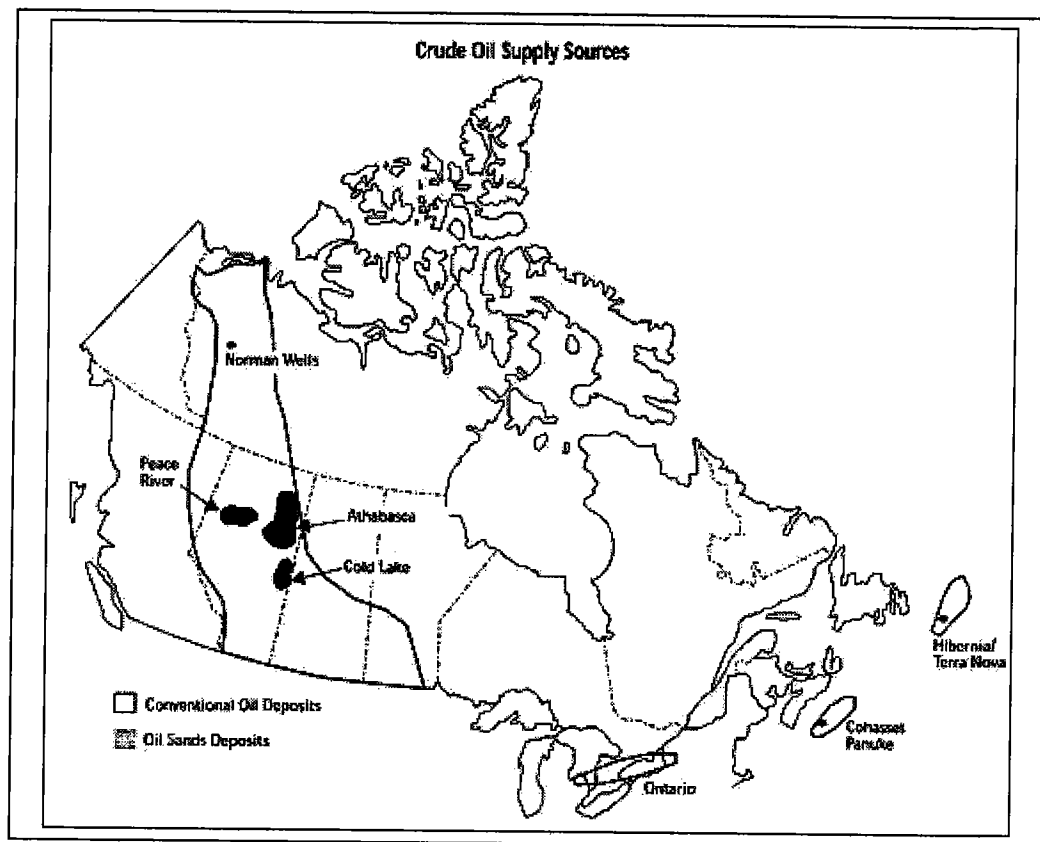
Canada will continue to have significant supplies of oil and natural gas available for United States export markets. While both gas and oil reserves are dropping and production has been in decline in the WCSB, major new applies are under development. There is also recent evidence of natural gas deliverability stabilization in the WCSB.

Arctic and East Coast offshore development are likely to bolster oil production. However, it is the massive oil sands reserves that are the key to future oil supplies from Canada. Production of bitumen and synthetic crude oil have increased significantly and a number of major new projects are either planned or under construction. Oil sands producers will have to address the issue of upgrading bitumen and synthetic crude oil exports. They will also have to deal with the regulatory and economic uncertainties related to efforts to reduce GHG emissions due to the Canadian ratification of the Kyoto Protocol.

Though potential Kyoto Protocol implementation most directly impacts new and existing oil sands operators, these economic effects also raise serious uncertainties for the entire Canadian oil and gas industry. In the case of natural gas, Arctic and East Coast frontier production, as well as unconventional coal bed methane and tight gas production, will cushion the WCSB decline. These additional supplies are likely to include Canadian Arctic gas delivered to Canadian and United States export markets by a major Arctic trunk pipeline or pipelines. Proposals for Arctic pipelines are now relatively advanced and formal Canadian regulatory filings are imminent. These projects face intensive scrutiny, not only as to available reserves and overall economic feasibility, but also as to potential impacts on the northern environment and on Aboriginal people in the region. However, regulatory coordination has largely been achieved, and aboriginal issues, including local benefits and potential equity participation in projects, have been addressed by pipeline proponents.

The NAFTA energy provisions appear to have benefited and strengthened Canada-United States oil and gas trade. Burdensome export taxes are much more difficult to sustain, and there are clear obligations to share potential future Canadian energy export shortfalls with United States customers. However, underlying the Canadian public's concerns remains, what some perceive to be, the irrevocable sale of Canada's energy resource patrimony.

Figure 1¹⁴⁴



144. NAT'L ENERGY BD., CANADIAN ENERGY: SUPPLY AND DEMAND TO 2025 63 (1999), available at http://www.neb-one.gc.ca/energy/supplydemand/1999/supplydemand1999_e.pdf.

Figure 2¹⁴⁵

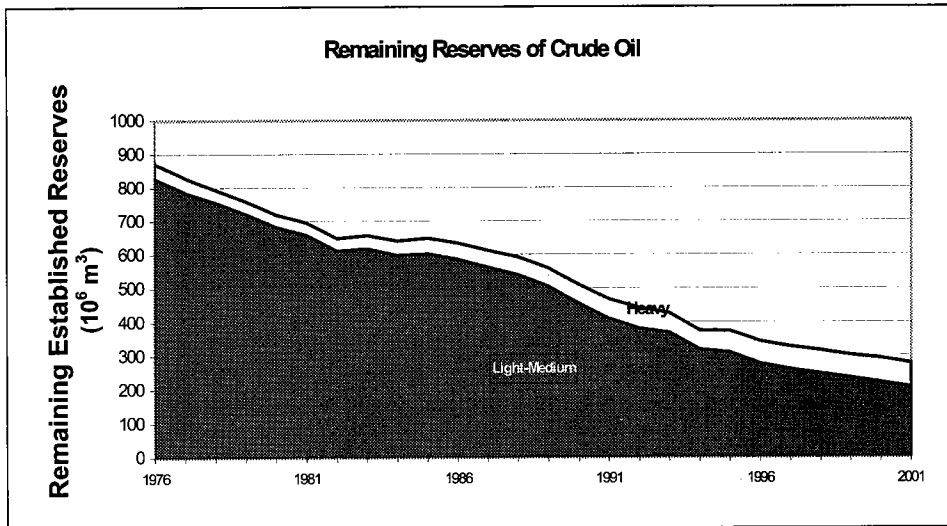
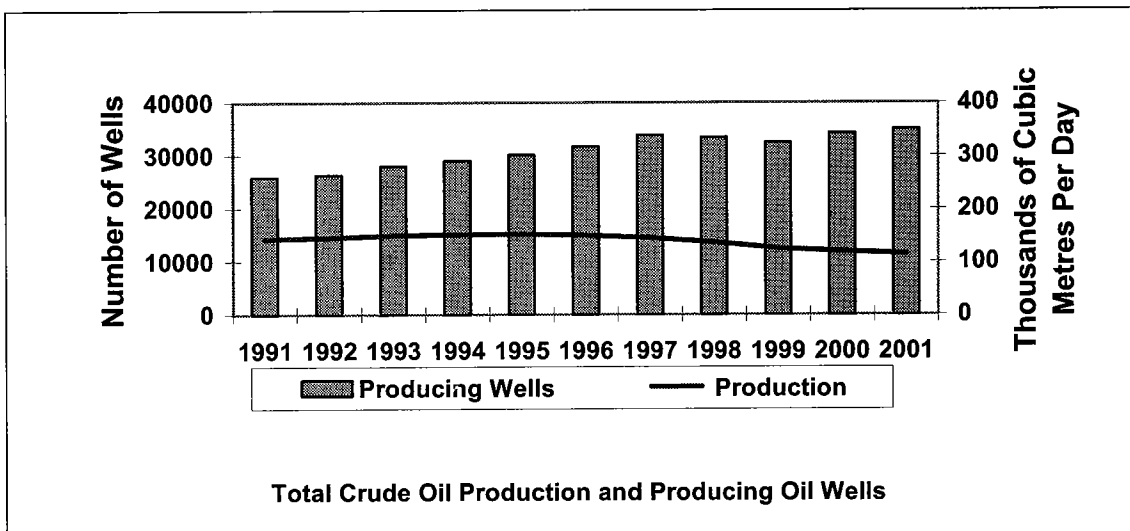


Figure 3¹⁴⁶



145. ALTA. ENERGY AND UTIL. BD., STATISTICAL SERIES 2002-98, ALBERTA'S RESERVES 2001 AND SUPPLY/DEMAND OUTLOOK 2002-2011 3-11 (2002), available at <http://www.eub.gov.ab.ca/bbs/products/STs/st98-2002.pdf>.

146. *Id* at 3-16 (2002).

Figure 4¹⁴⁷

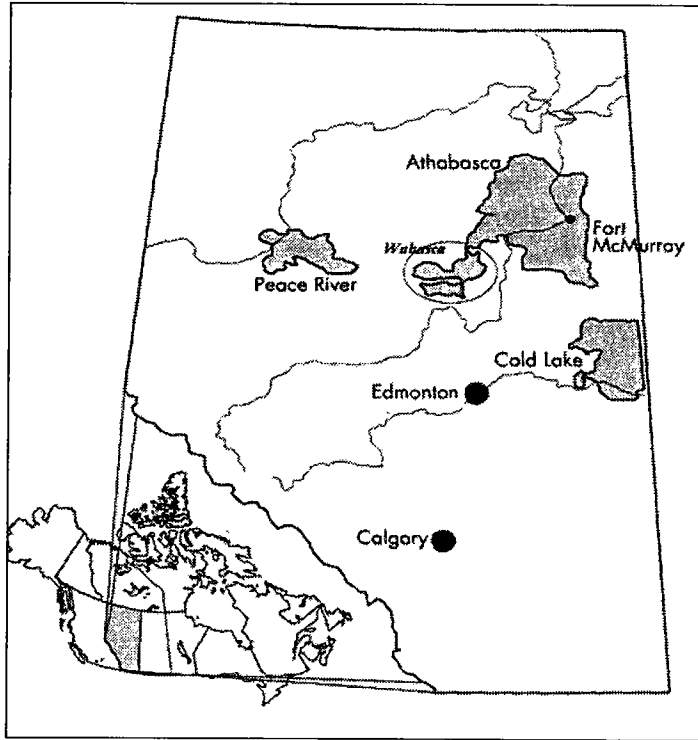
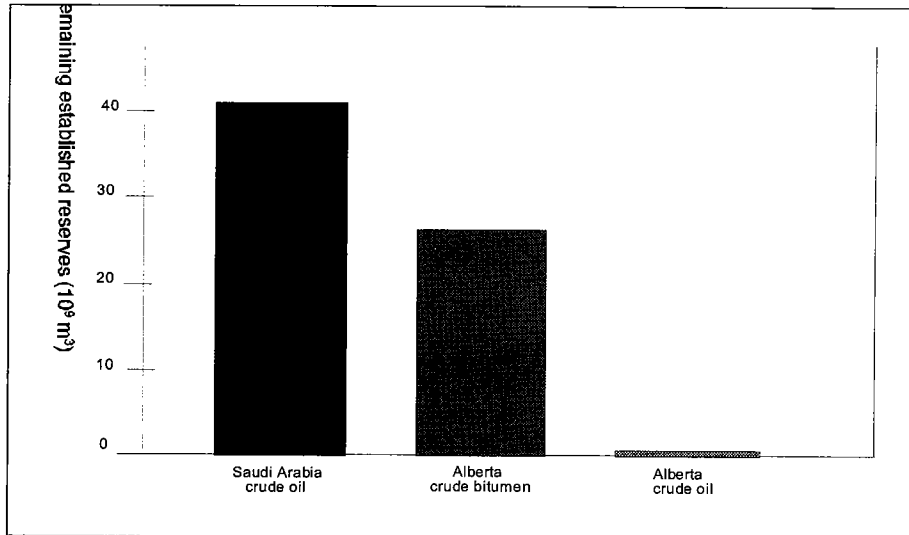


Figure 5¹⁴⁸



147. NAT'L ENERGY BD., CANADA'S OIL SANDS: A SUPPLY AND MARKET OUTLOOK TO 2015 4 (Oct. 2000).

Figure 6¹⁴⁹

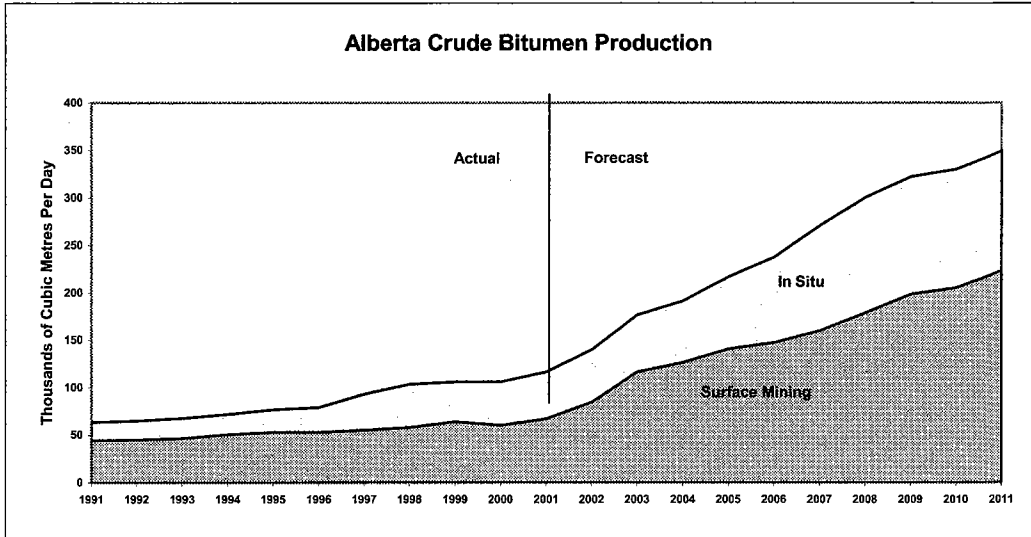
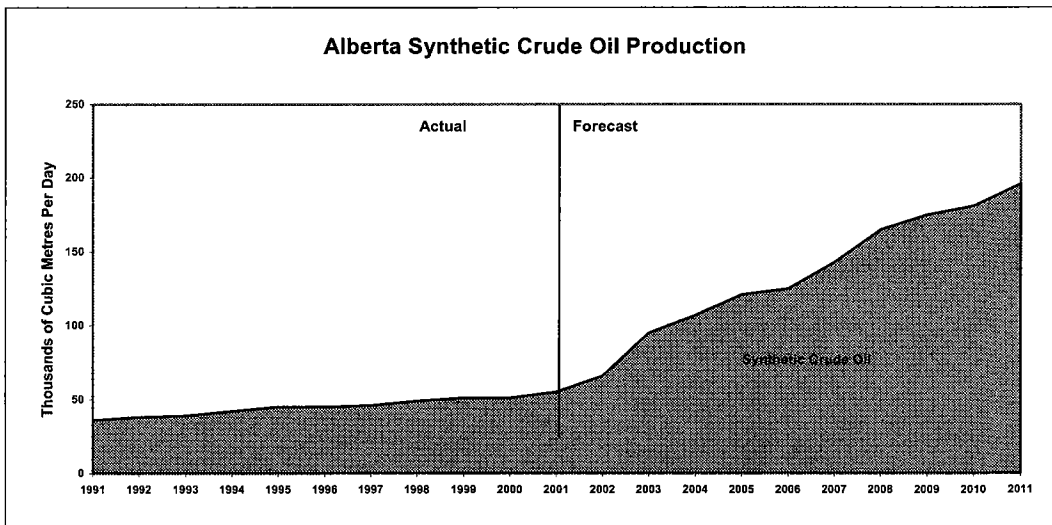


Figure 7¹⁵⁰

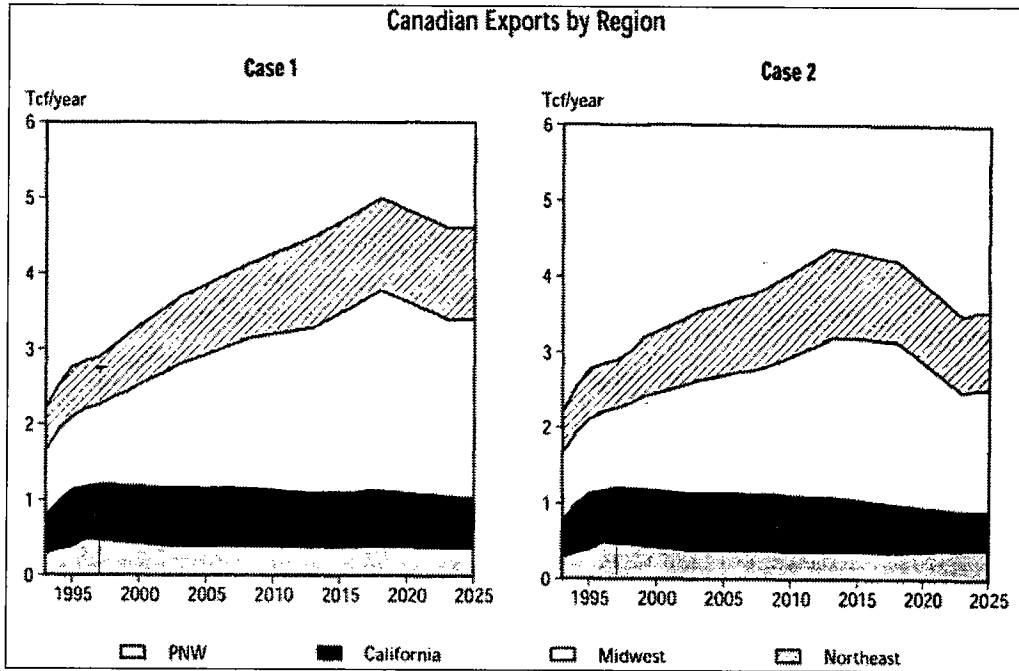


148. EUB (2003), *supra* note 2, at 2-15.

149. EUB (2002), *supra* note 7, at 2-14.

150. *Id.* at 2-14.

Figure 8¹⁵¹



151. NEB (1999), *supra* note 3, at 52.

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