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Appendices

When the Government is the Landlord

Economic Rent, Non-renewable Permanent Funds, and Environmental Impacts Related to Oil and Gas Developments in Canada

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West Coast Environmental Law • Yukon Conservation Society • Canadian Arctic Resources Committee • Saskatchewan Environmental Society

Regional Details: Alberta

The oil and gas sector in Alberta plays a significant role in both the national and provincial economies. Indeed, Alberta is Canada's largest producer of oil and gas and Canada's only producer of oil sands. Alberta produces 70 percent of Canada's oil and 80 percent of Canada's natural gas. Oil and gas products account for 60 percent of the province's exports.[1] In this appendix, we describe the methods the Government of Alberta uses to obtain revenues from this sizable oil and gas sector. We present quantitative estimates of revenue generation over the study period, as well as environmental impacts associated with oil and gas production in the province. We begin by providing background information on oil and gas production in Alberta.

Background

In the sections that follow, we identify the government authorities that play a role in regulating, managing and/or facilitating oil and gas production in Alberta. For each authority, we provide a brief description of its relevant responsibilities. We also present background information on the oil and gas sector, with figures for oil and gas production, employment in the oil and gas sector and gross domestic product associated with oil and gas production in Alberta.

Responsible Authorities

A number of departments and department divisions are involved in the development and management of oil and gas production in Alberta. These include the following:

1. The **Alberta Ministry of Energy** is responsible for providing policy, administration and a regulatory framework that guides the development of energy resources in the province. The Ministry of Energy comprises the Alberta Energy and Utilities Board and the Department of Energy.[2]
2. The **Alberta Energy and Utilities Board** regulates exploration, production, processing, transmission and distribution of energy resources within the province.[3]
3. The **Department of Energy** comprises various business units (described below) with responsibility for different aspects of the energy sector.
4. The **Natural Gas Business Unit** promotes and encourages responsible exploration and development of reserves and calculates and collects gas royalties. It also promotes the safe and orderly development of natural gas distribution systems.[4]
5. The **Conventional Oil Business Unit** promotes and encourages exploration and development of reserves, calculates and collects royalties from producers and markets the Crown's share of crude oil production through private sector marketing agents.[5]
6. The **Oil Sands Business Unit** promotes development and manages the Crown's interest in Alberta's extensive oil sands deposits. This includes planning and liaison with government and industry, and managing the oil sands land tenure and royalty program.[6]

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[1] Canadian Association of Petroleum Producers. See www.capp.ca.
[2] Government of Alberta, Ministry of Energy. *2002/03 Annual Report*.
[3] Op. cit.
[4] Op. cit.
[5] Op. cit.
[6] Op. cit.

Oil and Gas Production in Alberta

As we stated above, the vast majority of oil and natural gas production in Canada takes place in Alberta. Alberta produced 1,329 million barrels of oil equivalent in 2002, while British Columbia, the second-largest producer of oil and gas in Canada in 2002, produced just 209 million barrels of oil equivalent. In fact, Alberta accounts for 70 percent of Canada's crude oil production, 80 percent of Canada's natural gas production and 75 percent of total industry spending in Canada.[7]

Table 1 shows oil and gas production in Alberta from 1995 to 2002, inclusive. The table demonstrates recent trends in production. For example, between 1995 and 2002, production of conventional oil declined by 17 percent. Over the same time period, natural gas production in the province increased by 11 percent, and oil sands production increased by a significant 74 percent.

Table 1 Oil and gas production, Alberta, 1995 to 2002 (million BOE)

PRODUCTION	1995	1996	1997	1998	1999	2000	2001	2002
Conventional Oil	560	564	555	537	525	507	479	463
Oil Sands	156	162	193	215	207	222	240	271
Gas and Gas By-products	780	829	838	861	888	895	881	865
Total	**1,341**	**1,393**	**1,394**	**1,398**	**1,412**	**1,402**	**1,359**	**1,329**

Source: Canadian Association of Petroleum Producers

The substantial increase in oil sands production in Alberta is significant for several reasons. Alberta has the largest oil sands resource in the world, estimated at more than 1.6 trillion barrels of oil. Of this resource, an anticipated 315 billion barrels is considered potentially recoverable under anticipated technology and economic conditions, with only 2 percent of the established reserves produced to date. Initial established reserves, estimated at 28.3 billion cubic metres, would be sufficient to satisfy domestic demand for nearly 100 years.[8] The oil sands of Alberta are separated into three main deposits: the Athabasca, Cold Lake, and Peace River deposits. These areas cover a minimum of 4.3 million hectares, 729,000 hectares, and 976,000 hectares, respectively. The Athabasca deposit is by far the largest, comprising almost 80 percent of Alberta's oil sands reserves, followed by Cold Lake and Peace River, which contribute 12 percent and 8 percent of reserves, respectively.

Development of Alberta's oil sands deposits is poised for extensive growth over the next decade. Interest in oil sands development has been renewed because oil sands have the potential to meet increasing demands in both Canadian and American energy markets as production of conventional light oil declines. The 2002 oil sands production figure in Table 1 translates into approximately 740,000 barrels of bitumen (oil from oil sands) per day. Based on announced projects, production of marketable oil sands is forecasted to reach 1.9 million barrels per day by 2010, growing to 3 million barrels per day by 2020. The Alberta Energy and Utilities Board's *Supply/Demand Outlook 2002–2011* predicts that the province's production of bitumen will triple by 2011, when it will account for 75 percent of Alberta's total oil production.

[7] Canadian Association of Petroleum Producers Web site. See www.capp.ca for details.

[8] National Energy Board. *Canada's Oil Sands: A Supply and Market Outlook to 2015*, October 2000.

Oil and Gas Employment in Alberta

Table 2 presents direct employment figures for oil and gas production in Alberta. The table shows total employment figures for the province, as well as the share of total employment that can be attributed to oil and gas production. The figures indicate that while total employment in the province has increased quite substantially (by 22 percent between 1995 and 2002), employment directly associated with oil and gas production has declined (by 6 percent between 1995 and 2002). As a result, the portion of total employment attributable to oil and gas has also declined (by 23 percent between 1995 and 2002).

Table 2 Employment associated with oil and gas production and total employment, Alberta, 1995 to 2002

EMPLOY'T	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas	33,027	34,303	34,327	32,134	30,882	32,220	32,277	31,041
Total	1,369,000	1,408,000	1,458,000	1,515,000	1,553,000	1,588,000	1,632,000	1,674,000
% of Total	2.4%	2.4%	2.4%	2.1%	2.0%	2.0%	2.0%	1.9%

Source: 1997 to 2002 oil and gas employment figures from Statistics Canada, CANSIM Table 383-0009

Oil and Gas Gross Domestic Product in Alberta

Table 3 presents gross domestic product (GDP) associated with oil and gas production, total provincial GDP, and oil and gas GDP as a percentage of GDP generated by all industries. The figures in the table demonstrate that the growth of all industries combined has outpaced the growth of the oil and gas sector. Between 1995 and 2002, GDP associated with oil and gas production declined by 9 percent. Over the same period, “all industries” GDP increased by 38 percent. Oil and gas GDP as a percentage of “all industries” GDP declined by 34 percent between 1995 and 2002. These figures indicate that oil and gas production constitutes a declining portion of the total economy in the province of Alberta. At the same time, however, it is clear from the figures below that oil and gas production contributes significantly to the overall economy in Alberta, constituting 12 percent of provincial GDP in 2002.

Table 3 GDP associated with oil and gas production and provincial GDP, Alberta, 1995 to 2002 (million 2000$)

GDP	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas	18,658	18,708	18,972	19,106	19,737	17,509	17,256	17,067
All Industries	102,905	107,918	114,771	113,942	121,210	143,721	147,774	141,786
% of Total	18%	17%	17%	17%	16%	12%	12%	12%

Source: Oil and gas figures from Statistics Canada, CANSIM Table 379-0025

Oil and Gas Revenue Generation

In Alberta, the Crown owns 81 percent of all mineral rights. Individual Albertans and private interests own the remaining "freehold rights."[9] Crown-owned mineral rights are leased to oil and gas producers using a tenure process that issues licences or leases through a competitive, sealed-bid auction system. The highest bidder is awarded the rights to drill for and recover oil and gas.[10] Companies are granted the rights to explore for and develop petroleum and natural

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[9] Government of Alberta, Ministry of Energy. *2002/03 Annual Report*.

[10] See www.energy.gov.ab.ca/com/Tenure/Introduction/Tenure.htm.

gas resources in exchange for a portion of the value of the resources, which are returned to Albertans in the form of royalties, bonus bid payments and other taxes. Royalty payments vary with age, fuel prices and productivity, so newer wells that are less productive pay lower royalty rates than older wells that have a relatively higher productivity level. The bonus bid payment is a one-time payment made in exchange for mineral rights.[11] Oil and gas producers in Alberta are also liable for federal and provincial income taxes.

Table 4 Key means of revenue generation, Alberta

COMPONENT	KEY ATTRIBUTES
Crude Oil Royalty	Oil in Alberta is classified as old, new or third-tier. The Crown's royalty share of oil is highest for old oil (up to 40%) and lowest for third-tier oil (up to 24%).
Oil Sands Royalty	The oil sands royalty regime applies to all new investments in the oil sands. Prior to a project's payout date, the applicable royalty is 1% of project gross revenue. After a project payout, the applicable royalty is equivalent to the greater of 25% of net project revenue or 1% of gross revenue. All costs (operating and capital) are 100% deductible in the year in which they are incurred.
Natural Gas Royalty	The Crown royalty rates for gas are price-sensitive, and distinguish between old and new gas. The Crown royalty rate for new gas[12] ranges between 15% and 30%. The Crown royalty rate for old gas[13] ranges between 15% and 35%.
Coalbed Methane/Natural Gas in Coal Royalty	Coalbed methane/natural gas in coal is treated in the same fashion as natural gas when calculating royalties and tenure.
Ethane Royalty	The Crown royalty rate for ethane is price-sensitive and distinguishes between old ethane and new ethane.[14] The minimum rate for old and new ethane is 15%, but the maximum rate is 35% for old ethane and 30% for new ethane.
Propane Royalty	The Crown royalty rate for propane is price-sensitive. The minimum rate is 15% and the maximum rate is 30%.
Butane Royalty	The Crown royalty rate for butane is calculated each month and is price-sensitive. The minimum rate is 15% and the maximum rate is 30%.
Pentanes Plus Royalty	The Crown royalty rate for pentanes plus is price-sensitive and distinguishes between old and new pentanes plus.[15] The minimum rate for old and new pentanes plus is 22%, but the maximum rate is 50% for old pentanes plus and 35% for new pentanes plus.
Sulphur Royalty	The Crown royalty rate for sulphur is 16 2/3% of production.

[11] Alberta Department of Energy. *Alberta's Royalty Regime*. Presentation, September 15, 2003.

[12] Gas obtained from a pool discovered on or after January 1, 1974, or discovered before January 1, 1974, if no gas or other gas products from that pool had been sold or consumed for some useful purpose before January 1, 1974.

[13] Gas that does not qualify as new gas.

[14] The age definitions are the same for ethane as for natural gas.

[15] The age definitions are the same for pentanes plus as for natural gas.

Table 4 Continued

COMPONENT	KEY ATTRIBUTES
Methane Royalty	The Crown royalty rate for methane is price-sensitive and distinguishes between old methane and new methane.[16] The minimum royalty rate for old and new methane is 15%, but the maximum rate is 35% for old methane and 30% for new methane.
Bonus Bids	This is a voluntarily determined payment that reflects the bidder's expectation of the present value of excess economic rent for a parcel after all costs, royalties and taxes.
Corporate Income Tax	As of April 1, 2003, the general corporate income tax rate in Alberta was 12.5%.
Federal Income Tax	The net federal corporate income tax rate for oil and gas companies is 28%, against which the government allows a number of deductions.

As is the case in British Columbia, in Alberta there are a number of deductions and credits in place to encourage and facilitate oil and gas production in the province. Key initiatives include reduced royalties for deep wells, reactivated wells and low productivity wells. In addition, there are royalty reductions for research and development costs related to oilsands, royalty relief for enhanced oil recovery, the Gas Cost Allowance and the Alberta Royalty Tax Credit. Provincial oil and gas producers are also eligible for federal deduction and credit programs. These and other programs are briefly described in Table 5.

Table 5 Key deductions and credits related to oil and gas, Alberta

COMPONENT	KEY ATTRIBUTES
Low Productivity Wells	Reduced royalty rates for low productivity oil and gas wells.
Otherwise Flared Solution Gas Royalty Waiver Program (OFSG)	Waived royalty on uneconomic solution gas and gas by-products for wells approved under this program.
Oil Sands Research and Development (R and D)	Deduction of certain research and development costs from royalty payable in Alberta.
Compressing, Gathering and Processing Royalty Exemption	An exemption for gas consumed for compressing, gathering or processing natural gas derived from the same pool as the consumed gas.
Gas Consumed in Drilling and Production Royalty Exemption	An exemption gas consumed to drill or produce gas from a lease that is not an oil sands lease or an experimental oil project.
Gas Consumed in Oil Sands Schemes and Experimental Oil Projects	The Crown royalty share of gas consumed as fuel in commercial oil sands schemes or experimental oil projects may be waived.
Injected Gas or Gas Products Schemes Royalty Credit	An injection tax credit for injecting gas or gas products into a scheme ordered or approved by the Alberta Energy and Utilities Board (EUB).
Energy Efficiency Credit Program	A royalty credit for gas plant co-generation.
Sulphur Emission Control Assistance Program (SECAP)	Assistance that covers half the costs incurred to reduce sulphur emissions by 70%.
Gas Plant Efficiency Assistance Program (GPEAP)	Royalty credits for up to 50% of eligible costs to help large plants achieve 70% sulphur recovery.
Alberta Royalty Income Tax Deduction	A deduction available when provincial royalties paid exceed the federal resource allowance claimed.
Alberta Royalty Tax Credit (ARTC)	A refund of a percentage of Alberta Crown royalties paid on conventional oil and gas production, up to a maximum limit.

[16] The age definitions are the same for methane as for natural gas.

Table 5 Continued

COMPONENT	KEY ATTRIBUTES
Reactive Well Royalty Exemption	A royalty exemption on the first 8,000 m^3 of oil produced from wells that have been closed for 24 production months.
Third Tier Exploratory[17] Well Royalty Exemption	An exemption that encourages exploration and development of new reserves by exempting eligible production from Crown royalties.
Experimental Project Petroleum Royalty Reduction	A reduction that applies to the use of new technology and sets a maximum royalty rate for eligible production of 5%.
Low Productivity Well Royalty Reduction	A reduction that encourages additional production from low productivity wells[18] by capping royalty rates at 5% for up to 16,000 m^3 of oil production.
Horizontal Re-entry Well Royalty Reduction	A reduction that encourages the recovery of oil from mature pools by capping the Crown royalty rate.
Enhanced Oil Recovery Royalty Relief	Relief that encourages tertiary recovery techniques by forgoing royalties on a portion of the tertiary production.
Gas Cost Allowance (GCA)	A deduction from gas royalties to compensate for the costs of gathering, compressing and processing the Crown royalty share of the gas.
Deep Gas Royalty Holiday (DGRH)	A royalty holiday that applies to all new wells or deepened wells located below 2,500 metres.
Fuel Tax Exemption	Tax exemptions and rebates on fuel used for off-road commercial purposes.
CO_2 Projects Royalty	Up to $15 million over five years in the form of royalty credits to offset up to 30% of approved costs in approved CO_2 projects.
Federal Capital Cost Allowance	A deduction against income for depreciating property; Class 41 covers oil and gas equipment and allows a 25% writedown of equipment on a declining balance basis.
Federal Resource Allowance	A notional allowance in lieu of deduction of provincial royalties and freehold mineral taxes; over the study period, the deduction was 25% of taxable net resource profits.
Federal Exploration and Development Expenses	Exploratory and development expenses are grouped into one of three pools: Canadian Exploration Expenses (CEE), Canadian Development Expenses (CDE), and Canadian Oil and Gas Property Expenses (COGPE). The CEE balance of exploration expenditures is fully deductible against income, with any unclaimed portion carried forward indefinitely. Up to 30% of the CDE balance and up to 100% of the COGPE balance can be applied against income.
Federal Earned Depletion	An additional deduction from taxable income of certain exploration and development expenditures and other resource investments. The deductions for earned depletion are generally limited to 25% of the taxpayer's annual resource profits. [19]

[17] A third-tier exploratory well is an oil or oil sands well spudded after September 30, 1992.
[18] Eligible wells cannot produce more than 121 m^3 in any month during the qualifying period, and average monthly production must be 73 m^3 or less during the last six months of the qualifying period.
[19] While Earned Depletion has been phased out, federal government expenditures related to it continued until 2001.

Quantitative Results of Revenue Generation

Table 6 demonstrates the trend in revenues obtained from oil and gas producers in Alberta[20]. The major sources of revenue are royalties, especially natural gas royalties, and income taxes. Total revenues increased by 115 percent between 1995 and 2002.

Table 6 Revenue from oil and gas production, Alberta, 1995 to 2002 (million 2000$)

REVENUE SOURCE[21]	1995	1996	1997	1998	1999	2000	2001	2002
Natural Gas Royalty[22]	1,389	1,099	1,393	1,750	1,519	2,441	7,038	3,809
Crude Oil Royalty	1,227	1,146	1,486	969	487	1,072	1,466	933
Bonus Bids and Sales of Crown Leases	1,093	630	994	1,136	479	743	1,133	916
Income Taxes[23]	836	1,914	773	723	794	1,762	2,103	3,508
Royalty Tax Credit	(325)	(319)	(257)	(239)	(259)	(188)	(141)	(103)
TOTAL	**4,219**	**4,469**	**4,389**	**4,339**	**3,020**	**5,830**	**11,600**	**9,063**

Source: Alberta Department of Energy and the Canadian Association of Petroleum Producers

Table 7 compares trends in revenue with production to determine if the Alberta government is capturing relatively more or less revenue today than in 1995. The figures in the table show that while revenue generation increased between 1995 and 2002, production declined slightly over the same period. More specifically, between 1995 and 2002, revenues increased by 115 percent and oil and gas production declined by 1 percent. Despite the decline in overall production, revenues per unit of production increased from $3.1/BOE to $6.8/BOE between 1995 and 2002.

Table 7 Revenue generation and production, Alberta, 1995 to 2002

SUMMARY	1995	1996	1997	1998	1999	2000	2001	2002
Revenue (million 2000$)	4,219	4,469	4,389	4,339	3,020	5,830	11,600	9,063
Production (million BOE)	1,341	1,393	1,394	1,398	1,412	1,402	1,359	1,329
Revenue/Production (2000$/BOE)	**3.1**	**3.2**	**3.1**	**3.1**	**2.1**	**4.2**	**8.5**	**6.8**

Given the significant increase in oil sands production in Alberta (74 percent between 1995 and 2002), and the role that oil sands developments are expected to play in Alberta and Canada's

[20] As is stated in the methodology section of this report, the figures for revenue, cost of production and value of resource do not include oilsands.
[21] Some of the items that appear in Table 4 have been combined for the purposes of this table.
[22] Includes gas by-products.
[23] Provincial and federal income taxes.

energy future, the trend in revenue generation associated with oil sands production in the province warrants special consideration.

Oil Sands

Table 8 demonstrates trends in production and royalties for oil sands. It shows the trend in royalties from oil sands versus total royalties collected in Alberta, as well as the trend in oil sands production versus total oil and gas production in the province. The figures in Table 8 demonstrate that while oil sands production is increasing (by 74 percent), royalties from oil sands are decreasing (by 30 percent).

Table 8 Oil sands royalties and production, Alberta, 1995 to 2002

	1995	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
Total Royalties (million 2000$)	2,865	2,585	3,428	2,923	2,066	3,939	9,200	4,917
Oil Sands Royalties (million 2000$)	249	341	549	204	61	426	696	175
Oil Sands as a % of Total	**9%**	**13%**	**16%**	**7%**	**3%**	**11%**	**8%**	**4%**
Total Production (million BOE)	1,341	1,393	1,394	1,398	1,412	1,402	1,359	1,329
Oil Sands Production (million BOE)	156	162	193	215	207	222	240	271
Oil Sands as a % of Total	**12%**	**12%**	**14%**	**15%**	**15%**	**16%**	**18%**	**20%**

The apparent disconnect between the trend in oil sands production and royalties from oil sands is shown in Table 9. Oil sands royalties per unit of oil sands production declined between 1995 and 2002 from $1.6/BOE to $0.6/BOE.

Table 9 Oil sands royalties (2000$) per unit of production (BOE), Alberta, 1995 to 2002

	1995	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
Royalties/BOE	1.6	2.1	2.9	0.9	0.3	1.9	2.9	0.6

The Alberta government is getting less of a return on its investment in oil sands today than it did in 1995. The peak in royalties per unit of oil sands production in 2000 and 2001 is due to relatively higher commodity prices in these years. The year 2002 saw record oil sands production, yet very low royalties per unit of oil sands production. In 1996, the Government of

Alberta implemented a new generic royalty regime for oil sands. The basic elements of the new system are[24]

- a minimum 1 percent royalty payable on all production;
- 25 percent royalty payable on net project revenues after the developer has recovered all project costs including a return allowance;
- a return allowance set at the Government of Canada Long Term Bond Rate (LTBR); and,
- all project cash costs (operating and capital) are 100 percent deductible in the year incurred.

The implication of the generic royalty regime for oil sands developments is that only when a developer's cumulative project cash flows exceed operating and capital costs, as well as a return on invested capital equal to the LTBR, does Alberta participate in a significant royalty.[25] Judging from the figures presented above, this situation has yet to happen. Other research indicates that Alberta chose to set the net revenue royalty rate below the level that would capture 100 percent of the economic rent associated with oil sands projects,[26] instead allowing developers to capture economic rent that would, under a different royalty regime, accrue to the government and the citizens of Alberta.

Economic Rent in Alberta

Table 10 presents data for the value of oil (not including oil sands) and gas resources and the cost of oil (not including oil sands) and gas production annually for the province of Alberta. Figures are shown as 2000$/BOE, like the revenue figures in the previous section. The value of oil and gas resources in Alberta increased by 112 percent between 1995 and 2002. At the same time, the cost of production increased by 29 percent. In Alberta, the amount of economic rent available increased over the study period while the portion of economic rent that was captured by the government declined.

Table 10 Resource value, production costs and economic rent (2000$/BOE), Alberta, 1995 to 2002

	1995	1996	1997	1998	1999	2000	2001	2002
Resource Value	14.4	16.8	16.8	13.7	17.5	29.8	30.5	30.5
Production Cost	10.9	15.2	20.7	13.9	11.4	16.4	15.7	14.0
Economic Rent	3.5	1.6	0.0	0.0	6.1	13.4	14.8	16.5
Rent Capture	**89%**	**100%**	**100%**	**100%**	**35%**	**31%**	**58%**	**41%**

Source: Value figures from the Canadian Association of Petroleum Producers Statistical Handbook, Cost figures derived as per the methodology section of the report

Trends in Associated Environmental Impacts

Oil and gas developments in Alberta have resulted in land disturbance, acidifying emissions and greenhouse gas emissions. Each of these environmental impacts is described in more detail

[24] Masson, Richard and Bryan Remillard. *Alberta's New Oil Sands Royalty System*. Paper presented May 2, 1996.
[25] Masson, Richard and Bryan Remillard. *Alberta's New Oil Sands Royalty System*. Paper presented May 2, 1996.
[26] Op. cit.

below. Information related specifically to oil sands production can be found in a separate section below.

Land Disturbance

Table 11 shows the increase in the number of wells[27] drilled each year from 1995 to 2002; in 1995 a total of 8,442 oil and gas wells were drilled, compared to 12,989 wells in 2002. Adding these annual figures to the number of wells in existence in the province prior to 1995 provides an estimate of the total number of wells in the province. Prior to 1995, there were an estimated 84,600 oil and gas wells in Alberta.[28] This means that with the 8,442 wells drilled in Alberta in 1995, there were a total of 93,042 wells or wellpads in the province at the end of that year. Assuming one hectare of disturbance for each wellpad, 93,042 hectares of land was disturbed in Alberta in 1995 by oil and gas wellpads. Between 1995 and 2002, the footprint associated with wellpads in the province increased from 93,042 to 171,507 hectares. That 84 percent increase in the amount of land disturbed by oil and gas wellpads occurred in just seven years.

Table 11 Number of wells drilled in Alberta, 1995 to 2002

WELLS DRILLED	1995	1996	1997	1998	1999	2000	2001	2002
Oil	3,235	4,439	5,301	1,693	1,751	3,198	2,558	2,645
Gas	2,877	3,117	4,278	4,033	5,622	7,353	8,789	6,949
Abandoned and Suspended	2,330	2,647	2,670	1,902	1,676	2,168	2,281	3,395
Total Annual Growth	8,442	10,203	12,249	7,628	9,049	12,719	13,628	12,989
CUMULATIVE FOOTPRINT (hectares)	93,042	103,245	115,494	123,122	132,171	144,890	158,518	171,507

Source: Alberta Energy and Utilities Board Statistical Series 57: Field Surveillance Provincial Summaries, 1999/2000 and 2002; www.eub.gov.ab.ca/BBS/energystats/EUBactivity/feildactivity+/default.htm

The trend of increasing numbers of wells is expected to continue. The Petroleum Services Association of Canada forecasted record drilling activity in Canada for 2003. In Alberta, 13,435 wells were forecasted, up from the 2002 figure of 12,989.[29] While some abandoned wells are reclaimed each year, the overall footprint continues to grow.

Table 12 shows the total length of pipelines built in Alberta each year from 1995 to 2002. Prior to 1995, there was a total of 190,754 kilometres of pipelines in the province. Adding this figure to the 1995 figure reveals the total kilometres of oil and gas pipelines in Alberta at the end of 1995: 207,541 kilometres. The cumulative figures in Table 12 demonstrate the expansion of oil and gas pipelines in the province between 1995 and 2002, from a total of 207,541 kilometres in 1995 to a total of 319,121 kilometres in 2002. That is a 54 percent increase in the total kilometres of pipelines in the province in just seven years.

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[27] includes wells drilled for oil sands developments as well as conventional oil and natural gas.

[28] Alberta Energy and Utilities Board Statistical Series 57.

[29] Whitely, Don. “Drillers Headed to Record Year in Canada: 46% Increase Expected in BC.” *Petroleum News*, Vol. 8, No. 32, 2003.

Table 12 also estimates the size of the footprint associated with oil and gas pipelines in Alberta from 1995 to 2002. The footprint estimate is based on the average right of way for pipelines in British Columbia (15 metres). The footprint associated with pipelines in Alberta has increased from 311,311 hectares in 1995 to 478,681 hectares in 2002.

Table 12 Length of pipelines completed in Alberta, 1995 to 2002, kilometres

PIPELINES	1995	1996	1997	1998	1999	2000	2001	2002
Provincial	16,327	12,823	16,163	21,611	14,295	16,055	18,777	10,799
National Energy Board	460	98	11	800	14	97	3	34
Total	**16,787**	**12,921**	**16,174**	**22,411**	**14,309**	**16,152**	**18,780**	**10,833**
Cumulative	207,541	220,462	236,636	259,047	273,356	289,508	308,288	319,121
CUMULATIVE FOOTPRINT (hectares)	**311,311**	**330,693**	**354,954**	**388,570**	**410,034**	**434,262**	**462,432**	**478,681**

Source: Alberta Energy and Utilities Board Statistical Series 57, National Energy Board, personal communication

Acidifying Emissions

In addition to land disturbances, oil and gas production in Alberta results in the release of acidifying emissions of nitrogen oxides (NOx) and sulphur dioxide (SO_2). Between 1995 and 2002, annual emissions of nitrogen oxides increased by 21 percent, while annual emissions of sulphur dioxide declined by 21 percent[30].

Table 13 Emissions of NOx and SO_2 from the upstream oil and gas sector, Alberta, 1995 to 2002, tonnes

EMISSION	1995	1996	1997	1998	1999	2000	2001	2002
Nitrogen Oxides	243,115	252,861	286,879	292,120	304,929	310,317	300,931	294,080
Sulphur Dioxide	271,043	253,742	255,140	222,798	195,800	226,122	219,283	214,290

Source: 1995 to 2000 figures from Clearstone Engineering, Emissions Inventories for GHG and CAC, Volume 1 and 2, produced for Canadian Association of Petroleum Producers, 2004

Greenhouse Gas Emissions

Oil and gas production also results in emissions of greenhouse gases. Table 14 estimates the greenhouse gases (in carbon dioxide equivalents) associated with upstream oil and gas emissions in Alberta between 1995 and 2002[31]. Annual greenhouse gas emissions associated with oil and gas production in Alberta increased by 11 percent between 1995 and 2002. This increase is despite improvements in emissions per unit of oil and gas produced.

Table 14 Upstream greenhouse gas emissions, Alberta, 1995 to 2002, kilotonnes

EMISSION	1995	1996	1997	1998	1999	2000	2001	2002
CO_2E	52,548	55,623	58,603	59,804	60,062	61,366	59,510	58,155

Source: 1995 to 2000 figures from Clearstone Engineering, Emissions Inventories for GHG and CAC, Volume 1 and 2, produced for Canadian Association of Petroleum Producers, 2004

[30] Emissions associated with oil sands not included.
[31] Emissions associated with oil sands not included.

Trends in Associated Environmental Impacts: Oil Sands

Due to the significant increase in oil sands production realized in Alberta between 1995 and 2002 (74 percent), as well as the role that oil sands production is expected to play in Canada's energy future, it is worth conducting a more in-depth analysis of the environmental impacts specifically associated with oil sands production. In the sections that follow, we describe trends in environmental impacts associated with land disturbance, acidifying emissions and greenhouse gas emissions as they relate specifically to oil sands.

Land Disturbance

Northeastern Alberta, where the oil sands are located, has most of the remaining core boreal forest habitat and consists of large, unfragmented areas of high ecological value. The cumulative impact of oil sands development represents a significant surface disturbance to the landscape of the boreal forest. The scale of development in the oil sands region is contrary to the long-term sustainability of this ecosystem, and especially to the ecological integrity of the local and regional landscapes where these developments are proposed to occur. Wetlands in the area provide an important ecological service in terms of water regimes and habitat for wildlife. All wetland types are home to a wide variety of plants and wildlife, including rare and endangered species. Peatlands, too, deliver a vital ecological service, both as a filtration system for clean water and as a store of carbon, acting as net carbon sinks.[32]

Very little land area that has been directly affected by oil sands mining operations has been restored to a condition with equivalent capability to its pre-mining state, and no oil sands operations have yet received a reclamation certificate from the Government of Alberta. When Suncor has completed mining on existing leases, 14,000 hectares of boreal ecosystem will have been altered. Cumulative land disturbance since the start-up of Suncor's operations in 1967 is 7,610 hectares and, to date, 732 hectares have been reclaimed[33]; however, this reclamation has not yet received certification from the Alberta government.[34] Syncrude's operations have disturbed 17,653 hectares. Only 3,290 hectares of land have been reclaimed, and only 191 hectares of this reclaimed land is considered "permanently reclaimed." None of Syncrude's land has been certified by the Government of Alberta to date.[35]

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[32] *The Alberta GPI Accounts: Wetlands and Peatlands*. Available at www.pembina.org.

[33] Suncor Energy. *2003 Report on Sustainability: What's at Stake?* Available at www.suncor.ca.

[34] Alberta Environment's definition of reclamation, which sets the requirements to achieve a reclamation certificate, requires that disturbed land be restored to *equivalent land capability*, defined as follows: "… the ability of the land to support various land uses after conservation and reclamation is similar to the ability that existed prior to an activity being conducted on the land, but … the individual land uses will not necessarily be identical." (Source: www3.gov.ab.ca/env/protenf/landrec/definitions.html#equiv_land_capability).

[35] Syncrude Canada. *2002 EH&S Report*, p. 45–46.

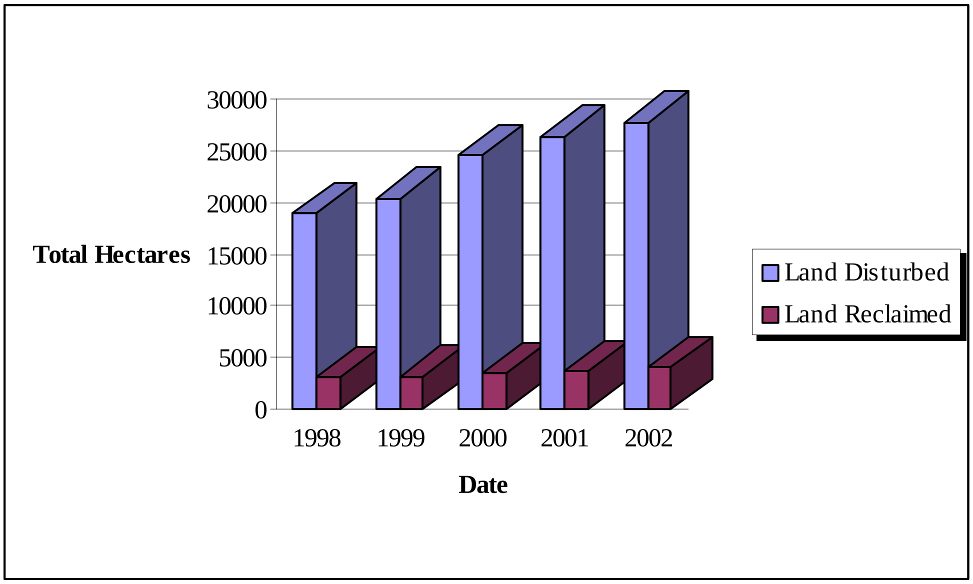

Figure 1 Cumulative land disturbed and reclaimed by Suncor and Syncrude's oil sands mines

Acidifying Emissions

Burning petroleum coke and/or natural gas to produce steam that is used for bitumen extraction, using diesel truck fleets, and upgrading bitumen result in emissions of sulphur dioxide ($S0_2$) and nitrogen oxides (N0x). The N0x/$S0_2$ Management Working Group of the Cumulative Environmental Management Association (CEMA) undertook an assessment of regional acidifying emissions in 2003. Modelling from this assessment predicts an increase in acidifying emissions from 204.53 tonnes per calendar day in 1970 to 643.41 tonnes per calendar day in 2032, when bitumen production reaches 3,239,000 barrels per day.

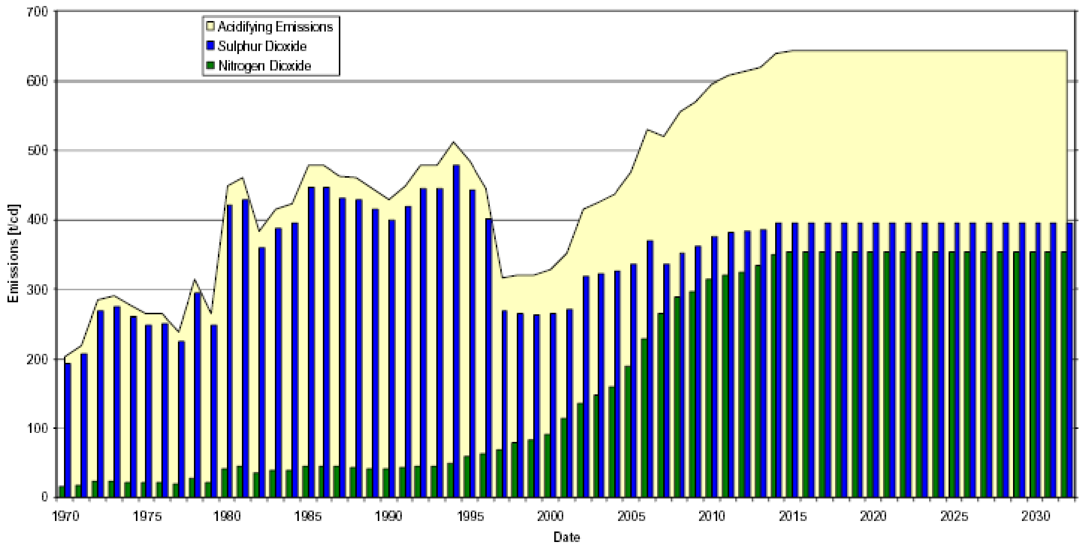

Figure 2 Annual Acidifying Emissions in the Oil Sands Region

Potential Acid Input (PAI) is the preferred method for evaluating the overall effects of acid-forming chemicals on the environment, because it accounts for the acidifying effect of the sulphur and nitrogen species, as well as the neutralizing effect of available base cations. Alberta Environment has created critical loads to protect less, moderately and highly sensitive ecosystems from PAI. Table 15 shows the predicted increase in the areas that will be subject to deposition rates exceeding critical loads.

Table 15 Summary of Potential Acid Input (PAI) Predictions

PARAMETER	1970 to 2002	2003 to 2017	2018 to 2032
Area > 0.17 keq/ha/yr [ha]	323,889	810,595	1,277,379
Area > 0.25 keq/ha/yr [ha]	114,857	297,928	548,119
Area > 0.5 keq/ha/yr [ha]	23,815	146,381	199,680
Area > 1.0 keq/ha/yr [ha]	3,171	47,963	65,849

Source: Report B in the Evaluation of Possible Management Frameworks for Acid Deposition in the Athabasca Oil Sands Region.

Greenhouse Gas Emissions

The development of new energy sources in Canada to fuel exports to the United States and meet increased domestic demand is predicted to result in an additional 98.1 Megatonnes (MT)/year of greenhouse gas (GHG) emissions by 2010. Of this increase, 60 MT, or 61 percent, will originate from the development of Alberta's oil sands as production levels increase to two million barrels per day by 2010.[36]

Oil sands operations are significant emitters of GHGs because of the energy intensity required to extract bitumen from the sand. The main source of GHG emissions associated with oil sands mines is the co-generation of electricity and steam. Similarly, the main source for Steam Assisted Gravity Drainage (SAGD) in *in situ* projects is the generation of steam for well injection.

While progress has been made in reducing the GHG intensity of oil sands production per barrel, increases in production have resulted in significant increases in GHG emissions. For example, although Suncor achieved a 23 percent decrease in intensity between 1998 and 2002, its total GHG emissions increased by 70 percent.[37] Similarly, while Syncrude has committed to gains in efficiency of 1 percent per year, plans to increase production by 60 percent will result in an increase in absolute GHG emissions.[38]

Summary

The increase in revenue generation observed in Alberta is largely driven by relatively higher fuel prices in recent years. The significant increase in the amount of revenues per unit of production between 1999 and 2000 corresponds with a 58 percent increase in the price of oil and a 94 percent increase in the price of natural gas over the same time period (see Figure 3).

[36] David Suzuki Foundation. *Fuelling the Climate Crisis*, 2002. Available at www.davidsuzuki.org.
[37] Suncor Energy. *2003 Report on Sustainability: What's at Stake?* Available at www.suncor.ca.
[38] Syncrude Ltd. *Sustainability Report 2002*. Available at www.syncrude.com/investors/ar02/index.html.

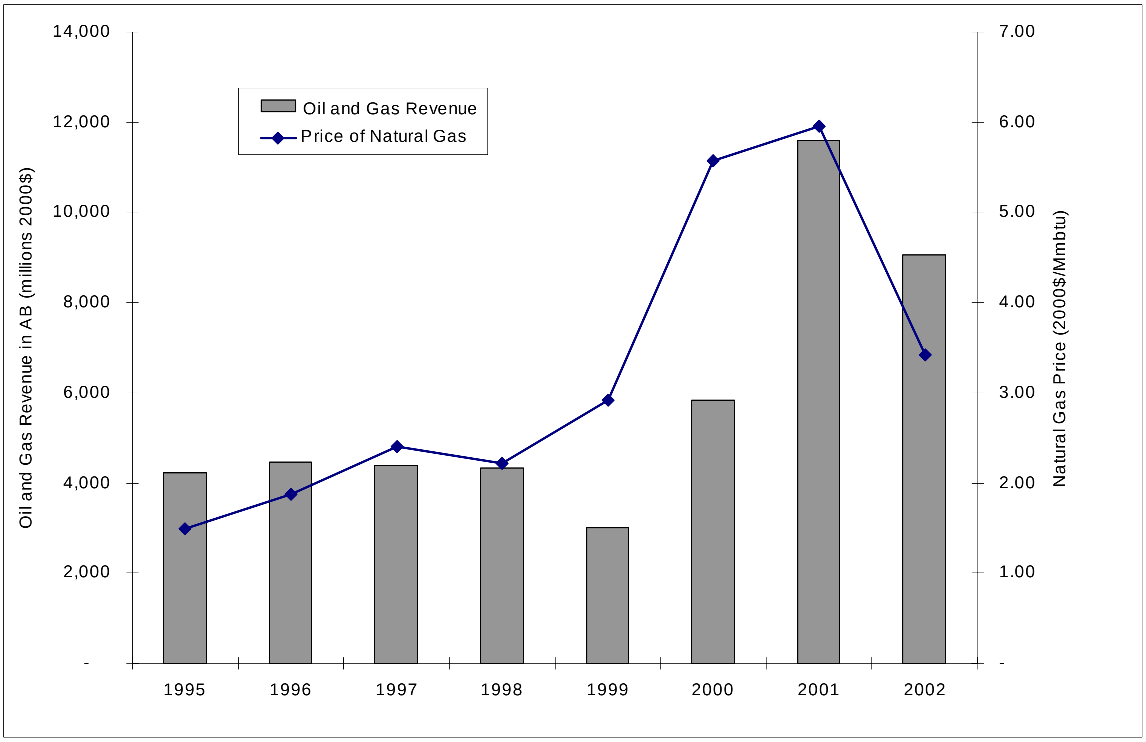

Figure 3 Trends in oil and gas revenues in Alberta and the price of natural gas (2000$), 1995 to 2002

The increase in revenue per million barrels of oil and gas production in Alberta occurred despite declining revenues from oil sands in the province. In fact, in the face of significant increases in oil sands production between 1995 and 2002 (74 percent), the Government of Alberta obtained fewer royalties per unit of oil sands production in 2002 than it did in 1995. This trend is especially important in light of the role oil sands production is expected to play in energy markets in Alberta and Canada in the future.

In terms of the amount of economic rent available in Alberta and the portion of that rent that was captured by governments, we saw a significant increase in the amount of rent available in the latter years of the study period combined with a decline in the portion of rent that the government actually captured. The government of Alberta did not capture as much of the rent available in 2002 as it did in 1995.

Between 1995 and 2002, changes in employment in the oil and gas sector did not keep pace with changes in total employment in the province. Total employment in the province increased by 22 percent between 1995 and 2002, while direct employment in oil and gas declined by 6 percent. Oil and gas GDP demonstrated the same trend. Between 1995 and 2002, total industry GDP in Alberta increased by 38 percent, while GDP from oil and gas declined by 8.5 percent.

Finally, in this chapter we have highlighted trends in environmental indicators associated with oil and gas developments in Alberta. Our analysis revealed that the area of land disturbed by wellpads from oil and gas developments in the province increased by 84 percent between 1995 and 2002. Over the same time period, the footprint from pipelines increased by 54 percent, nitrogen oxide emissions increased by 21 percent, and greenhouse gas emissions increased by 11 percent.

Oil sands production in the province poses additional serious concerns from an environmental perspective. The cumulative impact of oil sands development represents a significant surface disturbance on the landscape of Canada's boreal forest. In addition, very little land directly affected by oil sands mining operations has been restored to a state with equivalent capability to the pre-mining land, and no oil sands operations have yet received a reclamation certificate from the Government of Alberta. Emissions of nitrogen oxides and sulphur dioxide from oil sands production in Alberta have increased, and are expected to continue to increase as production expands. Finally, oil sands operations cause significant greenhouse gas emissions.

Regional Details: British Columbia

In this appendix, we describe the methods the Government of British Columbia uses to capture economic rent. We present quantitative estimates of revenues, cost of production and value of resources over the study period, and discuss the environmental impacts associated with oil and gas production in the province. We begin by providing background information on oil and gas production in British Columbia.

Background

In this section, we identify the government authorities that play a role in regulating, managing and/or facilitating oil and gas production in British Columbia. For each authority, we provide a brief description of its relevant responsibilities. We also present background information on the oil and gas sector, with figures for oil and gas production, employment in the oil and gas sector and gross domestic product associated with oil and gas production in British Columbia.

Responsible Authorities

Several government authorities in British Columbia are involved in oil and gas production in the province. Those most relevant to oil and gas developments include the following:

1. The **Ministry of Energy and Mines (MEM), Petroleum Lands Branch** is responsible for issuing and administering provincially owned petroleum and natural gas rights, as well as collecting revenues associated with the issuance of those rights. In addition, the MEM is responsible for setting policy with respect to oil and gas royalties and determining prices to be used in gas royalty calculations.
2. The **Ministry of Provincial Revenue** is responsible for administering sections of the *Petroleum and Natural Gas Act* that relate to the collection of royalties and freehold production taxes.
3. The **Oil and Gas Commission** regulates oil and gas activities and pipelines in British Columbia, reviews applications related to oil and gas activities and pipelines, encourages the participation of First Nations and Aboriginal peoples, participates in planning processes, and undertakes education and communication programs related to oil and gas developments.

Oil and Gas Production in British Columbia

British Columbia is the second-largest producer of natural gas in Canada, after Alberta. The province currently accounts for 16 percent of Canada's gas production.[1] In the face of an oil and gas exploration and development boom, the British Columbia government has proposed to double oil and gas production in the province and has implemented a number of recent policy initiatives to facilitate that expansion. These initiatives are described in detail later in this appendix.

Table 1 shows B.C. oil and gas production from 1995 to 2002, inclusive. As the figures indicate, production of both oil and gas in the province has increased significantly over the time period. Total production increased by 49 percent between 1995 and 2002. In concert with this rise in production, the province has realized an increase in

[1] Canadian Association of Petroleum Producers Web site (www.capp.ca).

- the number of oil and gas wells drilled, from 438 in 1995 to 645 in 2002;
- the number of leases awarded, from 7,809 in 1995 to 9,726 in 2002; and,
- the number of drilling licences in the province, from 1,067 in 1995 to 2,039 in 2002.[2]

While the table below shows figures up to 2002 only, it is anticipated that the increase in oil and gas production and associated activities will continue and even increase in 2003. The Petroleum Services Association of Canada forecasts record increases in drilling in British Columbia for 2003, with a predicted 46 percent increase over 2002 drilling activity.[3]

Table 1 Oil and gas production, British Columbia, 1995 to 2002 (million BOE)

PRODUCTION	1995	1996	1997	1998	1999	2000	2001	2002
Oil	121	122	131	134	137	140	161	177
Gas	19	21	23	27	21	32	32	32
Total	**140**	**143**	**155**	**161**	**158**	**172**	**194**	**209**

Source: Canadian Association of Petroleum Producers

The potential for oil and gas production in British Columbia is significant. According to the provincial government, experts estimate that there may be as much as 115 trillion cubic feet of natural gas (220 trillion barrels of oil equivalent, or BOE) and 18 billion barrels of oil yet to be discovered in British Columbia. The potential for developing offshore oil and gas resources is also significant. Total resources in west coast basins could amount to as much as 9.8 billion barrels of oil and 43.4 trillion cubic feet of gas.[4]

Oil and Gas Employment in British Columbia

Table 2 presents direct employment figures for oil and gas production in British Columbia. The table shows total employment figures for the province, as well as the share of total employment attributable to oil and gas production.

Table 2 Employment associated with oil and gas production and total employment, British Columbia, 1995 to 2002

EMPLOY'T	1995[5]	1996	1997	1998	1999	2000	2001	2002
Oil and Gas	2,514	2,563	2,777	2,053	2,077	2,597	2,194	2,525
Total	1,792,000	1,821,000	1,869,000	1,870,000	1,906,000	1,949,000	1,942,000	1,973,000
% of Total	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%

Source: 1997 to 2002 oil and gas employment figures from Statistics Canada, CANSIM Table 383-0009

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[2] *"Opening Up Oil and Gas Opportunities in BC: Statistics and Resource Potential 1992 to 2002, 2003" from* Financial and Economic Review, *July 2003.* See www.em.gov.bc.ca/subwebs/oilandgas/stat/stat.htm.

[3] Whitely, Don. "Drillers Headed to Record Year in Canada: 46% Increase Expected in BC. *Petroleum News*, Vol. 8, No. 32, 2003.

[4] Gillett, Sandy. *Oil and Gas Legacy Funding in Norway, Alaska, Alberta and BC*. Vancouver, British Columbia. 2002.

[5] Employment figures for the oil and gas sector for 1996 and 1997 were not available in the same format as the figures for 1997 to 2002 due to a change in industry classifications between 1996 and 1997 from the Standard Industry Classification System to the North American Industry Classification System. Thus, figures for employment in the oil and gas production sector for 1995 and 1996 are estimated by correlating employment with production for 1997 and extrapolating to 1995 and 1996 based on this correlation.

The figures indicate that while total employment in the province has increased (by 10 percent between 1995 and 2002), employment directly associated with oil and gas production has remained relatively steady. As a result, the portion of total employment attributable to oil and gas has declined (by 9 percent between 1995 and 2002). The trend in oil and gas employment is particularly noteworthy in light of the trend in production. Recall Table 1, which showed an increase in oil and gas production in British Columbia of 49 percent between 1995 and 2002. During the same time period, employment in this sector increased by only 0.4 percent.

Oil and Gas Gross Domestic Product in British Columbia

Table 3 presents gross domestic product (GDP) associated with oil and gas production, total provincial GDP, and oil and gas GDP as a percentage of GDP generated by all industries. The figures in the table demonstrate that the oil and gas sector's rate of growth outpaced the growth of all industries combined. While the GDP associated with oil and gas production increased by 55 percent between 1995 and 2002, "all industries" GDP increased by 18 percent over the same time period. Oil and gas GDP as a percentage of "all industries" GDP also increased between 1995 and 2002.

Table 3 GDP associated with oil and gas production and provincial GDP, British Columbia, 1995 to 2002 (million 2000$)

GDP	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas[6]	1,054	1,230	1,264	1,361	1,325	1,445	1,597	1,634
All Industries	110,695	113,164	118,032	117,711	123,096	131,086	129,757	130,148
% of Total	1.0%	1.1%	1.1%	1.2%	1.1%	1.1%	1.2%	1.3%

Source: Oil and gas figures from Statistics Canada, CANSIM Table 379-0025

Oil and Gas Revenue Generation

With the exception of a small amount of freehold production,[7] the provincial government owns all rights to petroleum and natural gas currently produced in British Columbia. Private oil and gas companies extract, process and market natural gas and oil, while the Crown reserves a portion of this production in the form of royalties. The royalty regime in British Columbia is sensitive to the age and productivity level of the well, in addition to commodity prices.

The rights to develop the province's oil and gas resources are granted to the highest bidder. Through the bidding process, oil and gas producers in British Columbia become liable for disposition bonuses. Oil and gas producers must also pay provincial and federal income taxes and federal capital taxes. The provincial capital tax rate in British Columbia was reduced to zero percent in August 2002.

Table 4 lists some key means the government uses to obtain revenues from oil and gas production on publicly owned lands in British Columbia.

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[6] The GDP figures shown here include a degree of coal manufacturing in the province.

[7] In British Columbia, "freehold" petroleum and natural gas rights stem from the fact that the Crown does not own the petroleum and natural gas rights under certain lands. Because of this, the Crown cannot include "freehold" areas in the legal description of rights being offered for disposition.

Table 4 Key means of revenue generation, British Columbia

COMPONENT	KEY ATTRIBUTES
Natural Gas Royalty	British Columbia's natural gas royalty is age- and price-sensitive. As long as the price of natural gas remains above a threshold,[8] rates increase with price. Gas is categorized as either conservation[9] or non-conservation.[10] Within non-conservation gas, gas is classified as old, new or third-tier, with royalties lowest for third-tier gas. Royalty rates for conservation gas are lower than those for non-conservation gas.
Oil Royalty	The royalty regime for oil is age- and production-sensitive. Oil is classified as old, new or third-tier, with royalties lowest for third-tier oil,[11] reflecting relatively higher costs for exploration and extraction.
Drilling Licence	Drilling licences grant the exclusive right to drill oil and gas wells in a defined area.
Disposition Bonus	For each parcel of petroleum and natural gas rights granted through the Crown sale process, companies submit bids that include an amount to cover the fees and rental, plus a disposition bonus. Bids are selected based on the highest acceptable disposition bonus for each parcel.
Permits	Permits obligate companies to conduct oil and gas exploration.
Leases	Leases allow production, in addition to providing exclusive drilling rights.
Corporate Income Tax	Between 1993 and 2001, the general corporate income tax rate in British Columbia was 16.5%. The current general rate is 13.5%.
Federal Income Tax	The net federal corporate income tax rate for oil and gas companies is 28%, against which the government allows a number of deductions.

A number of deductions and credits are available in British Columbia to encourage oil and gas production, including the gas cost allowance, the producer cost of service allowance and reduced royalties for deep and marginal wells. There are credits for coalbed methane, a royalty reduction for summer drilling programs and support for road infrastructure. Provincial oil and gas producers are also eligible for federal credit and incentive programs. The key deduction and credit programs related to oil and gas production in British Columbia are briefly described in Table 5.

[8] Called the "select price" and defined by the Minister of Energy monthly.
[9] Gas that is produced in association with oil and is conserved and marketed, rather than flared.
[10] Gas that is not conserved. This describes the vast majority of natural gas production in British Columbia.
[11] Oil produced from a pool discovered after June 1, 1998.

Table 5 Key deductions and credits related to oil and gas, British Columbia

COMPONENT	KEY ATTRIBUTES
Gas Cost Allowance (GCA)	A deduction from natural gas royalties and taxes for the cost of processing and transporting the Crown's share of gas.
Producer Cost of Service Allowance (PCOS)	A deduction from royalties for the cost of moving the royalty or tax share of gas from the wellhead to the processing plant.
Coal Bed Methane Royalty Credit	A $50,000 royalty credit for coalbed methane wells drilled up to 2008 (extended from 2004).
Summer Oil and Natural Gas Drilling Royalty Program	A credit on a portion of drilling costs incurred for wells with spud dates between March and December for 2004 and 2005.
Deep Royalty Program	A deduction for wells with a depth of at least 1,500 metres and a spud date after June 30, 2003 and before July 1, 2008.
Marginal Royalty Program	A deduction from royalties when well production is between 180 and 880 million cubic feet per day.
Road Infrastructure Program	Royalty credits of up to $30 million annually for road infrastructure related to exploration and development.
Discovery Oil Royalty Holiday	A royalty exemption for oil from a new pool discovery well for the first 36 months or 11,450 m^3, whichever comes first.
Deep Discovery Royalty Program	The lesser of either a three-year royalty holiday or 283 million cubic metres of royalty-free gas for deep discovery wells.
Deep Re-entry Royalty Program	A deduction for wells with re-entry dates after November 30, 2003 and before July 1, 2008.
Skills Development Funding	A $500,000 per year investment in skills development with matching funding by industry.
Federal Capital Cost Allowance	A deduction against income for depreciating property; Class 41 covers oil and gas equipment and allows a 25% writedown of equipment on a declining balance basis.
Federal Resource Allowance	A notional allowance in lieu of deduction of provincial royalties and freehold mineral taxes; over the study period, the deduction was 25% of taxable net resource profits.
Federal Exploration and Development Expenses	Exploratory and development expenses are grouped into one of three pools: Canadian Exploration Expenses (CEE), Canadian Development Expenses (CDE) and Canadian Oil and Gas Property Expenses (COGPE). The CEE balance of exploration expenditures is fully deductible against income, with any unclaimed portion carried forward indefinitely. Up to 30% of the CDE balance and up to 100% of the COGPE balance can be applied against income.
Federal Earned Depletion	An additional deduction from taxable income of certain exploration and development expenditures and other resource investments; the deductions for earned depletion are generally limited to 25% of the taxpayer's annual resource profits.[12]

[12] While Earned Depletion has been phased out, federal government expenditures related to it continued until 2001.

Quantitative Results of Revenue Generation

Table 6 demonstrates the trend in revenue obtained from oil and gas producers in British Columbia after all tax credits and incentive programs.[13] The sources of revenues are grouped by major category, with the main sources of revenue being disposition bonuses and oil and gas royalties. The quantity of revenue from all sources increased between 1995 and 2002, with the largest increase occurring for royalties. Total royalties from oil and gas in British Columbia increased by 466 percent between 1995 and 2002.

Table 6 Revenue from oil and gas production, British Columbia, 1995 to 2002 (million 2000$)

REVENUE SOURCE[14]	1995	1996	1997	1998	1999	2000	2001	2002
Disposition Bonuses	137	133	224	99	179	248	432	277
Natural Gas Royalty[15]	98	137	180	185	299	877	1,112	756
Oil Royalty	53	76	82	65	77	136	109	103
Income Taxes[16]	82	187	83	81	87	216	301	560
TOTAL	**371**	**532**	**569**	**430**	**643**	**1,478**	**1,954**	**1,695**

Source: "Opening Up Oil and Gas Opportunities in BC: Statistics and Resource Potential 1992 to 2002, 2003" from Financial and Economic Review, *July 2003*

To get a sense of whether the Government of British Columbia is capturing more or less revenue today than in 1995, it is necessary to take the figures for total revenue obtained and investigate them per unit of oil and gas produced. Table 7 shows revenue generation, total production (including both oil and gas in millions of barrels of oil equivalent) and revenue generation per unit of production for the province. The table demonstrates the increase in revenue per unit production as a result of the significant increase in revenues obtained in the province over the study period.

Table 7 Revenue generation and production, British Columbia, 1995 to 2002

SUMMARY	1995	1996	1997	1998	1999	2000	2001	2002
Revenue (million 2000$)	371	532	569	430	643	1,478	1,954	1,695
Production (million BOE)	140	143	155	161	158	172	194	209
Revenue/Production (2000$/BOE)	**2.6**	**3.7**	**3.7**	**2.7**	**4.1**	**8.6**	**10.1**	**8.1**

[13] Recall that this is not a complete list of all revenue sources from oil and gas, but just those that form a significant portion of economic rent capture. Other revenue sources (such as some fees) are covered in operating costs.

[14] A number of the items listed in Table 4 are grouped together in this table.

[15] Includes gas products.

[16] Includes federal and provincial income taxes.

Economic Rent in British Columbia

Table 8 presents data for the value of oil and gas resources and the cost of oil and gas production annually for the province of British Columbia. Like the revenue figures in the previous section, these figures are shown as 2000$/BOE. The value of oil and gas resources in British Columbia increased by 117 percent between 1995 and 2002. At the same time, the cost of production increased by 84 percent. Note that in years where the cost of resource production exceeded the value of the resource, no economic rent was available for capture by government.

Table 8 Resource value, production costs and economic rent (2000$/BOE), British Columbia, 1995 to 2002

	1995	1996	1997	1998	1999	2000	2001	2002
Resource Value	9.2	10.4	11.6	10.7	14.3	30.0	29.1	19.9
Production Cost	8.3	11.6	16.1	13.4	10.6	11.9	20.4	15.3
Economic Rent	0.8	0.0	0.0	0.0	3.7	18.1	8.7	4.6
Rent Capture	**100%**	**100%**	**100%**	**100%**	**100%**	**47%**	**100%**	**100%**

Source: Value figures from the Canadian Association of Petroleum Producers Statistical Handbook, Cost figures derived as per the methodology section of the report.

Trends in Associated Environmental Impacts

As the figures above demonstrate, British Columbia has realized record increases in oil and gas production in recent years. Between 1995 and 2002, oil and gas production increased by a total of 49 percent. Over the same time period, the amount of revenue obtained by the province increased by a significant 357 percent, and revenue per unit of production increased by 207 percent. This rate of increase is unprecedented in both British Columbia and Canada. This growth, however, has been accompanied by significant costs in terms of environmental impacts, including increased land disturbance and increases in acidifying and greenhouse gas emissions.

Land Disturbance

Table 9 shows the increase in the number of wells drilled each year from 1995 to 2002; in 1995 a total of 438 oil and gas wells were drilled, compared to 645 wells in 2002. Adding these annual figures to the total number of wells in existence in the province prior to 1995 provides an estimate of the number of wells in the province. Prior to 1995, there were an estimated 8,464 oil and gas wells in the province.[17] That means that with the 438 wells drilled in British Columbia in 1995, there were 8,902 wells or wellpads in the province at the end of that year. Assuming that each wellpad disturbs one hectare of land, 8,902 wellpads converts into a historical footprint of 8,902 hectares. Between 1995 and 2002, the footprint associated with wellpads in the province increased from 8,902 to 13,508 hectares, which is a 52 percent expansion of the total area of land disturbed.

[17] B.C. Oil and Gas Commission. *2002–2003 Annual Report*.

Table 9 Number of wells drilled in British Columbia, 1995 to 2002

WELLS DRILLED	1995	1996	1997	1998	1999	2000	2001	2002
Oil	65	71	109	93	38	58	75	40
Gas	234	221	213	380	405	494	594	427
Abandoned	104	118	83	113	121	137	95	68
Cased/Service[18]	35	51	178	66	56	81	111	110
Total Annual Growth	**438**	**461**	**583**	**652**	**620**	**770**	**875**	**645**
CUMULATIVE FOOTPRINT (hectares)	**8,902**	**9,363**	**9,946**	**10,598**	**11,218**	**11,988**	**12,863**	**13,508**

Source: "Opening Up Oil and Gas Opportunities in BC: Statistics and Resource Potential 1992 to 2002, 2003" from Financial and Economic Review*, July 2003*

As Table 10 demonstrates, the total length of pipelines built in British Columbia varies from year to year, with annual additions ranging from 809 kilometres constructed in 1995 to 1,953 kilometres in 1998. Prior to 1995, there were a total of 2,905 kilometres of pipelines in the province. Adding this figure to the 1995 figure reveals the total kilometres of oil and gas pipelines in British Columbia at the end of 1995: 3,714 kilometres. The cumulative figures in Table 10 clearly demonstrate the significant expansion of oil and gas pipelines in the province between 1995 and 2002, from a total of 3,714 kilometres in 1995 to a total of 13,792 kilometres in 2002. That is a 271 percent increase in the total kilometres of pipelines in the province in just seven years.

Table 10 also estimates the size of the footprint associated with oil and gas pipelines in British Columbia from 1995 to 2002. The footprint estimate is based on the average right of way for pipelines in British Columbia (15 metres), and is converted to hectares. The footprint associated with pipelines in the province has increased significantly, from 5,571 hectares in 1995 to 20,688 hectares in 2002.

Table 10 Length of pipelines completed in British Columbia, 1995 to 2002, kilometres

PIPELINES	1995	1996	1997	1998	1999	2000	2001	2002
Provincial	678	708	1,130	1,131	1,380	1,674	1,454	1,163
National Energy Board	131	246	23	822	10	50	45	242
Total	**809**	**954**	**1,153**	**1,953**	**1,390**	**1,724**	**1,499**	**1,405**
Cumulative	3,714	4,668	5,821	7,774	9,164	10,888	12,387	13,792
CUMULATIVE FOOTPRINT (hectares)	**5,571**	**7,002**	**8,731**	**11,661**	**13,746**	**16,332**	**18,580**	**20,688**

Source: B.C. Oil and Gas Commission, National Energy Board, personal communication

[18] When a steel pipe is placed in well to prevent the sides of the well from caving in, to prevent fluids from moving from one formation to another and to aid in well control.

Acidifying Emissions

In addition to land disturbances, oil and gas production in British Columbia results in the release of acidifying emissions of nitrogen oxides (NOx) and sulphur dioxide (SO_2). As Table 11 demonstrates, the expansion of oil and gas production in British Columbia has increased NOx and SO_2 emissions from oil and gas production. Oil and gas production in British Columbia resulted in 25,806 tonnes of NOx emissions in 1995 and 45,903 tonnes of NOx emissions in 2002, an increase of 78 percent. Similarly, oil and gas production in British Columbia resulted in 31,523 tonnes of SO_2 emissions in 1995 and 37,972 tonnes of SO_2 emissions in 2002, an increase of 20 percent.

Table 11 Emissions of NOx and SO_2 from the upstream oil and gas sector, British Columbia, 1995 to 2002, tonnes

EMISSION	1995	1996	1997	1998	1999	2000	2001	2002
Nitrogen Oxides	25,806	27,443	29,225	34,896	36,584	37,860	42,582	45,903
Sulphur Dioxide	31,523	33,880	54,210	46,143	32,733	31,318	35,224	37,972

Source: 1995 to 2000 figures from Clearstone Engineering, Emissions Inventories for GHG and CAC, Volume 1 and 2, produced for Canadian Association of Petroleum Producers, 2004

Greenhouse Gas Emissions

In addition to acidifying emissions, oil and gas production results in emissions of greenhouse gases. Table 12 estimates the greenhouse gas emissions (in CO_2E, or carbon dioxide equivalents) associated with the upstream oil and gas sector in British Columbia between 1995 and 2002. Greenhouse gas emissions increased between 1995 and 2002 by 47 percent.

Table 12 Upstream greenhouse gas emissions, British Columbia, 1995 to 2002, kilotonnes

EMISSION	1995	1996	1997	1998	1999	2000	2001	2002
Total CO_2E	5,905	6,313	6,518	7,041	7,093	7,183	8,079	8,709

Source: 1995 to 2000 figures from Clearstone Engineering, Emissions Inventories for GHG and CAC, Volume 1 and 2, produced for Canadian Association of Petroleum Producers, 2004

Summary

British Columbia has realized a significant increase in the amount of revenue generated from oil and gas developments in the province of late. This increase is largely the result of increased commodity prices. As Table 5 described, the royalty regime for natural gas (as well as oil) is sensitive to fluctuations in the price of fuel. Thus, when the price of natural gas increases, so, too, does the revenue the government can capture. Between 1995 and 2002, the price of oil increased by 44 percent and the price of natural gas increased by 160 percent. The greatest increases were observed between 1999 and 2000, when the international price of natural gas increased by 94 percent and the price of oil increased by 58 percent. This increase coincided with a significant increase (111 percent) in the amount of revenue per unit of production in British Columbia, as Figure 1 shows. In British Columbia we have also seen a relatively low value of resource combined with fairly high production costs resulting in a low value of economic rent and a high portion of rent capture by the government over the study period.

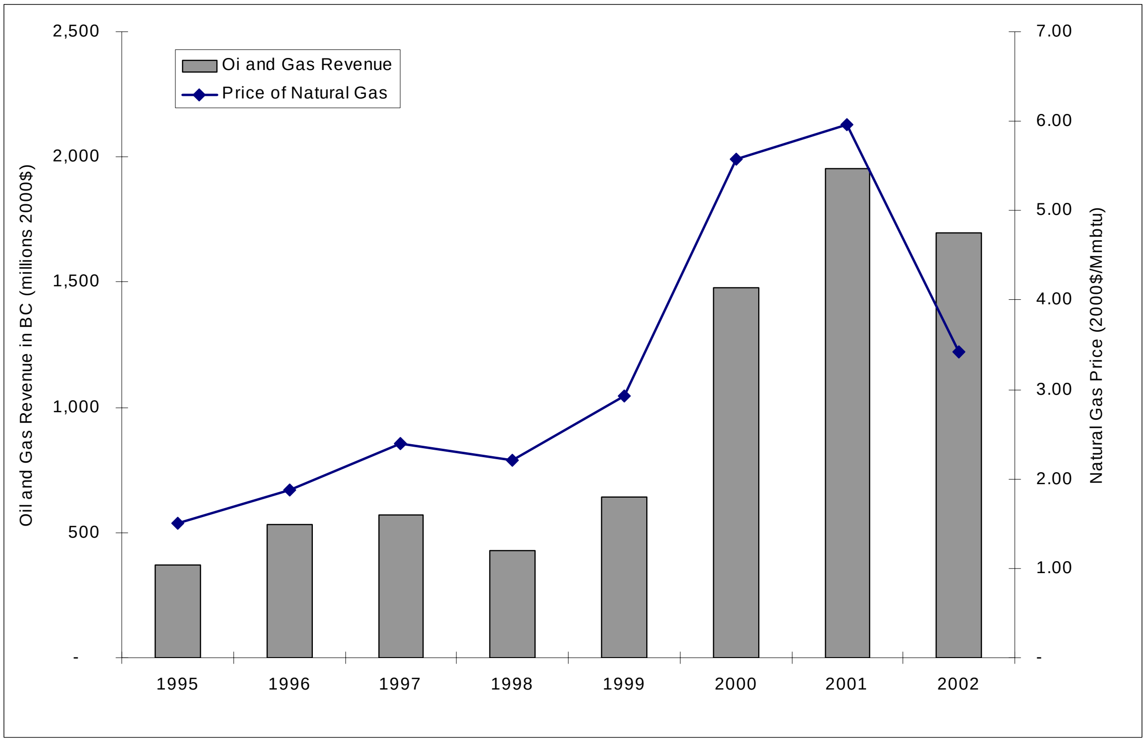

Figure 1 Trends in oil and gas revenues and the price of natural gas (2000$), 1995 to 2002

It is also worth highlighting the apparent disconnect between oil and gas production and employment in British Columbia between 1995 and 2002. While oil and gas production in the province increased by 49 percent between 1995 and 2002, direct employment in the sector increased by only 0.4 percent. This is especially interesting given recent statements by the provincial government that new oil and gas production will lead to increased employment in the province. The provincial government, in its recent energy policy, *Energy for Our Future: A Plan for BC,*[19] describes its intention to build the B.C. economy and create jobs in the province through energy developments. Investments in energy efficiency improvements and renewable energy have been shown to result in more employment than investments in conventional energy. A survey by the Pembina Institute in this area found that, on average, energy efficiency investments (e.g., building retrofits) create more than 35 person years of employment per million dollars invested.[20] That is about four times as many jobs as average levels for equivalent investments in energy supply: three times as many as alternative energy supply (e.g., solar and biomass) and five times as many as conventional energy supply (e.g., oil and gas). If the B.C. government wants to provide new employment opportunities to the citizens of the province, focusing on renewables and energy efficiency investments is more appropriate than expanding oil and gas developments.

Finally, it is important to note that while revenue generation and oil and gas production have increased in the province, so, too, have associated environmental impacts. Between 1995 and 2002:

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[19] B.C. Ministry of Energy and Mines. *Energy for Our Future: A Plan for BC*, 2002.

[20] Campbell, Barbara, Larry Dufay and Rob Macintosh. *Comparative Analysis of Employment from Air Emission Reduction Methods*. Environment Canada, 1997.

- the total number of wells drilled in the province increased by 47percent;
- the footprint from pipelines increased by 271 percent;
- emissions of nitrogen oxides increased by 78 percent;
- emissions of sulphur dioxide increased by 20 percent; and,
- greenhouse gas emissions increased by 47 percent.

According to the B.C. government, "Unclear environmental standards and inefficient regulatory processes have hindered environmentally responsible energy development in the province up to now."[21] Without government intervention, these trends will continue. This is especially worrisome in the face of several recent government initiatives designed to increase and accelerate oil and gas developments in the province. The B.C. government wants to double oil and gas production by 2010 and has implemented a number of policies[22] to help achieve this goal, without adequate safeguards for environmental protection.

[21] B.C. Ministry of Energy and Mines. *Energy for Our Future: A Plan for BC*, 2002.

[22] These initiatives are described in Table 5, and include a royalty credit for coalbed methane production, a summer drilling royalty credit, deep and marginal well royalty reductions, and a road infrastructure tax credit.

Regional Details: Saskatchewan

Oil and gas production in Saskatchewan has increased significantly in recent years, and revenues associated with oil and gas production represent a growing share of total provincial revenues. As this revenue source becomes more significant, it is important to consider the long-term stability of both the economic and environmental situations in Saskatchewan. In this appendix, we describe the methods the Government of Saskatchewan uses to capture revenues from oil and gas production in the province. We also present quantitative estimates of revenues, costs and the value of oil and gas resources over the study period, and discuss the environmental impacts associated with oil and gas production in the province. We begin with background information on oil and gas production in Saskatchewan.

Background

In this section, we identify the government authorities that play a role in regulating, managing and/or facilitating oil and gas production in Saskatchewan. For each authority, we provide a brief description of its relevant responsibilities. We also present background information on the oil and gas sector, with figures for oil and gas production, employment in the oil and gas sector and gross domestic product associated with oil and gas production in Saskatchewan.

Responsible Authorities

One key department, the Department of Industry and Resources, has authority over oil and gas developments in Saskatchewan. This department has several divisions focused on different aspects of the regulation, management and promotion of oil and gas production in the province.

1. The **Department of Industry and Resources** co-ordinates, develops, promotes and implements policies and programs with the goal of strengthening and diversifying the Saskatchewan economy.
2. The **Industry Development Division** of the **Department of Industry and Resources** assists and attracts new, existing and expanding businesses, co-operatives and entrepreneurs to create and/or expand business activity in the province, and facilitates the development and capacity enhancement of community economic development organizations.
3. The **Strategic Sector Development Branch** of the **Industry Development Division** facilitates the growth and development of the province's oil and gas sector, among other sectors.
4. The **Geology and Petroleum Lands Branch** of the **Department of Industry and Resources** administers oil and gas dispositions.

Oil and Gas Production in Saskatchewan

Saskatchewan is Canada's second-largest producer of oil, currently accounting for almost 18 percent of the country's total production. The provincial Crown owns 25.3 million hectares of oil and natural gas rights in the surveyed area of the province. This represents about 78 percent of total provincial rights, of which about 6.6 million hectares (or 20 percent of the total provincial petroleum and natural gas rights) are currently leased to oil and gas companies.[1] Oil production in Saskatchewan has almost doubled in the last 10 years.[2] More recently, the focus of new

[1] See www.ir.gov.sk.ca/Default.aspx?DN=3659,3384,2936,Documents.

[2] Canadian Association of Petroleum Producers Web site. See www.capp.ca.

development in Saskatchewan has shifted from oil to natural gas. As Table 1 demonstrates, between 1995 and 2002 oil production declined by 11 percent, while over the same time period natural gas production increased by 31 percent.

Table 1 Oil and gas production, Saskatchewan, 1995 to 2002 (million BOE)

PRODUCTION	1995	1996	1997	1998	1999	2000	2001	2002
Oil	47	41	39	39	41	42	42	42
Gas	119	133	148	147	139	154	158	155
Total	**166**	**173**	**187**	**187**	**180**	**196**	**200**	**197**

Source: Canadian Association of Petroleum Producers

Oil and Gas Employment in Saskatchewan

Table 2 presents direct employment figures for oil and gas production in Saskatchewan. The table shows total employment figures for the province, as well as the share of total employment attributable to the oil and gas sector. The figures indicate that increases in employment associated with oil and gas production have outpaced increases in total employment in the province. Indeed, between 1995 and 2002, while total employment in Saskatchewan increased by 5 percent, employment directly associated with oil and gas production increased by 20 percent.

Table 2 Employment associated with oil and gas production and total employment, Saskatchewan, 1995 to 2002

EMPLOY'T	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas	1,912	2,000	2,164	2,279	1,919	1,968	2,781	2,289
Total	459,000	458,000	470,000	476,000	480,000	485,000	472,000	482,000
% of Total	0.4%	0.4%	0.5%	0.5%	0.4%	0.4%	0.6%	0.5%

Source: 1997 to 2002 oil and gas employment figures from Statistics Canada, CANSIM Table 383-0009

Oil and Gas Gross Domestic Product in Saskatchewan

Table 3 presents gross domestic product (GDP) associated with oil and gas production, total provincial GDP, and oil and gas GDP as a percentage of GDP generated by all industries. The figures in the table demonstrate that the growth of all industries combined has outpaced the growth of the oil and gas sector quite significantly. Between 1995 and 2002, GDP associated with oil and gas production declined by 11 percent. Over the same period, “all industries” GDP increased by 13 percent. Oil and gas GDP as a percentage of “all industries” GDP declined by 22 percent between 1995 and 2002. These figures indicate that oil and gas production constitutes a declining portion of the total economy in Saskatchewan.

Table 3 GDP associated with oil and gas production and provincial GDP, Saskatchewan, 1995 to 2002 (million 2000$)

GDP	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas[3]	2,190	2,209	2,429	2,858	2,264	1,973	2,068	1,942
All Industries	28,847	31,017	30,849	30,845	31,514	33,704	32,575	32,634
% of Total	7.6%	7.1%	7.9%	9.3%	7.2%	5.9%	6.3%	6.0%

Source: Oil and gas figures from Statistics Canada, CANSIM Table 379-0025

Oil and Gas Revenue Generation

The provincial Crown owns approximately 78 percent of all petroleum and natural gas rights in Saskatchewan. Freehold lands comprise 18.5 percent, Indian reserves hold 2 percent, and the remaining 1.5 percent is held under federal jurisdiction.

Dispositions of Crown petroleum and natural gas rights can be purchased at Crown land sales, which are held six times each year. Once rights to produce oil and gas in Saskatchewan have been granted, the government collects royalties on the oil and gas production that takes place. Royalties in Saskatchewan vary with price, age and productivity. Oil and gas producers in Saskatchewan are also liable for provincial and federal income taxes. Table 4 lists the taxes and royalties the Saskatchewan government uses to obtain revenues from oil and gas production in the province.

Table 4 Key means of revenue generation, Saskatchewan

COMPONENT	KEY ATTRIBUTES
Natural Gas Royalty	Natural gas in Saskatchewan is considered either non-associated or associated. Within each of these categories, for the purposes of royalty calculations, gas is classified as fourth-tier, third-tier, new or old. Royalty rates in Saskatchewan are price-sensitive. Below a threshold price,[4] a base royalty rate applies. Above that threshold, royalty rates increase with prices.
Associated Natural Gas Royalty Regime	A royalty is payable on associated natural gas produced from an oil well that exceeds approximately 65,000,000 m^3/month. The royalty rates are based on the fourth-tier natural gas royalty structures.
Crude Oil Royalty	Crude oil in Saskatchewan is considered either heavy oil, southwest-designated oil, or non-heavy oil. Within each of these categories, oil is classified as fourth-tier, third-tier, old or new. Royalty rates are lowest for fourth-tier oil.
Helium and Associated Gases Royalty	This royalty is determined by applying a Crown royalty rate to helium and associated gases produced from each well.
Corporate Income Tax	The current income tax rate is 17% of taxable income earned in Saskatchewan.
Royalty/Tax Program for High Water-Cut Oil Wells	High water-cut oil resulting from qualifying investments made to rejuvenate oil wells and/or associated facilities receive "third-tier oil" Crown royalty rates with a Saskatchewan Resource Credit of 2.5%.

[3] Includes coal manufacturing.

[4] Established by the Minister of Industry and Resources monthly.

Table 4 Continued

COMPONENT	KEY ATTRIBUTES
Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects	Incremental waterflood oil produced from an approved waterflood project qualifies for "fourth-tier oil" Crown royalty rates. Incremental waterflood oil does not qualify for a royalty incentive volume.
Federal Income Tax	The net federal corporate income tax rate for oil and gas companies is 28%, against which the government allows a number of deductions.

Oil and gas producers in Saskatchewan can take advantage of a number of deductions and credit programs that encourage and facilitate oil and gas production in the province, including the Saskatchewan Resource Credit. A number of changes to the royalty regime governing oil and gas production in Saskatchewan were announced in 2002. These changes include new lower royalty structures and a new system of volume incentives. In addition, a new royalty regime for gas produced from new oil wells was introduced, and incentives were introduced for horizontal and deep wells.[5] Provincial oil and gas producers are also eligible for federal credit and incentive programs. These and other key programs are described in Table 5.

Table 5 Key deductions and credits related to oil and gas, Saskatchewan

COMPONENT	KEY ATTRIBUTES
Saskatchewan Resource Credit	A credit against royalty and freehold production tax rates, which can reduce royalty rates to 0%.
Royalty Tax Regime Applicable to Enhanced Oil Recovery Projects	A calculation that determines royalty and tax rates on a profitability basis, both before and after payout of the project.
Royalty/Tax Incentive Volumes for Vertical Oil Wells[6]	An incentive volume for qualifying vertical oil wells.
Royalty/Tax Incentive Volume for Horizontal Oil Wells	An incentive volume for qualifying horizontal oil wells.
Exploratory Gas Wells	An incentive volume for wells that qualify as exploratory gas wells.
Low Productivity Wells Royalty Rate	A fiscal regime that does not subject wells producing at rates less than about 23 m^3/month to a royalty.
Low Productivity Wells Freehold Tax Rate	A low productivity tax reduction that can be applied against freehold taxes.
Oil Well Reactivation Program	A program targeting oil production from reactivated oil wells, which are subject to a maximum royalty rate of 5% less the Saskatchewan Resource Credit.
Federal Capital Cost Allowance	A deduction against income for depreciating property; Class 41 covers oil and gas equipment and allows a 25% writedown on equipment on a declining balance basis.

[5] Government of Saskatchewan. *Economic News: Royalty and Tax Changes to Stimulate Oil and Gas*, 2002. See www.wideopenfuture.ca/news-2002-10-07.html.

[6] Non-deep vertical development oil wells and development gas wells are not eligible for any incentive volume.

Table 5 Continued

COMPONENT	KEY ATTRIBUTES
Federal Resource Allowance	A notional allowance in lieu of deduction of provincial royalties and freehold mineral taxes; over the study period, the deduction was equal to 25% of taxable net resource profits.
Federal Exploration and Development Expenses	Exploratory and development expenses are grouped into one of three pools: Canadian Exploration Expenses (CEE), Canadian Development Expenses (CDE), and Canadian Oil and Gas Property Expenses (COGPE). The CEE balance of exploration expenditures is fully deductible against income, with any unclaimed portion carried forward indefinitely. Up to 30% of the CDE balance and up to 100% of the COGPE balance can be applied against income.
Federal Earned Depletion	An additional deduction from taxable income of certain exploration and development expenditures and other resource investments. The deductions for earned depletion are generally limited to 25% of the taxpayer's annual resource profits. [7]

Quantitative Results of Revenue Generation

Table 6 demonstrates the trend in revenues obtained from oil and gas producers in Saskatchewan. The major sources of revenue are royalties, especially oil royalties and income taxes. Total revenues increased by 56 percent between 1995 and 2002.

Table 6 Revenue from oil and gas production, Saskatchewan, 1995 to 2002 (million 2000$)

REVENUE SOURCE [8]	1995	1996	1997	1998	1999	2000	2001	2002
Oil Royalty	577	479	731	510	313	640	775	524
Natural Gas Royalty	67	44	56	46	68	92	232	122
Income Taxes[9]	101	233	103	95	100	247	307	520
TOTAL	**745**	**757**	**890**	**651**	**480**	**979**	**1,314**	**1,166**

Table 7 compares trends in revenue with production to determine if the Government of Saskatchewan is capturing more or less revenue today than in 1995. The figures in the table show that both revenue and production increased between 1995 and 2002. Revenue increased by 56 percent and production increased by 19 percent. Over the same period, revenue per unit of production increased by 32 percent, from $4.5/BOE to $5.9/BOE.

[7] While Earned Depletion has been phased out, federal government expenditures related to it continued until 2001.

[8] A number of the items presented in Table 6-4 are combined for the purposes of this table.

[9] Includes federal and provincial income taxes.

Table 7 Revenue generation and production, Saskatchewan, 1995 to 2002

SUMMARY	1995	1996	1997	1998	1999	2000	2001	2002
Revenue (million 2000$)	745	757	890	651	480	979	1,314	1,166
Production (million BOE)	166	173	187	187	180	196	200	197
Revenue/Production (2000$/BOE)	**4.5**	**4.4**	**4.7**	**3.5**	**2.7**	**5.0**	**6.6**	**5.9**

Economic Rent in Saskatchewan

Table 8 presents data for the value of oil and gas resources and the cost of oil and gas production annually for the province of Saskatchewan. Figures are shown as 2000$/BOE, like the revenue figures in the previous section. The value of oil and gas resources in Saskatchewan increased by 27 percent between 1995 and 2002. At the same time, the cost of production increased by 68 percent. Economic rent was available for capture by the Saskatchewan government in every year over the study period. The rate of rent capture ranged from a low of 23% in 2000 to a high of 100% in 1997 and 1998.

Table 8 Resource value, production costs and economic rent (2000$/BOE), Saskatchewan, 1995 to 2002

	1995	1996	1997	1998	1999	2000	2001	2002
Resource Value	17.7	21.5	19.1	13.5	21.5	31.7	25.1	22.5
Production Cost	8.7	12.9	14.6	11.6	16.8	10.3	12.0	14.6
Economic Rent	9.0	8.6	4.5	1.8	4.6	21.5	13.1	7.9
Rent Capture	**50%**	**51%**	**100%**	**100%**	**58%**	**23%**	**50%**	**75%**

Source: Value figures from the Canadian Association of Petroleum Producers Statistical Handbook, Cost figures derived as per the methodology section of the report.

Trends in Associated Environmental Impacts

As the figures above demonstrate, in recent years Saskatchewan has experienced an increase in oil and gas production. Between 1995 and 2002, oil and gas production combined expanded by a total of 19 percent. Over the same time period, the amount of revenue captured by the province increased by 56 percent, and revenue per unit of production increased by 31 percent. This growth has been accompanied by environmental impacts in many forms, including disturbance of wildlife habitat due to well drilling and pipeline construction, and acidifying emissions and greenhouse gas emissions.

Land Disturbance

Table 9 shows the increase in the number of wells drilled each year from 1995 to 2002; in 1995 a total of 2,092 oil and gas wells were drilled, compared to 3,401 wells in 2002. Adding these annual figures to the total number of wells in existence in the province prior to 1995 provides an estimate of the total number of wells in the province. Prior to 1995, there were an estimated 50,557 oil and gas wells in Saskatchewan.[10] This means that with the 2,092 wells drilled in Saskatchewan in 1995, there were a total of 52,649 wells or wellpads in the province at the end of that year. Assuming one hectare of disturbance for each wellpad, 52,649 hectares of land is

[10] Saskatchewan Department of Industry and Resources. *Mineral Statistics Handbook*, 2001.

disturbed in Saskatchewan by oil and gas wellpads. Between 1995 and 2002, the footprint associated with wellpads in the province increased from 52,649 to 74,105 hectares. That 41 percent increase in the amount of land disturbed by oil and gas wellpads in the province occurred in just seven years.

Table 9 Number of wells drilled in Saskatchewan, 1995 to 2002

WELLS DRILLED	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
Oil	1,550	2,039	3,059	908	1,298	2,330	1,954	1,489
Gas	210	307	248	567	990	1,160	1,372	1,713
Abandoned and Suspended	332	518	525	202	185	210	183	199
Total Annual Growth	**2,092**	**2,864**	**3,832**	**1,677**	**2,473**	**3,700**	**3,509**	**3,401**
CUMULATIVE FOOTPRINT (hectares)	**52,649**	**55,513**	**59,345**	**61,022**	**63,495**	**67,195**	**70,704**	**74,105**

Source: Saskatchewan Industry and Resources, Mineral Statistics Yearbook

The trend in the table above is expected to continue. Saskatchewan anticipated record drilling activity in 2003, with a total of 3,900 wells drilled,[11] compared to 3,401 wells drilled in 2002. Table 10 shows the total length of all pipelines built in Saskatchewan each year from 1995 to 2002. Prior to 1995, there were 17,837 kilometres of pipelines in the province. Adding this figure to the 1995 figure reveals the total kilometres of oil and gas pipelines in Saskatchewan at the end of 1995: 18,133 kilometres. The cumulative figures in Table 10 demonstrate the expansion of oil and gas pipelines in the province between 1995 and 2002, from a total of 18,133 kilometres in 1995 to a total of 21,125 kilometres in 2002. That is a 17 percent increase in the total kilometres of pipelines in the province over seven years.

Table 10 also estimates the size of the footprint associated with oil and gas pipelines in Saskatchewan from 1995 to 2002. The footprint estimate is based on the average right of way for pipelines in British Columbia (15 metres). The footprint associated with pipelines in Saskatchewan has increased from 27,199 hectares in 1995 to 31,687 hectares in 2002.

Table 10 Length of pipelines completed in Saskatchewan, 1995 to 2002, kilometres

PIPELINES	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
Provincial	296	410	395	92	153	133	267	232
National Energy Board	-	89	231	795	1	-	194	-
Total	**296**	**499**	**626**	**887**	**154**	**133**	**461**	**232**
Cumulative	18,133	18,632	19,258	20,145	20,299	20,432	20,893	21,125
CUMULATIVE FOOTPRINT (hectares)	**27,199**	**27,948**	**28,887**	**30,217**	**30,448**	**30,648**	**31,339**	**31,687**

Source: Alberta Energy Utilities Board Statistical Series 57, National Energy Board, personal communication

[11] Whiteley, Don. "Drillers Headed to Record Year in Canada; 46% Increase Expected in BC." *Petroleum News*, Vol. 8, No. 32, 2003.

Acidifying Emissions

In addition to land disturbances, oil and gas production in Saskatchewan results in the release of acidifying emissions of nitrogen oxides (NOx) and sulphur dioxide (SO_2). Between 1995 and 2002, emissions of nitrogen oxides and sulphur dioxide increased by 8 percent and 37 percent, respectively.

Table 11 Emissions of NOx and SO_2 from the upstream oil and gas sector, Saskatchewan, 1995 to 2002, tonnes

EMISSION	1995	1996	1997	1998	1999	2000	2001	2002
Nitrogen Oxides	13,423	12,494	13,353	13,314	13,584	14,467	14,731	14,536
Sulphur Dioxide	5,281	7,202	7,932	8,962	7,177	7,214	7,346	7,249

Source: 1995 to 2000 data from Clearstone Engineering, Emissions Inventories for GHG and CAC, Volume 1 and 2, produced for Canadian Association of Petroleum Producers, 2004

Greenhouse Gas Emissions

In addition to acidifying emissions, oil and gas production results in emissions of greenhouse gases. Table 12 estimates the greenhouse gases (in carbon dioxide equivalents) associated with upstream oil and gas emissions in Saskatchewan between 1995 and 2002. Greenhouse gas emissions associated with oil and gas production in Saskatchewan increased by 58 percent between 1995 and 2002.

Table 12 Upstream greenhouse gas emissions, Saskatchewan, 1995 to 2002, kilotonnes

EMISSION	1995	1996	1997	1998	1999	2000	2001	2002
CO_2E	9,857	10,648	12,746	12,759	12,859	15,161	15,777	15,568

Source: 1995 to 2000 data from Clearstone Engineering, Emissions Inventories for GHG and CAC, Volume 1 and 2, produced for Canadian Association of Petroleum Producers, 2004

Summary

As was the case in both British Columbia and Alberta, the increase in revenue per unit of oil and gas production in Saskatchewan between 1995 and 2002 is largely the result of increased commodity prices. Between 1995 and 2002, the price of natural gas increased by 160 percent and the price of oil increased by 44 percent (see Figure 1). Because the increase in the price of oil over the study period was not as significant as the increase in the price of natural gas, and because the focus in Saskatchewan is on oil rather than natural gas, the increase in the amount of revenue generated in Saskatchewan was not as extreme as in British Columbia and Alberta (regions that focus more on natural gas developments). Specifically, revenue per unit of production in British Columbia increased by 207 percent between 1995 and 2002, while it increased by 117 percent in Alberta and by just 31 percent in Saskatchewan in the same period.

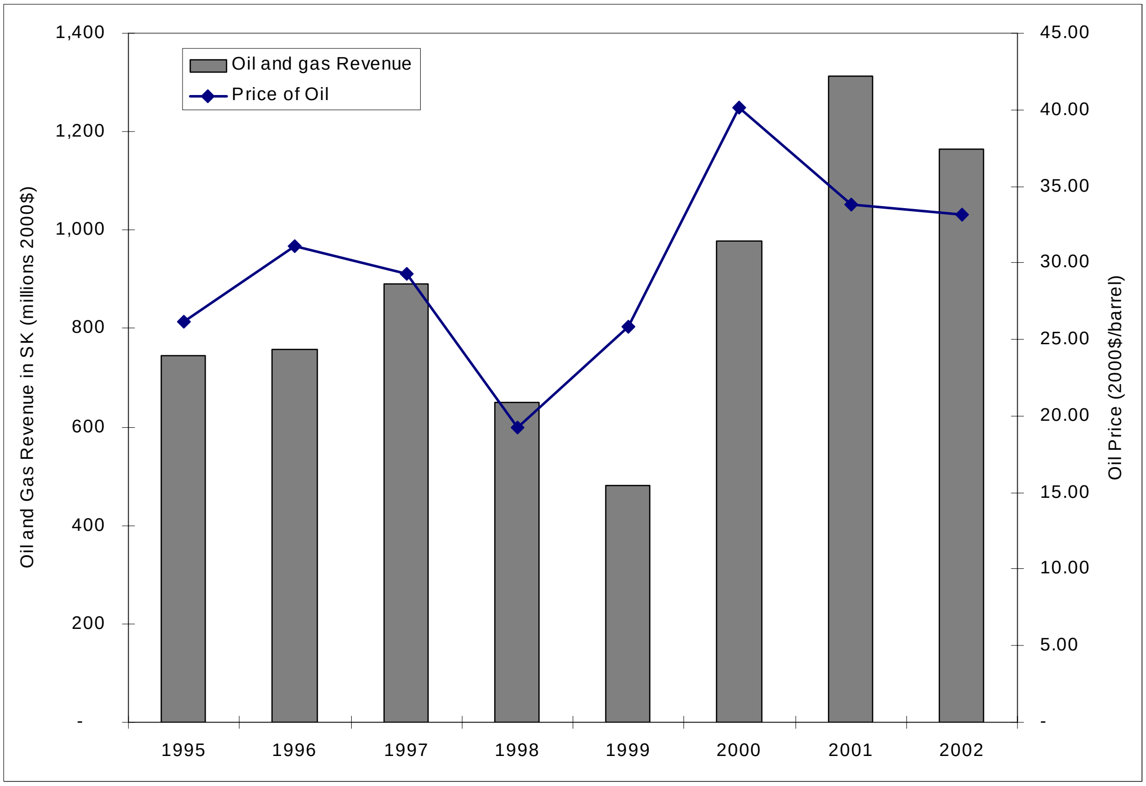

Figure 1 Trends in oil and gas revenues in Saskatchewan and the price of oil (2000$), 1995 to 2002

In every year over the study period, economic rent was available for capture by the Saskatchewan Government. In 1997 and 1998, the government managed to capture the maximum amount of rent available (100%). In other years, the government left economic rent in the hands of industry as excess profits.

As petroleum production in Saskatchewan has increased, so, too, have the associated environmental impacts. Between 1995 and 2002, Saskatchewan saw an increase in the amount of land disturbed by wellpads (41 percent) and by pipelines (17 percent). Other environmental effects include an increase in NOx emissions of 8 percent, an increase of SO_2 emissions of 37 percent, and an increase in greenhouse gas emissions from oil and gas production of 58 percent.

Finally, it is worth noting that in October 2002, the premier of Saskatchewan announced a number of major changes to the Crown royalty and freehold production tax structures, as well as the Corporation Capital Tax Surcharge rate that applies to production from new oil and gas exploration and development activity in the province. Specifically, the following initiatives were introduced:

1. A new, lower "fourth-tier" production and price-sensitive Crown royalty structure for oil and gas production on or after October 1, 2002;
2. A reduction in the Corporation Capital Tax Surcharge rate from 3.6 percent to 2.0 percent for oil and gas production;
3. A system of volume-related incentives and maximum royalty rates that apply to initial production from oil and gas wells with a finished drilling date on or after October 1, 2002; and,

4. Application of the "fourth-tier" royalty regime to re-entry and short section horizontal oil wells with a finished drilling date on or after October 1, 2002.

It remains to be seen whether the above initiatives will lead to a higher or lower rate of rent capture in the province of Saskatchewan.

Addendum

Since its initial release on August 17, 2004, the following changes have been identified and should be made to this document; incorrect text in bold and new or revised text is in italics.

Regional Details: Northwest Territories, page 10:

- Sentence reads: However, an analysis of wells in the Deh Cho First Nation territory revealed that all producing wells are less than **6** kilometres north of the Northwest Territories border.
- Sentence should read: However, an analysis of wells in the Deh Cho First Nation territory revealed that all producing wells are less than *60* kilometres north of the Northwest Territories border.
- The proper reference for this sentence is: *Petr Cizek. Value of Deh Cho Oil and Gas Production and Royalties. Prepared for Deh Cho First Nations, August 18, 2003.*

This NWT appendix has been updated to reflect these changes.

Regional Details: Northwest Territories

The regulation and management of oil and gas production in the Northwest Territories is the responsibility of the federal government. The federal government owns and manages more than 90 percent of petroleum rights in the Northwest Territories. As such, the federal government administers and collects royalties and taxes associated with oil and gas production in the region. In this appendix, we describe the methods the federal government uses to obtain revenues from oil and gas production in the territory. We present quantitative estimates of revenues as well as cost and resource value figures over the study period, and discuss environmental impacts associated with oil and gas production in the territory. We begin with background information on oil and gas production in the Northwest Territories.

Background

In this section, we identify the government authorities that play a role in regulating, managing and/or facilitating oil and gas production in the Northwest Territories. For each authority, we provide a brief description of its relevant responsibilities. We also present background information on the oil and gas sector, with figures for oil and gas production, employment in the oil and gas sector and gross domestic product associated with oil and gas production in the Northwest Territories.

Responsible Authorities

The federal government is currently responsible for managing petroleum rights, issuing licences, and setting and collecting oil and gas royalties for subsurface rights in the Northwest Territories.[1] In contrast to Yukon Territory, where a devolution process transferred regulatory power over oil and gas production to the Yukon government, in the Northwest Territories regulation of oil and gas production is being transferred on a region-by-region basis. Aboriginal governments that have settled land claims are responsible for their own petroleum subsurface rights and are thus able to levy royalties on relevant oil and gas developments.[2] Within the federal government, the management of oil and gas resources on Crown land is the joint responsibility of the following departments:

1. The **Northern Oil and Gas Directorate** of the **Department of Indian Affairs and Northern Development (DIAND)**[3] administers the *Canada Petroleum Resources Act*. The *Canada Petroleum Resources Act* governs the allocation of Crown lands to the private sector, tenure to the allocated rights, and the setting and collection of royalties.
2. The **National Energy Board** administers the *Canada Oil and Gas Operations Act*. The *Canada Oil and Gas Operations Act* regulates industrial activities with respect to resource conservation, environmental protection and the safety of workers.

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[1] See www.gov.nt.ca/RWED/mog/oil_gas/issues.htm.

[2] Op. cit.

[3] The Department of Indian Affairs and Northern Development (DIAND) has changed its name to Indian and Northern Affairs Canada (INAC). In this report, we use the old name and abbreviation, DIAND, because many people are familiar with that name and because the legislation that set up the department has not been changed, so the Minister is still officially the Minister of DIAND. However, the federal government prefers to identify the department by its new name, Indian and Northern Affairs Canada (INAC).

Oil and Gas Production in the Northwest Territories

Rising gas prices, combined with a number of First Nations land claim settlements in the last decade, have renewed interest in oil and gas exploration in the Northwest Territories. The petroleum-bearing areas of the territory are located in, but not restricted to, the western Northwest Territories, stretching from the Deh Cho at the Alberta–Northwest Territories border to the Mackenzie Delta/Beaufort Sea, and on to the Sverdrup Basin near Melville Island. Oil production from the Norman Wells oil field has been taking place since 1943. An expansion in 1985 and the completion of a pipeline to Zama, Alberta, have enabled the well to operate at full potential in recent years. Large natural gas discoveries on the Liard Plateau, which is well connected to southern markets by pipelines, are resulting in initial production rates of up to 50 million cubic feet per day.[4] In 2000, the federal government made new lands available for exploration in the Mackenzie Delta/Beaufort Sea. The oil and gas industry responded quickly with bids totaling roughly $400 million and work commitments of $1 billion.[5] A consortium of oil and gas companies[6] filed a Preliminary Information Package for a Mackenzie Gas Project in the spring of 2003, which outlines plans for developing sweet natural gas from three onshore natural gas fields in the Mackenzie Delta and transporting it to market by pipeline. Combined, the three developments account for 164 billion m^3 (Gm^3) or 5.8 trillion cubic feet (Tcf) of natural gas. If the project proceeds, it is expected that other onshore and offshore sources of natural gas will be developed and “tied in” to the pipeline.

Table 1 shows oil and gas production from 1995 to 2002, inclusive. As the figures indicate, oil production has remained relatively constant over the study period, while gas production has increased. Total production in the territory increased by 14 percent between 1995 and 2002, but remains relatively low compared to the expected growth if the Mackenzie Gas Project proceeds.

Table 1 Oil and gas production, Northwest Territories, 1995 to 2002, million BOE

PRODUCTION	1995	1996	1997	1998	1999	2000	2001	2002
Oil	11	10	10	10	10	9	9	9
Gas	1	1	1	1	0	3	6	5
Total	**12**	**11**	**11**	**11**	**10**	**12**	**15**	**14**

Source: Canadian Association of Petroleum Producers and Statistics Canada

Oil and Gas Employment in the Northwest Territories

Table 2 presents direct employment figures for oil and gas production in the Northwest Territories from 1995 to 2002.[7] The table shows total employment figures for the territory, as well as the share of total employment attributable to oil and gas production. The figures indicate that both total employment and employment associated with oil and gas production increased between 1995 and 2002, by 11 percent each. The share of total employment attributable to oil and gas production remained the same between 1995 and 2002.

4 See www.gov.nt.ca/RWED/mog/oil_gas/history.htm.
5 Op. cit.
6 Imperial Oil, Aboriginal Pipeline Group, ConocoPhillips, Shell Canada, ExxonMobil.
7 Employment figures prior to 1999 include Nunavut.

Table 2 Employment associated with oil and gas production and total employment, Northwest Territories, 1995 to 2002

EMPLOY'T	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas	436	416	399	388	352	409	497	476
Total	23,617	24,952	25,314	25,344	21,397	21,874	24,257	25,993
% of Total	2%	2%	2%	2%	2%	2%	2%	2%

Source: Statistics Canada, CANSIM Table 383-0009

Oil and Gas Gross Domestic Product in the Northwest Territories

Table 3 presents gross domestic product (GDP) associated with oil and gas production, total provincial GDP, and oil and gas GDP as a percentage of GDP generated by all industries. The figures in the table demonstrate that between 1995 and 2002, the oil and gas sector in the Northwest Territories constituted a slightly declining share of "all industries" GDP in the territory. Indeed, between 1995 and 2002, GDP associated with oil and gas declined by 36 percent, while "all industries" GDP increased by 13 percent.[8]

Table 3 GDP associated with oil and gas production and territorial GDP, Northwest Territories, 1995 to 2002 (million 2000$)

GDP	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas[9]	218	208	199	186	132	195	216	170
All Industries	2,730	2,870	2,813	2,716	2,398	2,580	2,966	3,031
% of Total	8%	7%	7%	7%	6%	8%	7%	6%

Source: Oil and gas figures from Statistics Canada, CANSIM Table 379-0025

Oil and Gas Revenue Generation

The Government of Canada issues rights to oil and gas companies to produce oil and gas resources in the Northwest Territories. Rights are granted through a competitive bidding process, which begins with a call for nominations through which industry specifies blocks of land of particular interest. Crown rights are then issued through an open, competitive bidding process. Once rights are issued, in the form of an Exploration Licence or a Production Licence, the government collects royalties and other fees from oil and gas producers. Table 4 lists the fees collected by the federal and territorial governments in return for the right to develop oil and gas resources in the Northwest Territories.

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[8] The increase in "all industries" GDP is largely due to increased diamond mine activities in the Northwest Territories over this period.

[9] Includes a degree of coal manufacturing.

Table 4 Key means of revenue generation, Northwest Territories

COMPONENT	KEY ATTRIBUTES
Royalties	The royalty regime governing oil and gas developments in the Northwest Territories features royalty rates starting at 1% and rising by 1% every 18 months, to a maximum of 5%, until project payout. After project payout, royalties are capped at the greater of 30% of net revenues or 5% of gross revenues.
Licences	Licences are issued following a call for bids in which the highest bidder receives rights to blocks of land.
Corporate Income Tax	The corporate income tax rate in the Northwest Territories is 14.0%.
Federal Income Tax	The net federal corporate income tax rate for oil and gas companies is 28%, against which the government allows a number of deductions.

Several deductions and credits are available to oil and gas producers in the Northwest Territories. These are briefly described in Table 5.

Table 5 Key deductions and credits related to oil and gas, Northwest Territories

COMPONENT	KEY ATTRIBUTES
Federal Capital Cost Allowance	A deduction against income for depreciating property; Class 41 covers oil and gas equipment and allows a 25% writedown on equipment on a declining balance basis.
Federal Resource Allowance	A notional allowance in lieu of deduction of provincial royalties and freehold mineral taxes; over the study period, the deduction was 25% of taxable net resource profits.
Federal Exploration and Development Expenses	Exploratory and development expenses are grouped into one of three pools: Canadian Exploration Expenses (CEE), Canadian Development Expenses (CDE), and Canadian Oil and Gas Property Expenses (COGPE). The CEE balance of exploration expenditures is fully deductible against income, with any unclaimed portion carried forward indefinitely. Up to 30% of the CDE balance and up to 100% of the COGPE balance can be applied against income.
Federal Earned Depletion	An additional deduction from taxable income of certain exploration and development expenditures and other resource investments. The deductions for earned depletion are generally limited to 25% of the taxpayer's annual resource profits. [10]

Quantitative Results of Revenue Generation

Table 6 demonstrates the trend in revenues obtained from oil and gas producers in the Northwest Territories. The major sources of revenue are royalties and income taxes. Total revenues increased by 335 percent between 1995 and 2002.

[10] While Earned Depletion has been phased out, federal government expenditures related to it continued until 2001.

Table 6 Revenue from oil and gas production, Northwest Territories, 1995 to 2002 (million 2000$)

REVENUE SOURCE	1995	1996	1997	1998	1999	2000	2001	2002
Royalties	7.3	15.7	13.7	7.8	7.8	11.5	15.5	27.9
Income Taxes[11]	7.1	15.0	5.9	5.4	5.4	14.8	23.8	37.1
TOTAL	**14.4**	**30.4**	**19.4**	**13.0**	**13.0**	**25.8**	**38.3**	**62.6**

Source: Public accounts of Canada and the Canadian Association of Petroleum Producers.

Table 7 compares trends in revenue with production to determine if the federal and Northwest Territories governments are capturing relatively more or less revenue today than in 1995. The figures in the table show that both revenue and production increased between 1995 and 2002. The increase in the amount of revenue, however, far exceeded the increase in production; between 1995 and 2002, revenue increased by 335 percent and production increased by a mere 14 percent. Correspondingly, revenue per unit of production increased by 281 percent, from $1.2/BOE to $4.5/BOE between 1995 and 2002.

Table 7 Revenue generation and production, Northwest Territories, 1995 to 2002

SUMMARY	1995	1996	1997	1998	1999	2000	2001	2002
Revenue (million 2000$)	14.4	30.4	19.4	13.0	13.0	25.8	38.3	62.6
Production (million BOE)	12	12	11	11	10	12	15	14
Revenue/Production (2000$/BOE)	**1.2**	**2.6**	**1.7**	**1.2**	**1.3**	**2.2**	**2.5**	**4.5**

Economic Rent in the Northwest Territories

Table 8 presents data for the value of oil and gas resources and the cost of oil and gas production annually for the Northwest Territories. Figures are shown as 2000$/BOE, like the revenue figures in the previous section. The value of oil and gas resources in the Northwest Territories almost doubled between 1995 and 2002. At the same time, the cost of production increased significantly. The high production cost figures in 1998, 2001 and 2002 are due to low production and additional oil and gas reserves in those years. In years of low economic rent, authorities were able to capture a high degree of it. In years of higher economic rent, authorities did a poor job of capturing economic rent.

Table 8 Resource value, production cost and economic rent (2000$/BOE), Northwest Territories, 1995 to 2002

	1995	1996	1997	1998	1999	2000	2001	2002
Resource Value	15.9	19.6	19.1	15.9	19.9	34.7	33.5	29.5
Production Cost	7.1	13.1	69.3	136.0	5.4	32.3	116.4	311.1
Economic Rent	8.8	6.5	0.0	0.0	14.4	2.4	0.0	0.0
Rent Capture	**13%**	**40%**	**100%**	**100%**	**9%**	**91%**	**100%**	**100%**

Source: Value figures from the Canadian Association of Petroleum Producers Statistical Handbook, Cost figures derived as per the methodology section of the report.

[11] Includes federal and territorial taxes.

Trends in Associated Environmental Impacts

As the United Nations Environment Programme pointed out in a news release earlier this year, "At the turn of this new millennium less than 15 percent of the Arctic's land was heavily impacted by human activity and infrastructure. However, if exploration for oil, gas, and minerals, developments such as hydro-electric schemes and timber extraction continue at current rates, more than half of the Arctic will be seriously threatened in less than 50 years."

Imperial Oil, the Aboriginal Pipeline Group, ConocoPhillips, Shell Canada and ExxonMobil have filed the Mackenzie Gas Project Preliminary Information Package, which outlines plans for developing natural gas from three onshore natural gas fields in the Mackenzie Delta and transporting it to market by pipeline. Combined, the three developments account for 164 billion m^3 (Gm^3) or 5.8 trillion cubic feet (Tcf). Expressions of interest from other potential gas suppliers, including the three so-called "anchor fields," suggest an initial gas volume of 34 million m^3 per day, or 1.2 billion cubic feet per day, may be shipped by the pipeline.

If approved and constructed, this Mackenzie Valley Pipeline would be the largest industrial development to occur in the North. The Preliminary Information Package also notes that the pipeline is expected to operate for at least 25 years. Initial development would occur from very large individual wellpads using directional drilling to drill six to 15 wells, depending on the depth of the reserve in the field. Over time, more wellpads (both large and small) would be added to exploit the full resource. The wellpads would need flare stacks, disposal wells, utility facilities, living quarters, service buildings, helicopter pads, connections to gathering pipelines and various field processing facilities (dehydration, line heaters, field compression).

If the pipeline is constructed, other production areas onshore and offshore may be developed. Each area would have its own wells and associated facilities and, as the initial wells are depleted, new wells would be needed to maintain or increase the supply of gas for the pipeline. Oil and gas development would likely occur where reserves can be found along the pipeline route, following a pattern similar to gas field development in northern Alberta and British Columbia, as described in the box below.

Typical Pattern of Oil and Gas Development

Starting with the most prolific reservoirs closest to the pipeline, companies begin to build permanent roads and wellpads and start to drill permanent production wells. Smaller diameter "gathering" pipelines are constructed to connect production wells to processing facilities. The processing facilities, in turn, are connected by pipeline to the large transmission pipeline. By the time pipeline construction has been completed, enough production wells, gathering system pipelines and processing facilities will also have been completed to generate enough gas to fill the pipeline for at least the first several years.

As the initial wells are depleted, new wells are drilled to maintain or increase the supply of gas for the pipeline. As a result, there is ongoing seismic exploration and drilling in producing areas, as well as in new areas on the edges of the producing area.

This pattern continues until the initial reserves of oil or gas, and any new oil or gas found after the decision to build the pipeline, are depleted or are no longer economically attractive to produce.

Land Disturbance

There are numerous environmental concerns associated with oil and gas activity, ranging from land disturbance and disruption of fish habitat to air pollution and damage caused by accidental spills. This section summarizes the land disturbance issues associated with oil and gas exploration and development.

Oil and gas exploration and production require extensive land clearing and infrastructure construction. Seismic cutlines, temporary and permanent roads, wellpads, camps, pipeline right of ways, processing facilities and airstrips or helicopter pads disturb the surface of the land and leave breaks or separations in ecosystems.

Over the life of an oil and gas producing area, the combination of repeated seismic surveys and land disturbances associated with drilling wells, operating well sites and constructing and operating pipelines can result in cumulative impacts. In areas where there are a lot of cutlines, right of ways and roads, wildlife and wildlife movement are affected. For example, although woodland caribou often cross cutlines to access adjoining habitat, they will generally avoid being within 250 metres of these lines.[12] Oil and gas infrastructure, combined with traffic and the continuous noise associated with drilling rigs, well sites and pipeline compressors, can also disturb wildlife. For example, Arctic caribou in oil and gas producing areas in Alaska are more vulnerable to predators, are exposed to more stress, which can affect reproductive productivity, and are forced to modify movement patterns.[13]

Seismic lines, roads and right of ways also provide extensive and long-term access to hunters, fishers, and industrial and recreational users, which can have a severe impact on wilderness areas and wildlife populations. While the impacts from a single well or road are relatively minor, the number of wells, roads and pipelines required to exploit a large oil or gas reserve lead to cumulative impacts.

Oil and gas development in Alaska started in 1960 with one producing oil field. By 2001, oil development comprised 19 producing fields, 20 pads with processing facilities, 115 pads with support facilities, 91 exploration sites, 13 offshore exploration islands, 4 offshore production islands, 16 airstrips, 1,395 culverts, 960 kilometres of roads and permanent trails, 725 kilometres of pipeline corridors, 353 kilometres of transmission lines, and gravel mines affecting 2,600 hectares.[14]

The Northwest Territories is already experiencing impacts associated with existing oil and gas developments. The focus of gas production in the territory is in the Fort Liard region. To investigate the extent of gas exploration and development impacts on the Fort Liard region, the Canadian Arctic Resources Committee with the Canadian Parks and Wilderness Association contracted Cizek Environmental Services.[15] The consultants estimated the cumulative effects of industrial development on the Fort Liard region of the Northwest Territories using the United

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[12] Dyer, Simon. *Movement and Distribution of Woodland Caribou in Response to Industrial Development in Northeastern Alberta.* Master of Science Thesis. Edmonton, Alberta: University of Alberta, 1999. Also available online at www.deer.rr.ualberta.ca/caribou/SD_MSc.pdf.

[13] Truett, J. and S. Johnson. *The Natural History of an Arctic Oil Field: Development and Biota,* 2000.

[14] National Research Council of the National Academies, *Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope*, March 2003.

[15] See www.carc.org/whatsnew/index.php3.

Nations Environment Programme's Globio Methodology for Mapping Human Impacts. The study considered the spatial impact (in terms of area of land disturbed and associated ecosystem impacts) of access roads, pipelines, wells, buildings, seismic lines, highways, communities and logging. Table 9 shows the results of the study for 2001.

Table 9 Estimated cumulative impacts in 2001

IMPACT TYPE	AREA IMPACTED	PERCENTAGE OF STUDY AREA
High risk of reduced survival/abundance of birds	234 km^2	1.7%
High risk of reduced survival/abundance of large mammals	5,609 km^2	39.6%
High risk of effects on plants, animals and food chains	2,022 km^2	14.3%

Source: Fort Liard Area Cumulative Impacts Mapping Project Technical Report

In addition to the analysis above, the consultants forecasted the impact of future developments in the area, assuming that the current rate of development continues. They concluded that by 2010 the impact area would cover roughly half of the study area, and by 2050 the impact area would cover virtually all of the study area.[16]

The experience of the Fort Liard region demonstrates the potential impacts of rapid development on a particular area. Although the Liard Valley is not necessarily representative of future developments in the Northwest Territories,[17] the impacts realized in this area are indicative of what could occur in other regions should development patterns mirror those of the Fort Liard area.

Summary

The trend in revenue generation in the Northwest Territories mirrors the trend in commodity prices. Figure 1 shows this clearly.

[16] One of the key outcomes of this analysis was recognizing the need for better mapping and impact documentation for oil and gas activities in terms of land disturbances.

[17] There are topographical, climatic, soil and ecotype differences between regions, so it is not appropriate to say that impacts will be uniform. In addition, some of the developments that have taken place in the Fort Liard region occurred when environmental practices were less stringent.

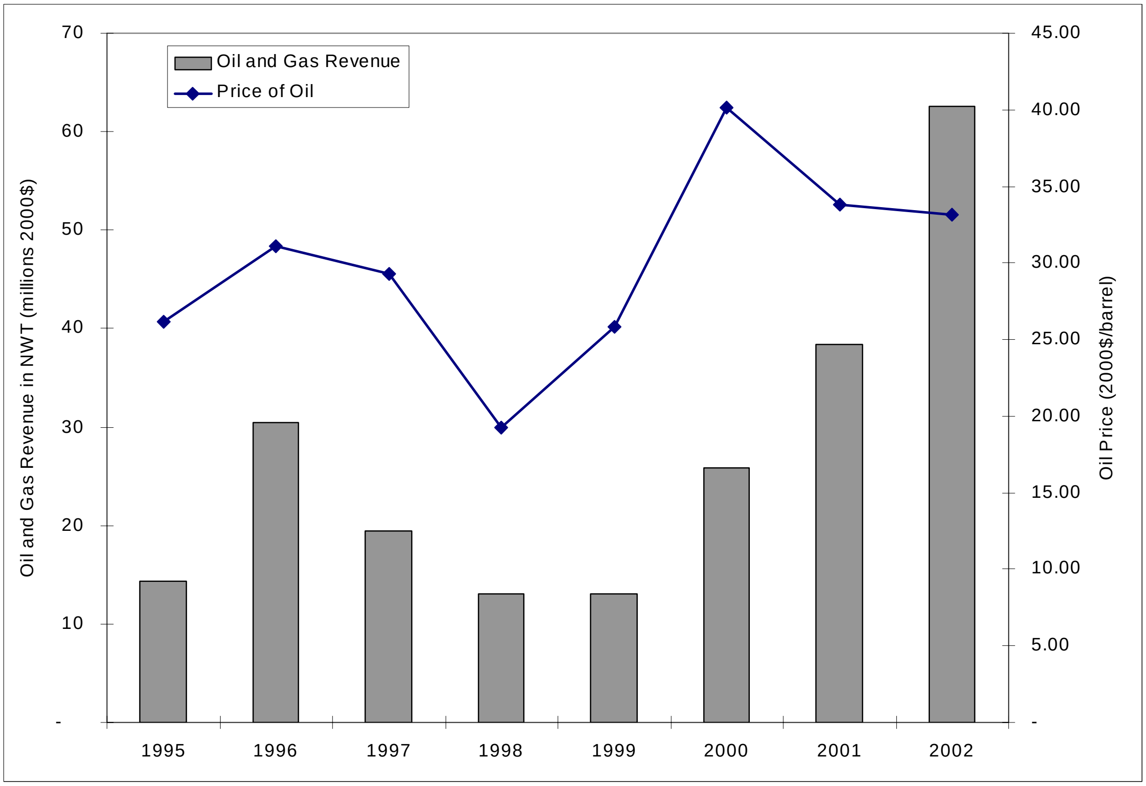

Figure 1 Trends in revenue generation in the Northwest Territories and the price of oil (2000$), 1995 to 2002

The Northwest Territories has the lowest level of revenue generation of any region considered in this analysis. While the Northwest Territories has a relatively high resource value, it also boasts high production costs which resulted in little rent available in select years over the study period. In years where substantial rent was available, authorities in the Northwest Territories have done a poor job of capturing it. The territory, like Yukon Territory, with its relatively small population and economy, is more vulnerable than Alberta, British Columbia and Saskatchewan. Smaller populations make for less diverse and resilient economies that are more sensitive to boom and bust economic cycles. As in Yukon Territory, in the Northwest Territories communities need protection from large developments that can cause significant, temporary and unsustainable spikes in economic performance. A key component in providing this stability is to develop appropriate resource management regimes.

Lower royalty rates in the Northwest Territories are often justified by the federal government on the basis of higher exploration and development costs relative to neighbouring Alberta or British Columbia. However, an analysis of wells in the Deh Cho First Nation territory revealed that all producing wells are less than 60 kilometres north of the Northwest Territories border.[18] South of the border, in Alberta and British Columbia, a significant amount of oil and gas activity is taking place, yet oil and gas producers in these jurisdictions pay significantly higher royalty rates.

[18] Petr Cizek. Value of Deh Cho Oil and Gas Production and Royalties. Prepared for Deh Cho First Nations, August 18, 2003.

Some of the costliest and deepest wells in North America are in British Columbia's foothills, not in the Deh Cho.[19]

The process for obtaining revenues from oil and gas developments in the Northwest Territories is complicated by the current process of authority transfer from the federal government to the territorial government. Elaborate agreements specify that as revenues from certain taxes collected by the territorial government increase, federal transfer and grant payments are reduced. Thus, increasing royalty rates in the Northwest Territories will not necessarily result in more revenue for the territory as a whole. This situation will change once the transfer of authority is complete. In the meantime, however, raising royalty rates is not the only means to obtain revenues in the region. The Northwest Territories government has several other options, including introducing a system of taxes and fees that would not be subject to federal clawback. The Northwest Territories government has not seriously considered implementing a surtax on high-profit resource corporations, a hydrocarbon production tax, a carbon tax or a capital investment tax.[20] All of these mechanisms could help the territorial government capture more revenue from oil and gas production.

Until 1994, relatively little exploration activity was taking place in the Northwest Territories. There was a moratorium on drilling in the Mackenzie Valley area because of unsettled Aboriginal land claims. The Department of Indian Affairs and Northern Development did not issue any exploration rights between 1977 and 1994. As First Nations complete land claim negotiations, oil and gas production will likely increase. Rights are now being issued annually in all parts of the territory where no opposition exists from Aboriginal people.[21] As land claims are settled, First Nations gain subsurface rights and the authority to collect royalties from oil and gas developments, which they have been doing with significant success.[22]

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[19] Cizek, Petr. *Value of Deh Cho Oil and Gas Production and Royalties*. Prepared by Cizek Environmental Services for Deh Cho First Nation, 2003.

[20] Cizek, Petr. *Bankrupting the North with Resource Extraction: A Royalty Rip-off*. Yellowknife, NWT, 2003.

[21] See www.gov.nt.ca/RWED/mog/oil_gas/issues.htm.

[22] For example, the Inuvialuit Regional Corporation used a cash bid system to distribute oil and gas rights and received $75 million for four parcels of land.

Regional Details: Yukon Territory

Yukon Territory is thought to possess significant oil and gas potential, although at the present time there are only two producing gas wells in the southeast portion of the territory. The Yukon government assumed responsibility for oil and gas developments in 1998 and has a regulatory framework and royalty/tax regime to support and facilitate oil and gas production. In this section, we describe the methods the Yukon government uses to obtain revenues from oil and gas production in the territory. We also present quantitative estimates of revenue generation, cost of production and the value of the resources over the study period, and discuss the environmental impacts associated with oil and gas production in the territory. We begin by presenting background information on oil and gas production in Yukon Territory.

Background

In this section, we identify the government authorities that play a role in regulating, managing and/or facilitating oil and gas production in Yukon Territory. For each authority, we provide a brief description of its relevant responsibilities. We also present background information on the oil and gas sector, with figures for oil and gas production, employment in the oil and gas sector, and gross domestic product associated with oil and gas production in Yukon Territory.

Responsible Authorities

Yukon Territory gained responsibilities and powers over its land and resources through a process of negotiated devolution. In November 1998, the territorial government assumed responsibility for oil and gas developments. Since that time, the Yukon government has been granting dispositions (or authorizations) in the form of permits and leases, collecting royalties, regulating the industry, monitoring oil and gas activities, and enforcing regulations. The *Yukon Oil and Gas Act* was passed by the Yukon Legislative Assembly and received royal assent in November 1998. Oil and gas regulations are currently being developed pursuant to the *Yukon Oil and Gas Act* and are at various stages of completion. A royalty regulation was drafted in October 1999 and remains in draft form. Other regulations (the Oil and Gas Transfer Regulations and the Oil and Gas Disposition Regulations) have already been finalized and adopted.

Within the Yukon government, the Department of Energy, Mines and Resources is the main authority for regulating, managing and facilitating oil and gas developments in the territory, with two of its branches[1]:

1. The **Department of Energy, Mines and Resources** is responsible for managing natural resources within the territory, with the exception of Settlement A lands (see discussion below).
2. The **Oil and Gas Management Branch** of the **Department of Energy, Mines and Resources** is mandated to regulate, manage and encourage the development of Yukon Territory's resource potential and emerging oil and gas industry, including issuing oil and gas rights and administering royalty regulations.

[1] Oil and Gas Management Branch/Oil and Gas Business Development Branch. *Yukon Oil and Gas*. Whitehorse, Yukon: Yukon Department of Energy, Mines and Resources, 2003.

3. The **Oil and Gas Business Development Branch** of the **Department of Energy, Mines and Resources** is mandated to encourage the development of Yukon Territory's resource potential and emerging oil and gas industry.[2]

While the Yukon government has the authority to grant dispositions to oil and gas companies, First Nations living in Yukon Territory also play a role in oil and gas developments. In recent years, through what is called the Umbrella Final Agreement (UFA), 14 Yukon First Nation's land claim agreements have been or are being resolved. So far, eight comprehensive land claims have been signed and four other First Nations have signed Memoranda of Understanding signifying that substantive negotiations have been concluded and the parties are committed to the next steps.[3] Detailed legal drafting is underway to prepare a final land claims package for a ratification vote by each of those four First Nations.[4] The conditions under which oil and gas developments on First Nation's land take place depend on the level of control a particular First Nation has over surface and subsurface rights. The First Nations own both surface and subsurface rights on lands categorized as "Settlement A." First Nation governments need their own disposition schemes and are able to pass their own oil and gas laws to regulate industry on these lands.[5] Companies must consult First Nation governments and get their approval for any oil and gas development on Settlement A lands. Without First Nation approval, a project cannot proceed.

On land classified as "Settlement B," First Nations own only surface rights. The Yukon government owns the subsurface rights on these lands. Companies must consult and get approval from First Nation governments only if the First Nation has an “equivalent law” that states that the First Nation will consult with the government when it issues a Call for Bids on Settlement A lands. If the First Nation does not have an equivalent law, the First Nation government may still be consulted, in good faith, about proposed developments on Settlement B lands, but there is no requirement to do so and the territorial government makes the final decision, under the *Yukon Oil and Gas Act*.

If a First Nation has not settled an individual final agreement and does not own Settlement A or Settlement B lands, the First Nation can refuse any project in its “traditional territory.” Traditional territories are defined in the Umbrella Final Agreement. However, if the federal government granted dispositions before the Umbrella Final Agreement was finalized, according to the *Yukon Oil and Gas Act*, “All oil and gas rights previously granted by the federal government remain in effect until they expire, are given back to the holder, or the holder and the Yukon government mutually agree.”

Gas Production in Yukon Territory

Until recently, oil and gas development in Yukon Territory was limited. Exploration and some production occurred during the 1960s. Companies discovered and produced natural gas in southeast Yukon and on the Liard Plateau, and recovered oil in Eagle Plains. Seventy wells were drilled in Yukon Territory prior to 1985, with a more recent well drilled in 1991. Market

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[2] Oil and Gas Management Branch/Oil and Gas Business Development Branch. *Yukon Oil and Gas*. Whitehorse, Yukon: Yukon Department of Energy, Mines and Resources, 2003.
[3] Op. cit.
[4] Op. cit.
[5] When First Nations do not have their own laws to regulate oil and gas activity on 'Settlement A' lands, the regulatory sections of the *Yukon Oil and Gas Act* apply to First Nations 'Settlement A' lands.

conditions, lack of pipeline access to southern markets, and unresolved land claim issues have discouraged industry interest in Yukon Territory in the past.[6]

Now developers are becoming more interested in developing oil and gas potential in the territory. They are attracted by rising prices, growth in the continental demand for natural gas, the potential development of a gas transmission pipeline from Alaska or the Mackenzie Valley in the Northwest Territories to southern Canada and the United States, and the settlement of most land claim agreements. Indeed, industry has committed to spend $725 million in northern Canada and drill 22 wells.[7] In the 40 years leading up to the autumn of 2002, companies discovered about 14.4 billion cubic metres of natural gas in Yukon Territory and about 1.5 million cubic metres of oil.[8] Currently, the only producing wells are the two Kooteneelee gas wells operating in the southeast. Table 1 shows gas production from 1995 to 2002, inclusive. The figures demonstrate that production of natural gas in the territory has decreased slightly over this time period, with relatively higher production years occurring in 1999 and 2000. This increase in production in 1999 and 2000 coincides with higher prices for natural gas over the same period. Total production decreased by 16 percent between 1995 and 2002.

Table 1 Gas production, Yukon Territory, 1995 to 2002 (million BOE)

PRODUCTION	1995	1996	1997	1998	1999	2000	2001	2002
Natural Gas	2.78	2.68	2.54	2.84	3.95	3.58	2.99	2.33

Source: Statistics Canada, Publication 26-213-XPb

The Yukon government is anticipating a dramatic increase in oil and gas investment once construction is announced for either the Mackenzie Valley Pipeline or the Alaska Highway Pipeline. Yukon Territory has eight areas with oil and gas potential. Six of the eight areas are in the northern part of the territory. To date, only two of these northern areas have been the focus of oil and gas exploration: Eagle Plains in the north-central Yukon, and Peel Plateau in the lower northeast. The two southern areas, Whitehorse and the Liard Plateau, are contiguous with basins in British Columbia. In the south, only the Liard Plateau has been subject to exploration activity. Petroleum resource assessments have been completed for all eight of the areas.[9] Yukon Territory's natural gas potential is estimated to be about 20 trillion cubic feet, while crude oil potential is estimated at 900 million barrels.[10] The vast majority of this potential is located in two basins: the North Coast Basin and the Kandik Basin. The Kandik Basin straddles the Canada-U.S. border.[11]

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[6] Wilson, Niki and Chris Severson-Baker. 2004. *Citizens Rights and Oil and Gas Development: Yukon Territory.* Alberta: Pembina Institute for Appropriate Development.

[7] Canadian Association of Petroleum Producers Web site. See www.capp.ca.

[8] Wilson, Niki and Chris Severson-Baker. 2004. *Citizens Rights and Oil and Gas Development: Yukon Territory.* Alberta: Pembina Institute for Appropriate Development.

[9] Oil and Gas Management Branch/Oil and Gas Business Development Branch. *Yukon Oil and Gas*. Whitehorse, Yukon: Yukon Department of Energy, Mines and Resources, 2003.

[10] Wilson, Niki and Chris Severson-Baker. 2004. *Citizens Rights and Oil and Gas Development: Yukon Territory.* Alberta: Pembina Institute for Appropriate Development.

[11] Oil and Gas Management Branch/Oil and Gas Business Development Branch. *Yukon Oil and Gas*. Whitehorse, Yukon: Yukon Department of Energy, Mines and Resources, 2003.

Gas Employment in Yukon Territory

Table 2 presents direct employment figures for gas production in Yukon Territory from 1995 to 2002, inclusive.[12] The table also presents total employment figures for the territory, as well as the share of total employment attributable to gas production. Both employment related to gas production and total employment in Yukon Territory increased between 1995 and 2002, by 33 percent and 65 percent, respectively. As the figures indicate, however, direct employment in the natural gas sector in Yukon Territory constitutes a small portion of total employment.

Table 2 Employment associated with gas production and total employment, Yukon Territory, 1995 to 2002

EMPLOY'T	1995	1996	1997	1998	1999	2000	2001	2002
Gas	11	11	12	2	1	9	7	16
Total	12,150	13,422	15,726	15,661	21,397	21,874	24,257	25,993
% of Total	0.09%	0.08%	0.08%	0.01%	0.00%	0.04%	0.03%	0.06%

Source: Statistics Canada, CANSIM Table 383-0009

To facilitate increased local employment from oil and gas developments in Yukon Territory, before any oil and gas activity that is expected to cost more than $1 million over a 12-month period can proceed, a “benefits agreement” must be in effect. A benefits agreement is negotiated between three parties: the licencee, the Yukon government and the affected First Nation(s). In the benefits agreement, the licencee (or company with a licence) provides First Nations, community residents, and other people in Yukon Territory with opportunities for employment training, and the opportunity to supply goods and services to the licencee and its contractors.[13]

Gas Gross Domestic Product in Yukon Territory

Table 3 presents gross domestic product (GDP) associated with gas production, total provincial GDP, and gas GDP as a percentage of GDP generated by all industries. The figures in the table demonstrate that the growth of all industries combined has outpaced the growth of the gas sector quite significantly. Between 1995 and 2002, GDP associated with gas production declined very slightly. Over the same period, “all industries” GDP increased by 9 percent. Gas GDP as a percentage of “all industries” GDP declined by 15 percent between 1995 and 2002. These figures indicate that gas production constitutes a relatively small portion of the total economy in Yukon Territory.

[12] Employment figures for the oil and gas sector for 1995 and 1996 were not available in the same format as the 1997 to 2002 figures because of a change in industry classifications between 1996 and 1997 from the Standard Industry Classification System to the North American Industry Classification System. Employment figures for 1995 and 1996 were therefore estimated based on a correlation between employment and production in other years.

[13] Oil and Gas Management Branch/Oil and Gas Business Development Branch. *Yukon Oil and Gas*. Whitehorse, Yukon: Yukon Department of Energy, Mines and Resources, 2003.

Table 3 GDP associated with gas production and territorial GDP, Yukon Territory, 1995 to 2002 (million 2000$)

GDP	1995	1996	1997	1998	1999	2000	2001	2002
Gas	12	13	11	6	17	20	17	11
All Industries	1,135	1,203	1,154	1,143	1,111	1,188	1,206	1,207
% of Total	1.1%	1.1%	0.9%	0.5%	1.5%	1.7%	1.4%	0.9%

Source: Statistics Canada, CANSIM Table 379-0025

Oil and Gas Revenue Generation

Yukon Territory has adopted a system of permits and leases that convey oil and gas rights. A permit allows exploration, while a lease[14] is required for production. Oil and gas rights are issued following a process that ends with a call for bids on a specific parcel of land. Rights are currently issued based on a work bid scheme (which does not recover economic rent). Rental fees are set contractually through the permit and announced with the call for bids. To date, the Yukon call for bids has stated that rentals are zero for the initial term of permits. In the second term of permits, rentals are $5.00/hectare. The maximum term for a permit is 10 years; six years for the initial term, with the possibility of a four-year extension.[15]

The disposition process confers specific oil and gas rights for certain locations, but does not grant the right to undertake activity. Before any oil and gas exploration or development can occur, companies must obtain a licence. Once rights are granted and licences are issued, production begins and the Yukon government collects royalties from oil and gas producers as production takes place. The royalty regulation is still in draft form for Yukon Territory, but, as proposed, royalty rates vary with age and price, and range from a minimum of 5 percent for the initial production period to a maximum of 10 to 15 percent in the following years.[16]

In addition to territorial royalties, leases, licences and rentals, oil and gas producers in Yukon Territory must pay federal and territorial income taxes. Table 4 summarizes the fees paid by oil and gas producers in Yukon Territory.

[14] Note that Yukon Territory has not granted any leases post-devolution. All production is occurring on grandfathered federal leases acquired pre-devolution.
[15] Oil and Gas Management Branch/Oil and Gas Business Development Branch. *Yukon Oil and Gas*. Whitehorse, Yukon: Yukon Department of Energy, Mines and Resources, 2003.
[16] Op. cit.

Table 4 Key means of revenue generation, Yukon Territory

COMPONENT	KEY ATTRIBUTES
Royalties	Yukon Territory's royalty regulations are currently in draft form. The proposed rates range from a minimum of 5% to a maximum of 15%. The minimum of 5% applies to the first three years of production, after which rates range from 10% to 15%, in accordance with a formula that is sensitive to oil and gas prices.
Dispositions	Under the *Yukon Oil and Gas Act,* rights to oil and gas are granted by the Minister in the form of work dispositions. Dispositions are issued following a five-step process that ends with a call for bids. A disposition grants oil and gas rights for a six- to 10-year term.
Rentals	During the initial six-year term of a permit issued under the current Yukon disposition process, no rental payments are due. In the second, four-year term, rentals are $5 per hectare.
Leases	Grandfathered federal production leases exist in Yukon Territory despite devolution. To date, no leases have been issued by the Yukon government. Rentals and grandfathered production leases are $1 per hectare.
Licences	This category includes grandfathered federal Significant Discovery Licences (SDL) and Exploration Licences (EL). There are currently no rentals or any grandfathered EL or SDL.
Corporate Income Tax	The Yukon Territory corporate income tax rate is 15%.
Federal Income Tax	The net federal corporate income tax rate for oil and gas companies is 28%, against which the government allows a number of deductions.

Oil and gas producers in Yukon Territory benefit from one of the lowest corporate tax rates in Canada,[17] as well as an exemption from the territorial fuel tax and a number of federal initiatives described in Table 5.

[17] Oil and Gas Management Branch/Oil and Gas Business Development Branch. *Yukon Oil and Gas*. Whitehorse, Yukon: Yukon Department of Energy, Mines and Resources, 2003.

Table 5 Key deductions and credits related to oil and gas, Yukon Territory

COMPONENT	KEY ATTRIBUTES
Fuel Tax Exemption	An exemption for fuel used in off-road commercial activities, including oil and gas production.
Federal Capital Cost Allowance	A deduction against income for depreciating property; Class 41 covers oil and gas equipment and allows a 25% writedown of equipment on a declining balance basis.
Federal Resource Allowance	A notional allowance in lieu of deduction of territorial royalties and freehold mineral taxes; over the study period, the deduction was 25% of taxable net resource profits.
Federal Exploration and Development Expenses	Exploratory and development expenses are grouped into one of three pools: Canadian Exploration Expenses (CEE), Canadian Development Expenses (CDE), and Canadian Oil and Gas Property Expenses (COGPE). The CEE balance of exploration expenditures is fully deductible against income, with any unclaimed portion carried forward indefinitely. Up to 30% of the CDE balance and up to 100% of the COGPE balance can be applied against income.
Federal Earned Depletion	An additional deduction from taxable income of certain exploration and development expenditures and other resource investments; the deductions for earned depletion are generally limited to 25% of the taxpayer's annual resource profits. [18]

Quantitative Results of Revenue Generation

Table 6 demonstrates the trend in revenue generation obtained from oil and gas producers in Yukon Territory from 1995 to 2002. The major sources of revenue were royalties and income taxes. Revenue increased substantially between 1995 and 2002, from $3.4 million to $10.6 million.

[18] While Earned Depletion is currently being phased out, federal government expenditures related to it continued until 2001.

Table 6 Revenue from oil and gas production, Yukon Territory, 1995 to 2002 (million 2000$)

REVENUE SOURCE	1995	1996	1997	1998	1999	2000	2001	2002
Gas Royalties	1.7	3.7	3.1	3.1	2.1	3.3	10.0	4.2
Income Taxes	1.68	3.59	1.37	1.43	2.20	4.50	4.64	6.33
TOTAL	**3.4**	**7.3**	**4.5**	**4.6**	**4.3**	**7.8**	**14.6**	**10.6**

Source: Yukon Public Accounts, Public Accounts of Canada and the Canadian Association of Petroleum Producers

Table 7 compares trends in revenue generation with production to determine if the Yukon government is capturing relatively more or less revenue today than in the past. The figures in the table show that revenue increased between 1995 and 2002 and production decreased between 1995 and 2002. It is clear from the numbers presented below that the rate at which revenue generation increased is much more significant than the rate at which production decreased.

Table 7 Revenue generation and oil and gas production, Yukon Territory, 1995 to 2002

SUMMARY	1995	1996	1997	1998	1999	2000	2001	2002
Revenue (million 2000$)	3.4	7.3	4.5	4.6	4.3	7.8	14.6	10.6
Production (million BOE)	2.8	2.7	2.5	2.8	4.0	3.6	3.0	2.3
Revenue/Production (2000$/BOE)	**1.2**	**2.7**	**1.8**	**1.6**	**1.1**	**2.2**	**4.9**	**4.5**

Economic Rent in Yukon Territory

Table 8 presents data for the value of oil and gas resources and the cost of oil and gas production annually for Yukon Territory. Figures are shown as 2000$/BOE, like the revenue figures in the previous section. The value of oil and gas resources in Yukon Territory almost doubled between 1995 and 2002. At the same time, the cost of production increased. In several years the cost of production exceeded the value of the resource resulting in zero economic rent. In other years the Yukon government did a poor job of capturing economic rent from gas developments in the territory.

Table 8 Resource value, production costs and economic rent (2000$/BOE), Yukon Territory, 1995 to 2002

	1995	1996	1997	1998	1999	2000	2001	2002
Resource Value	16.5	20.4	19.4	16.0	20.0	34.7	33.4	30.0
Production Cost	7.4	13.6	70.3	136.6	5.5	32.3	115.9	316.8
Economic Rent	9.1	6.8	0.0	0.0	14.5	2.4	0.0	0.0
Rent Capture	**13%**	**40%**	**100%**	**100%**	**8%**	**91%**	**100%**	**100%**

Source: Value figures from the Canadian Association of Petroleum Producers Statistical Handbook, Cost figures derived as per the methodology section of the report.

Trends in Associated Environmental Impacts

Compared to the other regions we analyzed, oil and gas production in Yukon Territory occurs on a small scale. As a result, the environmental impacts associated with past exploration and current production of oil and gas have been relatively minor. However, evidence of seismic and exploration drilling activity conducted between the early 1970s and the mid-1980s in the northern part of the territory is still visible today, due to the sensitivity of Arctic soil to disturbance and slow-growing Arctic vegetation. If full-scale oil and gas development were to occur in an area of relatively pristine wilderness, characteristic of much of Yukon Territory, it would have a significant impact. Wildlife habitat and migration routes could be affected and, depending on the region, First Nations' traditional activities may also be adversely affected.

Construction of a large-capacity gas transmission pipeline to transmit gas from either Alaska (down the Alaska Highway) or from the Mackenzie Delta (down the Mackenzie Valley) to supply southern markets would encourage oil and gas companies to seek approval to expand seismic and exploration drilling activities in Yukon Territory. If those companies had successful exploration drilling programs, they would seek approval to conduct more seismic exploration followed once again by more exploration drilling. This pattern would be repeated until enough gas was found to justify the cost of building a lateral pipeline to connect Yukon gas development to the larger transmission pipeline. Once companies became confident that a lateral pipeline was going to be constructed, development would start to follow a pattern similar to gas field development in northern Alberta and British Columbia, described in the box below.

Typical Pattern of Oil and Gas Development

Starting with the most prolific reservoirs closest to the pipeline, companies begin to build permanent roads and wellpads and start to drill permanent production wells. Smaller diameter "gathering" pipelines are constructed to connect production wells to processing facilities. The processing facilities, in turn, are connected by pipeline to the large transmission pipeline. By the time pipeline construction has been completed, enough production wells, gathering system pipelines and processing facilities will also have been completed to generate enough gas to fill the pipeline for at least the first several years.

As the initial wells are depleted, new wells are drilled to maintain or increase the supply of gas for the pipeline. As a result, there is ongoing seismic exploration and drilling in producing areas, as well as in new areas on the edges of the producing area.

This pattern continues until the initial reserves of oil or gas, and any new oil or gas found after the decision to build the pipeline, are depleted or are no longer economically attractive to produce.

Land Disturbance

There are numerous environmental concerns associated with oil and gas activity, ranging from land disturbance and disruption of fish habitat to air pollution and damage caused by accidental spills. This section summarizes the land disturbance issues associated with oil and gas exploration and development.

Oil and gas exploration and production require extensive land clearing and infrastructure construction. Seismic cutlines, temporary and permanent roads, wellpads, camps, pipeline right of ways, processing facilities and airstrips or helicopter pads disturb the surface of the land and leave breaks or separations in ecosystems. Over the life of an oil and gas producing area, the combination of repeated seismic surveys and land disturbances associated with drilling wells, operating well sites and constructing and operating pipelines can result in cumulative impacts. In areas where there are a lot of cutlines, right of ways and roads, wildlife and wildlife movement are affected. For example, although woodland caribou often cross cutlines to access adjoining habitat, they will generally avoid being within 250 metres of these lines.[19] Oil and gas infrastructure, combined with traffic and the continuous noise associated with drilling rigs, well sites and pipeline compressors, can also disturb wildlife. For example, Arctic caribou in oil and gas producing areas in Alaska are more vulnerable to predators, are exposed to more stress, which can affect reproductive productivity, and are forced to modify movement patterns.[20]

Seismic lines, roads and right of ways also provide extensive and long-term access to hunters, fishers, and industrial and recreational users, which can have a severe impact on wilderness areas and wildlife populations. While the impacts from a single well or road are relatively minor, the number of wells, roads and pipelines required to exploit a large oil or gas reserve lead to cumulative impacts.

Oil and gas development in Alaska started in 1960 with one producing oil field. By 2001, oil development comprised 19 producing fields, 20 pads with processing facilities, 115 pads with support facilities, 91 exploration sites, 13 offshore exploration islands, 4 offshore production islands, 16 airstrips, 1,395 culverts, 960 kilometres of roads and permanent trails, 725 kilometres of pipeline corridors, 353 kilometres of transmission lines, and gravel mines affecting 2,600 hectares.[21]

Summary

As in all other regions, the trend in revenue generation in Yukon Territory mirrors the trend in the price of natural gas. Figure 1 shows this clearly.

[19] Dyer, Simon. *Movement and Distribution of Woodland Caribou in Response to Industrial Development in Northeastern Alberta.* Master of Science Thesis. Edmonton, Alberta: University of Alberta, 1999. Also available online at www.deer.rr.ualberta.ca/caribou/SD_MSc.pdf.
[20] Truett, J. and S. Johnson. *The Natural History of an Arctic Oil Field: Development and Biota*, 2000.
[21] National Research Council of the National Academies. *Cumulative Environmental Effects of Oil and Gas Activities on Alaska's North Slope*, March 2003.

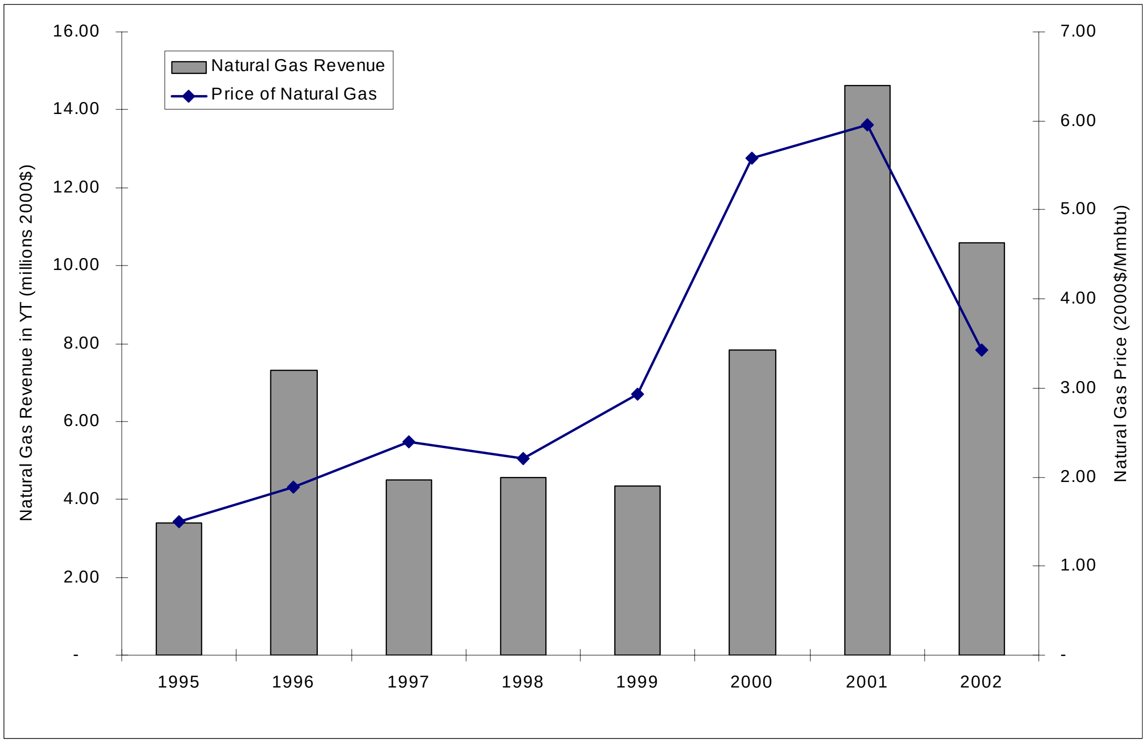

Figure 1 Trends in revenue generation in Yukon Territory and the price of natural gas (2000$), 1995 to 2002

It is worth highlighting that revenue generation in Yukon Territory was lower than in any of the Canadian provinces included in this analysis. At the same time, in years where economic rent was available, the government in Yukon Territory captured a very small portion of it. Yukon Territory, with its relatively small population and economy, is more vulnerable than other regions. Smaller populations make for less diverse and resilient economies that are more sensitive to boom and bust economic cycles. The Yukon government needs to provide stability to affected communities so large developments do not cause significant, temporary and unsustainable spikes in economic performance. A key component in providing this stability is to develop appropriate resource management policies to ensure that the citizens of the region are appropriately compensated for the development of non-renewable resources.

Lower royalty payments in regions with high investment and operating costs are often justified as a way to provide incentive to oil and gas companies to undertake developments. However, in many regions, including Yukon Territory, development is motivated largely by factors beyond royalty rates and associated royalty regimes. For example, if Alaskan developers decide to build a pipeline down the Alaska Highway, production of some Yukon gas would become more viable. As well, construction of the Mackenzie Pipeline opens up the possibility of construction of the so-called Dempster Lateral Pipeline into Yukon Territory, if seismic and exploration drilling in the northern part of the territory resulted in the discovery of large proven reserves. Finally, the price of gas could continue to increase because of insatiable demand from the United States and eastern Canada, making Yukon gas more economically attractive to produce. Local governments have little or no control over these factors and the influence they will have on oil and gas developments. It is crucial, therefore, that resource management policies for any region do not focus solely on attracting oil and gas investment. Rather than designing a regime that provides the best deal to developers, governments need to plan for future generations, protect against boom and bust economic cycles, maintain revenue streams into the future, and plan for a transition away from non-renewable resources towards renewable resources over time.

Regional Details: Norway

In this appendix, we describe the methods the government uses to obtain revenues from oil and gas production in Norway. We present quantitative estimates of revenues as well as cost and resource value figures over the study period and discuss environmental impacts associated with oil and gas production in the country. We begin with background information on oil and gas production in Norway.

Background

Below we identify the government authorities that play a role in regulating, managing and/or facilitating oil and gas production in Norway. For each authority, we provide a brief description of its relevant responsibilities. We also present background information on the oil and gas sector, with figures for oil and gas production, employment in the oil and gas sector, and gross domestic product associated with oil and gas production in Norway.

Responsible Authorities

Several government authorities in Norway have responsibilities related to oil and gas production in the country. Those most relevant to oil and gas developments are the following:

1. The **Ministry of Petroleum and Energy** has primary responsibility for implementing energy policy. It is supported by the Norwegian Petroleum Directorate and the Norwegian Energy and Water Administration.
2. The **Norwegian Petroleum Directorate** is responsible for the administrative and supervisory control of oil and gas activities.
3. The **Norwegian Energy and Water Administration** is responsible for regulation and monitoring of the electricity industry.
4. The **Ministry of Local Government and Labour** has overall responsibility for the working environmental, emergency preparedness and safety aspects of the petroleum industry.
5. The **Research Council of Norway** is responsible for public funding of energy research and development.

Oil and Gas Production in Norway

Norway has been producing oil and gas since the early 1970s and is now the largest offshore oil producer in the world and the third-largest offshore gas producer (behind the United States and the United Kingdom).[1] There are currently 40 oilfields and 40 gas fields in production in Norway, divided into three main areas: the North Sea, the Norwegian Sea and the Barents Sea. The current focus of activity is the North Sea, which has the largest reserves and results in the majority of production. The largest undeveloped resources are in the Norwegian Sea and Barents Sea. Table 1 shows oil and gas production from 1995 to 2002, inclusive. As the figures indicate, Norway has experienced a fairly significant increase in oil and gas production since 1995. Indeed, over the study period, natural gas production increased by 135 percent, while oil production increased by 15 percent.

[1] Norway's oil and gas reserves are all offshore.

Table 1 Oil and gas production, Norway, 1995 to 2002 (million BOE)

PRODUCTION	1995	1996	1997	1998	1999	2000	2001	2002
Oil	1,059	1,184	1,198	1,147	1,145	1,225	1,247	1,216
Natural gas	175	235	270	278	304	313	335	412
Total	**1,234**	**1,420**	**1,468**	**1,425**	**1,449**	**1,538**	**1,581**	**1,628**

Source: 2003 Norwegian Petroleum Activity Fact Sheet

At current extraction rates and with current technology, oil reserves in Norway could be exhausted in the next 20 years, while gas reserves are likely to last much longer (more than 80 years).[2] Indeed, the Norwegian Ministry of Petroleum and Energy has estimated that recoverable reserves are more than four times the level already recovered.

Oil and Gas Employment in Norway

Table 2 presents direct employment figures for oil and gas production in Norway. The table also presents total employment figures for the country, as well as the share of total employment attributable to oil and gas production. The figures indicate that, while total employment in the country has increased (by 10 percent between 1995 and 2002), employment associated with oil and gas production has declined by 7%. As a result, the portion of total employment attributable to oil and gas has also declined (by 16 percent between 1995 and 2002).

Table 2 Employment associated with oil and gas production and total employment, Norway, 1995 to 2002, thousands

EMPLOY'T	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas	18	17	16	16	16	17	16	16
Total	2,113	2,156	2,220	2,276	2,294	2,304	2,316	2,321
% of Total	1%	1%	1%	1%	1%	1%	1%	1%

Source: 2003 Norwegian Petroleum Activity Fact Sheet

Oil and Gas Gross Domestic Product in Norway

Table 3 presents gross domestic product (GDP) associated with oil and gas production, total state GDP, and oil and gas GDP as a percentage of GDP generated by all industries. The figures in the table demonstrate that the growth of the oil and gas sector has outpaced the growth of the total economy. While GDP associated with oil and gas production increased by 78 percent between 1995 and 2002, total GDP increased 39 percent over the same period. Oil and gas GDP as a percentage of total GDP also increased between 1995 and 2002. It is worth noting that the oil and gas sector comprises a fairly significant portion of the total economy, accounting for 17 percent of total GDP in 2002.

[2] Norway Ministry of Finance.

Table 3 GDP associated with oil and gas production and national GDP, Norway, 1995 to 2002 (million 2000$)

GDP	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas	28,245	40,034	42,446	26,935	39,042	61,590	54,072	50,163
All Industries	212,080	229,641	242,167	241,269	256,865	296,753	299,295	294,353
% of Total	13%	17%	18%	11%	15%	21%	18%	17%

Source: 2003 Norwegian Petroleum Activity Fact Sheet and www.ssb.no/english/subjects/09/01

Oil and Gas Revenue Generation

In Norway, production licences give companies the right to explore, drill, produce and sell oil and gas in the country for a certain period of time. Production licences are awarded to individual companies or groups of companies. Unlike in Canada and the United States, in Norway licences are not auctioned off. Instead, they are awarded to oil and gas companies and revenue is obtained mainly through a system of taxes and direct ownership of resources. The rationale behind Norway's use of taxes and ownership is that it disperses exploration risks over a large number of wells and companies, rather than just those companies willing to place significant bids in an auction.[3] Once licences are conveyed and production begins, the Norwegian government collects revenues from oil and gas producers through royalties, area fees and a carbon dioxide tax, among other taxes (see Table 4).

[3] Norway Ministry of Finance. *Ministry of Finance Long-term Programme, 1998-2001*.

Table 4 Key means of revenue generation, Norway

COMPONENT	KEY ATTRIBUTES
State Directed Financial Interest (SDFI)	The SDFI was established in 1985, and an SDFI interest is incorporated into most licences awarded after that year. Under the SDFI arrangement, the state pays a share of all investment and operating costs in a project, corresponding to its direct interest. It also receives a corresponding proportion of production and other revenues on the same terms as other licences. In the spring of 2001, Petoro AS was established as a state-owned company to manage SDFI.
Statoil Dividends	In the hydrocarbon sector, the government has the largest presence on the Norwegian continental shelf through ownership of Statoil, majority shares in Norsk Hydro and its explicit participation through the State Directed Financial Interest.
CO_2 Tax	A carbon dioxide tax is levied at a rate per standard cubic metre (scm) of gas burned. The rate for 2003 is NOK 0.75 per litre of oil/scm of gas.
Royalties	Royalties are being phased out and are paid today by two fields, Gullfaks and Oseberg.
Income and Special Taxes	The corporate income tax rate in Norway is 28%. A special tax of 50% is also levied on the petroleum industry. When calculating taxable income, investment is subject to depreciation on a straight-line basis over six years from the date it is made. Companies can also deduct costs associated with land and offshore operations.
Production Licence	The production licence regulates the rights and duties of licencees in relation to the state. A production licence grants an exclusive right to explore for and produce petroleum within its specified geographic area.

Several deductions and credits are available to oil and gas producers in Norway. These are briefly described in Table 5.

Table 5 Key deductions and credits related to oil and gas, Norway

COMPONENT	KEY ATTRIBUTES
Accelerated Investment Depreciation	Investment is subject to depreciation on a straight-line basis over six years from the date the investment took place.
Expenditure Deduction	Expenditure related to oil and gas operations can be deducted based on the value of the assets. An uplift of 5% of investment is deductible from the income base to determine the special tax over a six-year period from the date of investment.
Exploration Costs	Exploration costs are fully deductible in the year they are incurred.

Quantitative Results of Revenue Generation

Table 6 demonstrates the trend in revenue generation from oil and gas producers in Norway. The major sources of revenue are funds from the State Directed Financial Interest, the corporate income tax and the special tax. Total revenues increased by a significant 200 percent between 1995 and 2002 in Norway.

Table 6 Revenue from oil and gas production, Norway, 1995 to 2002 (million 2000$)

REVENUE SOURCE	1995	1996	1997	1998	1999	2000	2001	2002
SDFI	2,392	9,250	10,177	3,213	5,661	18,463	21,393	12,912
Statoil	375	442	371	602	28	307	941	860
CO_2 Tax	650	717	742	696	708	559	481	512
Royalties	1,533	1,673	1,576	819	687	649	415	239
Corporate Tax	2,044	2,605	3,895	1,985	1,228	4,129	7,070	5,697
Special Tax	2,811	3,418	4,915	2,415	1,353	6,184	10,970	9,176
TOTAL	**9,805**	**18,105**	**21,675**	**9,730**	**9,664**	**30,291**	**41,270**	**29,396**

Table 7 compares trends in revenue generation with production to determine if the Norwegian government is capturing relatively more or less revenue today than in 1995. The figures in the table show that both revenue and production increased between 1995 and 2002. More specifically, between 1995 and 2002, revenue increased by 200 percent and oil and gas production increased by 32 percent. Over the same time, revenue per unit of production increased by 127 percent, from $7.9/BOE to $18.1/BOE between 1995 and 2002.

Table 7 Revenue generation and oil and gas production, Norway, 1995 to 2002

SUMMARY	1995	1996	1997	1998	1999	2000	2001	2002
Revenue (million 2000$)	9,805	18,105	21,675	9,730	9,664	30,291	41,270	29,396
Production (million BOE)	1,234	1,420	1,468	1,425	1,449	1,538	1,581	1,628
Revenue/Production (2000$/BOE)	**7.9**	**12.8**	**14.8**	**6.8**	**6.7**	**19.7**	**26.1**	**18.1**

Economic Rent in Norway

Table 8 presents data for the value of oil and gas resources and the cost of oil and gas production annually for Norway. Figures are shown as 2000$/BOE, like the revenue figures in the previous section. The value of oil and gas resources in Norway increased by 47 percent between 1995 and 2002. At the same time, the cost of production increased significantly. In three years over the study period the cost of production exceeded the value of oil and gas resources leaving no economic rent available to government. In other years, the value of the oil and gas exceeded the cost of production leaving substantial economic rent for the government to capture. In general, a fairly high portion of economic rent was captured by the government of Norway over the study period, exceptional years are 1995 and 2000.

Table 8 Resource value, production costs and economic rent (2000$/BOE), Norway, 1995 to 2002

	1995	1996	1997	1998	1999	2000	2001	2002
Resource Value	24.8	30.1	30.1	19.9	26.9	42.8	35.3	36.3
Production Cost	12.4	14.3	14.6	29.0	59.7	12.8	12.0	118.2
Economic Rent	12.4	15.9	15.4	0.0	0.0	30.1	23.4	0.0
Rent Capture	**64%**	**80%**	**96%**	**100%**	**100%**	**65%**	**100%**	**100%**

Source: Cost figures from the 2003 Resource Report from the Norwegian Petroleum Directorate and the BP Statistical Review of World Energy; value figures from Norway's 2003 Statistical Handbook

Summary

Norway has a unique system to capture rent from oil and gas production. In contrast to the Canadian jurisdictions and Alaska, which collect the majority of oil and gas revenues from royalties, the major sources of revenue in Norway are revenues associated with the partial ownership of oil and gas resources, a special tax on oil and gas company profits and the corporate income tax. The special tax on profits, in particular, allows the Norwegian government to capture significant revenues and a high portion of economic rent.

Also unique to Norway is the existence of a carbon dioxide tax. This tax provides incentive to oil and gas companies to reduce greenhouse gas emissions and is one of the main tools used by the Norwegian government to achieve commitments for greenhouse gas emission reductions as established in the Kyoto Protocol. The carbon dioxide tax is part of the country's long-term plan to reduce greenhouse gas emissions and is an important part of the country's rent capture regime.

Regional Details: Alaska

In this appendix, we describe the methods the government uses to obtain revenues from oil and gas production in Alaska. We present quantitative estimates of revenues as well as cost and resource value figures over the study period and discuss environmental impacts associated with oil and gas production in the state. We begin with background information on oil and gas production in Alaska.

Background

In this appendix, we identify the government authorities that play a role in regulating, managing and/or facilitating oil and gas production in Alaska. For each authority, we provide a brief description of its relevant responsibilities. We also present background information on the oil and gas sector, with figures for oil and gas production, employment in the oil and gas sector, and gross domestic product associated with oil and gas production in Alaska.

Responsible Authorities

The **Division of Oil and Gas** in the **Department of Natural Resources** (DNR) is the main authority for oil and gas developments in Alaska. The Division of Oil and Gas delivers seven primary services:

1. It ensures that promising oil and gas lands are made available for competitive leasing on a timely and predictable basis, and that the state receives full value for the sale of these resources;
2. It advances innovative programs, such as exploration licensing and expanded exploration incentive credits, that promote exploration and development on both state and private lands in frontier interior basins;
3. It ensures that all royalty, rental and bonus revenues due to the state from leasing and production are received, and that shared federal royalties are received and properly allocated;
4. It ensures that the surface operations of lease- and permit-holders are conducted in an environmentally, socially and economically sound manner;
5. It advocates petroleum resource development throughout the state;
6. It develops and advocates marketing strategies for Alaska oil and gas, including negotiating royalty oil purchase agreements with in-state refineries; and,
7. It provides technical and policy support on oil and gas issues for the DNR Commissioner's and Governor's office and Alaska's congressional delegation.

Oil and Gas Production in Alaska

Oil and gas production in Alaska is centred around two main geographic areas: Cook Inlet and the North Shore. State production started in 1959 with an oil field at Swanson River in Cook Inlet. Numerous other fields became active in the 1960s and 1970s. Oil production began in the North Slope region in 1969. Prudhoe Bay on the North Shore is North America's largest oil field, accounting for about 25 percent of the oil produced in the United States.[1] Table 1 shows oil and gas production from 1995 to 2002, inclusive. As the figures indicate, total oil and gas production in Alaska declined steadily between 1995 and 2002.

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[1] Warrack, Allan A. and Russell R. Keddie. *Alberta Heritage Fund vs. Alaska Permanent Fund: A Comparative Analysis*. Edmonton, Alberta: University of Alberta, Faculty of Business.

Table 1 Oil and gas production, Alaska, 1995 to 2002 (million BOE)

PRODUCTION	1995	1996	1997	1998	1999	2000	2001	2002
Total	571	544	508	463	416	388	382	388

Source: www.dog.dnr.state.ak.us/oil/programs/royalty/production.htm

While the largest oil fields in Alaska – Prudhoe Bay and Kuparuk – are nearing the end of their lives, smaller and more numerous satellite oil and gas reservoirs are being developed and produced. The long-term picture for oil production is one of gradual decline, supplemented by smaller field oil development and gas field development in or near existing infrastructure. Oil production from the North Shore is expected to remain at current levels for at least the next eight years.

Oil and Gas Employment in Alaska

Table 2 presents direct employment figures for oil and gas production in Alaska. The table shows total employment figures for the state, as well as the share of total employment attributable to oil and gas production. The figures indicate that, while total employment in the state has increased (by 13 percent between 1995 and 2002), employment associated with oil and gas production has remained relatively constant. As a result, the portion of total employment attributable to oil and gas production has declined slightly.

Table 2 Employment associated with oil and gas production, Alaska, 1995 to 2002

EMPLOY'T	1995	1996	1997	1998	1999	2000	2001	2002
Oil and Gas	8,900	8,500	8,300	9,309	7,900	8,700	9,500	8,800
Total	262,000	263,600	268,700	275,000	277,800	283,900	289,300	295,800
% of Total	3.4%	3.2%	3.1%	3.4%	2.8%	3.1%	3.3%	3.0%

Source: Alaska Department of Labor Web site

Oil and Gas Gross Domestic Product in Alaska

Table 3 presents gross domestic product (GDP) associated with oil and gas production, total state GDP, and oil and gas GDP as a percentage of GDP generated by all industries. The figures indicate that growth of the oil and gas sector has been outpaced by growth of the state economy. While "all industries" GDP increased by 15 percent between 1995 and 2002, GDP associated with oil and gas production in Alaska declined by 4 percent. Despite this decline, the oil and gas sector constituted a significant 19 percent share of total state GDP in 2002.

Table 3 GDP associated with oil and gas production and state GDP, Alaska, 1995 to 2002 (million 2000$)

GDP	1995	1996	1997	1998	1999	2000	2001	2002[2]
Oil and Gas	8,544	9,679	9,593	6,082	6,661	8,546	7,703	8,167
All Industries	37,797	37,190	37,964	36,203	39,789	40,689	41,650	43,401
% of Total	23%	26%	25%	17%	17%	21%	18%	19%

Source: www.bea.gov/bea/regional/gsp

[2] 2002 figures for Alaska are not yet available. Oil and gas GDP is estimated based on total oil and gas production in 2002. Total state GDP is assumed to be the same in 2002 as in 2001, before accounting for inflation.

Oil and Gas Revenue Generation

In Alaska, licences convey the right to undertake exploration activities and are granted to the applicant who has committed the most money to an exploration program. The recipient of a licence must post a bond in the amount of the work commitment and pay a US$1 per acre licence fee. During the term of a licence, any portion of the licensed area may be converted to oil and gas leases, which convey the right to develop oil and gas resources and are granted through a competitive bidding process in which the highest bidder is awarded the rights to a tract of land. There is a standard annual rental fee for leases of US$1 per acre for the first year, increasing to a maximum of US$3 per acre after the fourth year.[3] Once leases are granted, oil and gas producers are liable for royalties and other taxes payable to the State of Alaska. Table 4 lists the fees used to obtain revenues from oil and gas producers in Alaska.

Table 4 Key means of revenue generation, Alaska

COMPONENT	KEY ATTRIBUTES
Oil and Gas Royalties	The State of Alaska can take its share of oil production in kind or in value. When the government takes its royalty share in kind (RIK), it assumes possession of the gas and oil. The Commissioner of Natural Resources may sell the RIK gas or oil in a competitive auction or through a non-competitive sale negotiated with a single buyer. When the government takes its royalty in value (RIV) the lease holders remit cash payments. The royalty rate varies, according to the lease agreement, from 5% to 60%, but is most often 12.5%.
Bonus Bids	Alaska uses a bonus bid system to lease certain state-owned lands for oil and gas exploration and development. Each sale involves a specific group of leases. Sealed bids are accepted for each lease offered in the sale, and the highest bid acquires exploration and development rights, subject to the terms of the lease.
Oil and Gas Settlements	Oil and gas companies must pay these fees to compensate for incorrect fees and royalties paid previously.
Property Tax	The Property Tax Group is responsible for assigning a value to all petroleum exploration, production and pipeline transportation property in Alaska. The oil and gas property tax rate is 2% of the assessed value.
Corporate Income Tax	Alaska levies a corporate net income tax based on federal taxable income with certain Alaska adjustments. Tax rates are graduated from 1% to 9.4% in increments of $10,000 of taxable income. The 9.4% maximum rate applies to taxable income of $90,000 or more.
Production Taxes	All oil and gas production in Alaska, except the federal and state royalty share, is subject to the state's production taxes. These taxes comprise the oil and gas production tax and a hazardous release surcharge levied only on oil. For the oil production tax, the tax rate depends on the age and level of production of the well. The statutory tax rate for oil is 12.25% of its value at the point of production for the first five years of field production, and 15% thereafter. There is a minimum tax of US 80 cents per taxable barrel.
Rents	Rents are paid on leases, which permit exploration and development.

[3] See www.dog.dnr.state.ak.us/oil/programs/licensing/licensing.htm.

Table 4 Continued

COMPONENT	KEY ATTRIBUTES
Exploration Licences	An area selected for an Exploration Licence must be between 10,000 and 500,000 acres. A licence is awarded to the applicant who has committed the most money to an exploratory program. The recipient of a licence must post a bond in the amount of the work commitment and pay a US$1/acre licence fee.
Federal Payments	Oil and gas corporations operating in Alaska are subject to federal corporate income tax. They also pay royalties on federal lands and on the Outer Continental Shelf Offshore Alaska.

As in the Canadian regions, oil and gas producers in Alaska benefit from a number of deductions and credits designed to facilitate and encourage oil and gas production in the state. In Alaska, there are incentives related to exploratory wells, productivity, discovery wells and shallow wells.

Table 5 Key deductions and credits related to oil and gas, Alaska

COMPONENT	KEY ATTRIBUTES
Exploration Incentive Credit (EIC) Program I	Credits, up to 50% of costs, are available for drilling exploratory wells and geophysical work on state-owned land.
Exploration Incentive Credit (EIC) Program II	EICs, up to 25% of costs, are available for exploratory drilling, drilling a strategraphic test well and geophysical work on land in the state that is not state-owned.
Royalty Reductions	If a field or pool has not previously produced, the royalty can be lowered to 5%. For producing fields or pools, the royalty may be reduced to a minimum of 3%.
Discovery Royalty	This measure permits reduced royalties for wells in the Cook Inlet sedimentary basin that have discovered oil or gas in a previously undiscovered oil or gas pool.
Shallow Gas Leasing	Non-competitive leases are available to explore for and develop natural gas[4] reservoirs if the field is within 3,000 feet of the surface. Under this program, there is no bonus payment and annual rental payments remain at the minimum level.
Cook Inlet Royalty Reduction	This program grants a 5% temporary royalty on the first 25 million barrels of oil and the first 35 billion cubic feet of gas produced in the first 10 years of production from six specified fields in the Cook Inlet sedimentary basin.

Quantitative Results of Revenue Generation

Table 6 demonstrates the trend in revenue generation from oil and gas producers in Alaska. The major sources of revenue were royalties, especially natural gas royalties, and income taxes. Total revenue generation declined by 39 percent between 1995 and 2002.

[4] Also applies to coalbed methane.

Table 6 Revenue from oil and gas production, Alaska, 1995 to 2002 (million 2000$)

REVENUE SOURCE	1995	1996	1997	1998	1999	2000	2001	2002
Royalties, Bonus Bids and Rents[5]	1,437	1,316	1,534	1,077	784	1,566	1,654	1,305
Oil and Gas Settlements	2,692	825	835	628	115	669	92	138
Corporate Income and Other Taxes	672	695	810	717	654	617	879	681
Production Tax	1,210	1,136	1,317	849	578	1,016	1,025	754
Federal Income Tax[6]	1,982	1,876	1,857	1,909	2,024	1,880	1,894	1,974
TOTAL	**7,993**	**5,847**	**6,352**	**5,180**	**4,155**	**5,749**	**5,544**	**4,852**

Table 7 compares trends in revenue generation with production to determine if the Alaska government is capturing relatively more or less revenue today than in 1995. The figures in the table show that both revenue and production declined between 1995 and 2002. More specifically, between 1995 and 2002, revenue decreased by 39 percent and oil and gas production declined by 32 percent. It is not surprising that revenue per unit of oil and gas produced also declined between 1995 and 2002, from $13.3/BOE to $10.5/BOE.

Table 7 Revenue generation and production, Alaska, 1995 to 2002 (million 2000$)

SUMMARY	1995	1996	1997	1998	1999	2000	2001	2002
Revenue (million 2000$)	7,993	5,847	6,352	5,180	4,155	5,749	5,544	4,852
Production (million BOE)	571	544	508	463	416	388	382	388
Revenue/Production (2000$/BOE)	**13.3**	**10.5**	**12.2**	**10.5**	**8.7**	**13.7**	**13.0**	**10.5**

Economic Rent in Alaska

Table 8 presents data for the value of oil and gas resources and the cost of oil and gas production annually for Alaska. Figures are shown as 2000$/BOE, like the revenue figures in the previous section. The value of oil and gas resources in Alaska increased by 58 percent between 1995 and 2002. At the same time, the cost of production increased by 92 percent. The government of Alaska captured a high level of economic rent in every year over the study period. This was the case whether there was relatively little or even no economic rent available or whether significant rent was available for capture.

[5] Includes federal royalty payments.

[6] This is the best available information. The Alaska Revenue Department estimates that oil and gas producers in Alaska have paid US$1.3 billion per year in federal income taxes since 1990.

Table 8 Resource value, production costs and economic rent (2000$/BOE), Alaska, 1995 to 2002

	1995	1996	1997	1998	1999	2000	2001	2002
Resource Value	17.5	18.7	23.5	20.9	16.2	24.8	31.4	27.6
Production Cost	16.6	20.2	11.5	17.5	19.3	16.8	16.7	31.9
Economic Rent	0.9	0.0	12.0	3.4	0.0	8.0	14.7	0.0
Rent Capture	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**88%**	**100%**

Source: Value figures from Personal communication with Alaska government

Summary

Alaska has experienced a decline in oil and gas production since 1995. It is not surprising, therefore, that the amount of revenue obtained in the state has also declined since 1995. While oil and gas production declined by 32 percent between 1995 and 2002, over the same period the amount of revenue decreased by 39 percent. The fact that revenue and production have declined together explains why the amount of revenue per unit of production has remained relatively constant over the study period. In some years it is obvious that increased revenue is compensating for relatively lower production rates so revenue per unit of production does not vary significantly. For example, revenues obtained in 1996 and 2000 were fairly similar, yet the amount of oil and gas production associated with those revenues was much smaller in 2000 than in 1996. The higher revenues in 2000, despite lower production levels, are due to higher prices for oil and gas in 2000 relative to 1996. Despite swings in commodity prices, the government of Alaska was successful at capturing a high degree of economic rent in every year over the study period.

Exchange Rates

Table 0-1 The following Canadian dollar equivalents were used in this analysis (CAD$)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
Alaska	1.4034	1.3645	1.3708	1.4297	1.5315	1.4465	1.4988	1.5920
Norway	0.2074	0.2200	0.2149	0.1940	0.2018	0.1803	0.1710	0.1780