

# 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.<sup>1</sup> 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.<sup>2</sup>
2. The **Alberta Energy and Utilities Board** regulates exploration, production, processing, transmission and distribution of energy resources within the province.<sup>3</sup>
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.<sup>4</sup>
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.<sup>5</sup>
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.<sup>6</sup>

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<sup>1</sup> Canadian Association of Petroleum Producers. See [www.capp.ca](http://www.capp.ca).

<sup>2</sup> Government of Alberta, Ministry of Energy. *2002/03 Annual Report*.

<sup>3</sup> Op. cit.

<sup>4</sup> Op. cit.

<sup>5</sup> Op. cit.

<sup>6</sup> 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.<sup>7</sup>

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)**

<b>PRODUCTION</b>	<b>1995</b>	<b>1996</b>	<b>1997</b>	<b>1998</b>	<b>1999</b>	<b>2000</b>	<b>2001</b>	<b>2002</b>
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
<b>Total</b>	<b>1,341</b>	<b>1,393</b>	<b>1,394</b>	<b>1,398</b>	<b>1,412</b>	<b>1,402</b>	<b>1,359</b>	<b>1,329</b>

*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.<sup>8</sup> 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.

<sup>7</sup> Canadian Association of Petroleum Producers Web site. See [www.capp.ca](http://www.capp.ca) for details.

<sup>8</sup> 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."<sup>9</sup> 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.<sup>10</sup> Companies are granted the rights to explore for and develop petroleum and natural

<sup>9</sup> Government of Alberta, Ministry of Energy. *2002/03 Annual Report*.

<sup>10</sup> See [www.energy.gov.ab.ca/com/Tenure/Introduction/Tenure.htm](http://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.<sup>11</sup> 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 <sup>12</sup> ranges between 15% and 30%. The Crown royalty rate for old gas <sup>13</sup> 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. <sup>14</sup> 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. <sup>15</sup> 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.

<sup>11</sup> Alberta Department of Energy. *Alberta's Royalty Regime*. Presentation, September 15, 2003.

<sup>12</sup> 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.

<sup>13</sup> Gas that does not qualify as new gas.

<sup>14</sup> The age definitions are the same for ethane as for natural gas.

<sup>15</sup> The age definitions are the same for pentanes plus as for natural gas.

**Table 4 Continued**

<b>COMPONENT</b>	<b>KEY ATTRIBUTES</b>
Methane Royalty	The Crown royalty rate for methane is price-sensitive and distinguishes between old methane and new methane. <sup>16</sup> 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**

<b>COMPONENT</b>	<b>KEY ATTRIBUTES</b>
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.

<sup>16</sup> The age definitions are the same for methane as for natural gas.

**Table 5 Continued**

<b>COMPONENT</b>	<b>KEY ATTRIBUTES</b>
Reactive Well Royalty Exemption	A royalty exemption on the first 8,000 m <sup>3</sup> of oil produced from wells that have been closed for 24 production months.
Third Tier Exploratory <sup>17</sup> 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 <sup>18</sup> by capping royalty rates at 5% for up to 16,000 m <sup>3</sup> 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 <sub>2</sub> 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 <sub>2</sub> 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. <sup>19</sup>

<sup>17</sup> A third-tier exploratory well is an oil or oil sands well spudded after September 30, 1992.

<sup>18</sup> Eligible wells cannot produce more than 121 m<sup>3</sup> in any month during the qualifying period, and average monthly production must be 73 m<sup>3</sup> or less during the last six months of the qualifying period.

<sup>19</sup> 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<sup>20</sup>. 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 <sup>21</sup>	1995	1996	1997	1998	1999	2000	2001	2002
Natural Gas Royalty <sup>22</sup>	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 <sup>23</sup>	836	1,914	773	723	794	1,762	2,103	3,508
Royalty Tax Credit	(325)	(319)	(257)	(239)	(259)	(188)	(141)	(103)
<b>TOTAL</b>	<b>4,219</b>	<b>4,469</b>	<b>4,389</b>	<b>4,339</b>	<b>3,020</b>	<b>5,830</b>	<b>11,600</b>	<b>9,063</b>

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
<b>Revenue/Production (2000\$/BOE)</b>	<b>3.1</b>	<b>3.2</b>	<b>3.1</b>	<b>3.1</b>	<b>2.1</b>	<b>4.2</b>	<b>8.5</b>	<b>6.8</b>

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

<sup>20</sup> 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.

<sup>21</sup> Some of the items that appear in Table 4 have been combined for the purposes of this table.

<sup>22</sup> Includes gas by-products.

<sup>23</sup> 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
<b>Oil Sands as a % of Total</b>	<b>9%</b>	<b>13%</b>	<b>16%</b>	<b>7%</b>	<b>3%</b>	<b>11%</b>	<b>8%</b>	<b>4%</b>
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
<b>Oil Sands as a % of Total</b>	<b>12%</b>	<b>12%</b>	<b>14%</b>	<b>15%</b>	<b>15%</b>	<b>16%</b>	<b>18%</b>	<b>20%</b>

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<sup>24</sup>

- 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.<sup>25</sup> 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,<sup>26</sup> 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
<b>Rent Capture</b>	<b>89%</b>	<b>100%</b>	<b>100%</b>	<b>100%</b>	<b>35%</b>	<b>31%</b>	<b>58%</b>	<b>41%</b>

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

<sup>24</sup> Masson, Richard and Bryan Remillard. *Alberta's New Oil Sands Royalty System*. Paper presented May 2, 1996.

<sup>25</sup> Masson, Richard and Bryan Remillard. *Alberta's New Oil Sands Royalty System*. Paper presented May 2, 1996.

<sup>26</sup> 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<sup>27</sup> 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.<sup>28</sup> 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**

<b>WELLS DRILLED</b>	<b>1995</b>	<b>1996</b>	<b>1997</b>	<b>1998</b>	<b>1999</b>	<b>2000</b>	<b>2001</b>	<b>2002</b>
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
<b>Total Annual Growth</b>	<b>8,442</b>	<b>10,203</b>	<b>12,249</b>	<b>7,628</b>	<b>9,049</b>	<b>12,719</b>	<b>13,628</b>	<b>12,989</b>
<b>CUMULATIVE FOOTPRINT (hectares)</b>	<b>93,042</b>	<b>103,245</b>	<b>115,494</b>	<b>123,122</b>	<b>132,171</b>	<b>144,890</b>	<b>158,518</b>	<b>171,507</b>

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](http://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.<sup>29</sup> 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.

<sup>27</sup> includes wells drilled for oil sands developments as well as conventional oil and natural gas.

<sup>28</sup> Alberta Energy and Utilities Board Statistical Series 57.

<sup>29</sup> 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
<b>Total</b>	<b>16,787</b>	<b>12,921</b>	<b>16,174</b>	<b>22,411</b>	<b>14,309</b>	<b>16,152</b>	<b>18,780</b>	<b>10,833</b>
Cumulative	207,541	220,462	236,636	259,047	273,356	289,508	308,288	319,121
<b>CUMULATIVE FOOTPRINT (hectares)</b>	<b>311,311</b>	<b>330,693</b>	<b>354,954</b>	<b>388,570</b>	<b>410,034</b>	<b>434,262</b>	<b>462,432</b>	<b>478,681</b>

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 (NO<sub>x</sub>) and sulphur dioxide (SO<sub>2</sub>). Between 1995 and 2002, annual emissions of nitrogen oxides increased by 21 percent, while annual emissions of sulphur dioxide declined by 21 percent<sup>30</sup>.

**Table 13 Emissions of NO<sub>x</sub> and SO<sub>2</sub> 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<sup>31</sup>. 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 <sub>2</sub> E	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

<sup>30</sup> Emissions associated with oil sands not included.

<sup>31</sup> 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.<sup>32</sup>

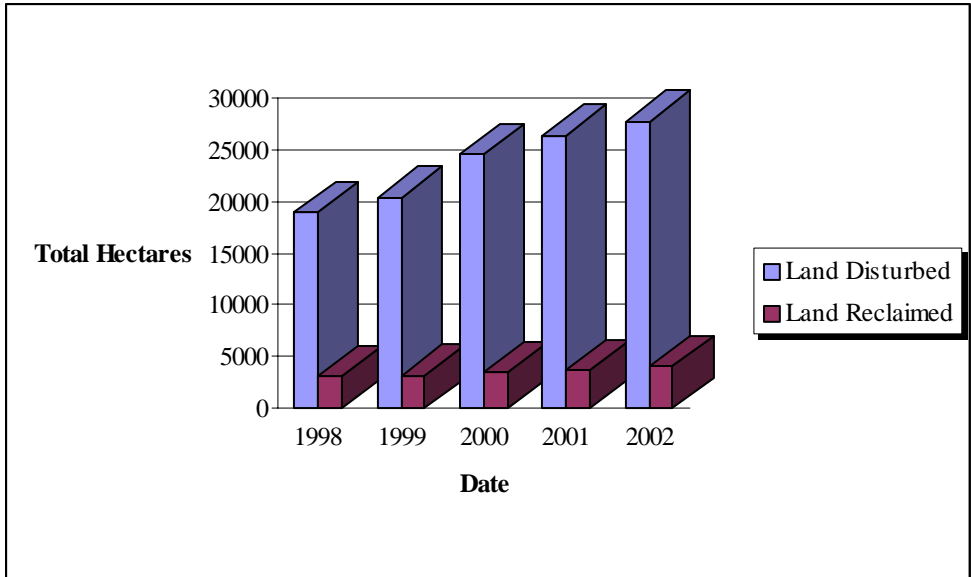
Very little land area that has been directly affected by oil sands mining operations has been restored to a condition with equivalent capability to its pre-mining state, and no oil sands operations have yet received a reclamation certificate from the Government of Alberta. When Suncor has completed mining 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<sup>33</sup>; however, this reclamation has not yet received certification from the Alberta government.<sup>34</sup> 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.<sup>35</sup>

<sup>32</sup> *The Alberta GPI Accounts: Wetlands and Peatlands*. Available at [www.pembina.org](http://www.pembina.org).

<sup>33</sup> Suncor Energy. *2003 Report on Sustainability: What's at Stake?* Available at [www.suncor.ca](http://www.suncor.ca).

<sup>34</sup> 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](http://www3.gov.ab.ca/env/protenf/landrec/definitions.html#equiv_land_capability)).

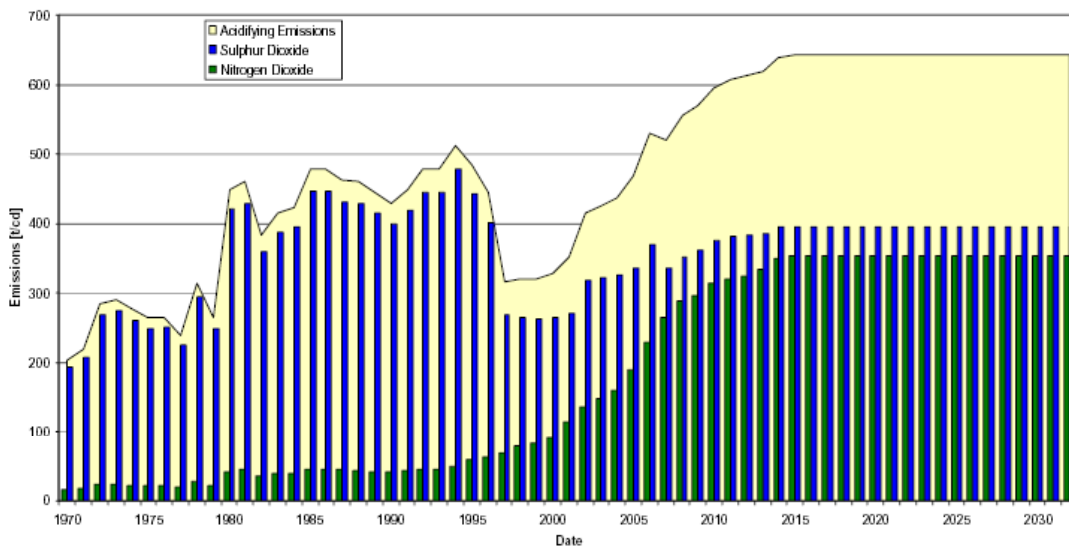
<sup>35</sup> Syncrude Canada. *2002 EH&S Report*, p. 45–46.



**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 (SO<sub>2</sub>) and nitrogen oxides (NO<sub>x</sub>). The NO<sub>x</sub>/SO<sub>2</sub> 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.<sup>36</sup>

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.<sup>37</sup> 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.<sup>38</sup>

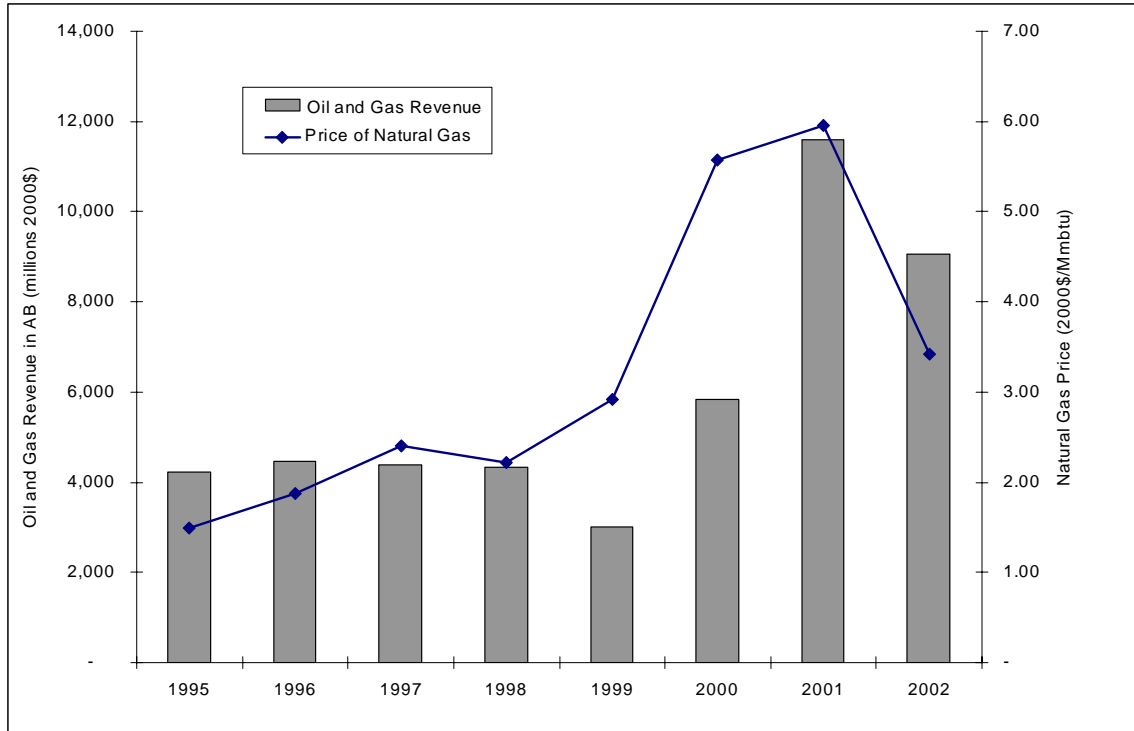
## Summary

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).

<sup>36</sup> David Suzuki Foundation. *Fuelling the Climate Crisis*, 2002. Available at [www.davidsuzuki.org](http://www.davidsuzuki.org).

<sup>37</sup> Suncor Energy. *2003 Report on Sustainability: What's at Stake?* Available at [www.suncor.ca](http://www.suncor.ca).

<sup>38</sup> Syncrude Ltd. *Sustainability Report 2002*. Available at [www.syncrude.com/investors/ar02/index.html](http://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.