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When the Government is the Landlord

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

Pembina Institute for Appropriate Development

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

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1 Introduction

Oil and gas[1] developments have played a significant role in shaping Canada's energy sector. Canada is the third-largest producer of natural gas and the ninth-largest producer of oil in the world. In 2001, British Columbia experienced record drilling and Alberta's oil sands were recently designated as the second-largest oil deposit globally. Oil and gas production is expected to increase in both Saskatchewan and British Columbia, and there is mounting pressure to develop such resources in Canada's northern territories. In light of the importance of oil and gas resources and developments in Canada presently, and the role they are expected to play in the future, the purpose of this report is to discuss and present evidence on three distinct but related concepts of significance to oil and gas developments: 1) economic rent, 2) non-renewable permanent funds, and 3) trends in environmental impacts.

As will be discussed in more detail below, governments are stewards of publicly owned oil and gas resources on behalf of citizens. In their role as "landlords," governments must collect revenues (a portion of “economic rent") from oil and gas companies in an amount that is sufficient to reflect the value of the resource development as it takes place. Non-renewable permanent funds are relevant to oil and gas developments as a means of providing stability to fiscal policy and revenues for future generations despite volatile and unpredictable oil and gas prices and depleting resources. Finally, environmental impacts are of mounting concern in Canada as oil sands developments in Alberta increase and oil and gas production accelerates in British Columbia, Saskatchewan and the territories. Each of these topics, and evidence related to their status and trends, is covered in a separate chapter in this report.

In Canada, as in other countries, the majority of oil and gas resources are "owned" by the citizens who live in the same region as the resources.[2] As such, the benefits that are realized from the exploitation of these non-renewable resources accrue to all inhabitants of the region. In general, governments lease the rights to develop oil and gas resources to companies willing to undertake exploration and production activities. In doing so, these companies incur production and exploration costs and also realize positive returns on their investment. *Economic rent* is the difference between the value of a publicly owned resource and the cost of producing those resources, including an allowance for a normal rate of return on investment.[3] Without government intervention, the financial value or wealth associated with the development of the resources would accrue to the companies undertaking the development. However, governments employ resource management policy measures, such as royalties and tenures, to ensure that a portion of the wealth associated with oil and gas production is transferred from the companies that undertake oil and gas development to the citizens of the associated region. While one could argue that governments, on behalf of citizens, should capture 100 percent of the economic rent derived from oil and gas production, in reality governments seek a balance between rent collection and objectives such as economic growth, investment in exploration and development, and the efficiency of companies. If the government of a region were to collect 100 percent of

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[1] Oil and gas developments in this report include crude oil, synthetic oil, bitumen (oil sands) oil, natural gas and gas by-products (ethane, butane, propane, pentanes and methane).

[2] A portion of oil and gas resources are privately (rather than publicly) owned. For privately owned resources, royalties are paid to individual landlords. This research project is concerned with publicly owned oil and gas resources.

[3] What is considered a “normal rate of return on investment” may vary from project to project and from company to company.

economic rent, there would be no incentive for companies to reduce operating costs through efficiency gains because the savings would not accrue to them but to the government.

Governments in Canada (provincial, territorial and federal) capture economic rent from oil and gas producers through various resource management policies, including royalties and bonus bids. As well, governments collect significant revenues through corporate income taxes. A 1999 study by the Parkland Institute[4] revealed that, between 1992 and 1997, the amount of revenue[5] obtained from oil and gas production in Alberta was substantially less per unit of oil and gas than that collected in Alaska and Norway. The study found that Alaska collected roughly 1.6 times more than Alberta in royalties and taxes for every unit of oil, natural gas and gas by-product produced. Further, the study found that Norway collected roughly 2.7 times more revenue than Alberta for every unit of oil and gas produced there.

However, the study did not explicitly measure the differences in the amount of rent available in each of these jurisdictions. It presented data showing different rates of revenue generation from oil and gas production in each of the regions, but it did not go on to analyze potential differences in the cost of producing oil and gas or the value of oil and gas resources in each of the regions. Higher revenue generation does not necessarily imply higher economic rent. Indeed, higher revenue generation may be explained by either lower production costs or a higher resource value. Without analyzing differences in costs and the value of oil and gas resources, it is not possible to say whether more or less rent was actually captured in a region. An analysis of differences in revenue generation in the context of the cost of production and the value of oil and gas resources is still required.

To build on and extend the work of the Parkland Institute in the face of oil and gas development pressures in northern Canada, plans in British Columbia and Saskatchewan to rapidly expand oil and gas developments and debates over oil, gas and oil sands royalty regimes in Alberta, in this report we investigate the status of revenue generation from oil and gas production in Alberta, as well as British Columbia, Saskatchewan, the Northwest Territories and Yukon Territory. We explore the trends in revenue generation in light of trends in oil and gas production costs and the value of oil and gas resources. In other words, we examine the trend in revenue generation in the context of economic rent. As was the case with the Parkland Institute research, the amount of revenue obtained in the Canadian regions is compared with the revenue obtained in Norway and Alaska. Likewise, the value of oil and gas resources and production costs for the Canadian regions will be compared with Alaska and Norway.

In addition to considering variations in revenue generation between regions, it is useful to examine how the revenues from oil and gas developments are being used. This is especially important in light of the fact that oil and gas prices are known to be volatile and unpredictable. As will be described later in this report, one approach to dealing with volatile oil and gas prices is to establish non-renewable permanent funds. Through these funds, jurisdictions accumulate financial wealth to offset reductions in wealth in the form of oil and gas resources. These funds are then available to smooth out boom and bust economic cycles that might result from commodity price fluctuations, to provide a long-term revenue stream to governments, and to create a store of wealth for future generations. Having a store of wealth in the future may be

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4 Macnab, Bruce, James Daniels and Gordon Laxer. *Giving Away the Alberta Advantage*. Edmonton, Alberta: Parkland Institute, 1999.

5 In this case, measured as the sum of royalties, bids, lease sales, fees and corporate income taxes.

particularly important to respond to trends in environmental impacts associated with oil and gas developments in Canada. In this report we present evidence of trends in greenhouse gas and acidifying emissions and land disturbance resulting from oil and gas developments in western and northern Canada.

The specific objectives of this study are to

- evaluate the degree to which governments in western and northern Canada capture economic rent from oil and gas developments in comparison with rent capture rates in Alaska and Norway;
- consider the need for and importance of non-renewable permanent funds, present evidence of the magnitude of such funds in Alaska and Norway, and compare the situation in those jurisdictions to Alberta's Heritage Fund; and,
- investigate trends in environmental impacts associated with oil and gas developments and highlight the significance of such trends in light of increasing oil and gas development pressures in western and northern Canada.

Report Outline

Following this Introduction, the Methodology chapter provides details on the tasks we undertook to complete this analysis. A Background chapter presents data on oil and gas production, employment and gross domestic product (GDP) for each region. The Economic Rent chapter compiles data on revenue generation, the value of oil and gas resources and the cost of production for each region. The Non-renewable Permanent Funds chapter presents evidence of the need for non-renewable permanent funds and the experience with such funds in Alaska and Norway, as well as Alberta. The Oil and Gas Environmental Impacts chapter provides information on trends in environmental impacts associated with oil and gas developments in each Canadian jurisdiction, and speaks to the need to minimize such impacts as oil and gas production in Canada increases. The final chapter, Summary and Future Directions, summarizes the evidence presented in this report, identifies areas of future research, and presents key options for moving forward on policies related to economic rent, non-renewable permanent funds and environmental impacts. The report concludes with a series of appendices, one for each jurisdiction covered in this analysis. For each region we provide a description of the economic rent capture regime, quantitative estimates of revenue generation, a discussion of the trend in revenue generation, and an assessment of environmental impacts associated with oil and gas developments.

2 Methodology

Three key avenues of investigation were undertaken as part of our research. First, to investigate economic rent capture in the various regions, in each of the jurisdictions we collected and analyzed data related to oil and gas revenues, the value of oil and gas resources, and the cost of oil and gas production. Second, to investigate the need for and importance of non-renewable permanent funds, we assessed the value of such funds in each of Alberta, Alaska and Norway. Finally, to investigate trends in environmental impacts associated with oil and gas developments in Canada, we collected data on a series of environmental indicators and measured the change in those indicators over the study period. In this chapter we describe, in detail, the specific tasks that were completed to undertake these key avenues of investigation.

Methodology Overview

To investigate economic rent capture from publicly owned lands in each of the regions, we evaluated oil and gas revenues, oil and gas production costs, and the value of oil and gas resources for each of Alberta, British Columbia, Saskatchewan, Yukon Territory, the Northwest Territories, Alaska and Norway. We began by developing jurisdictional profiles of the means by which governments in each region collect revenues from oil and gas developments. We identified and described the resource management policy measures and key fiscal policy tools used to obtain resource revenues, including royalties, leases, licences, bonus bids, income taxes and income from ownership of oil and gas resources. The fees that oil and gas companies must pay vary by region and are defined in greater detail in the jurisdictional summaries in the appendices to this report.

Our analysis captures both federal and provincial/territorial income. Due to the nature of the data available concerning federal and provincial/territorial income taxes, we have combined these sources of revenue. Payments earmarked for particular purposes or designed to cover administration costs, such as user fees, are not considered part of economic rent. This includes workers' compensation, pension and employment insurance payments. In addition, fees such as the Environmental Studies Research Levy, used to fund environmental and social studies related to oil and gas developments and payable by oil and gas companies undertaking oil and gas developments on frontier lands, were not included as part of economic rent. Such fees are instead captured as part of operating costs in each region.

Having identified the various components of revenue generation for each region, it was necessary to obtain estimates of revenue for each component, for each region, and for each year over the study period, 1995 to 2002. These estimates were then converted to comparable values using the appropriate Consumer Price Index (dollar figures are expressed in 2000$) for each region. Figures for Alaska and Norway were converted to Canadian dollars based on the currency exchange rates contained in Appendix H. Figures for total revenue generation were then assessed per unit of oil and gas production to allow for comparison across regions.

To complete this task, it was first necessary to obtain estimates for total oil and gas production in each region. This meant converting natural gas quantities (1,000 cubic metres) to barrels of oil equivalent (BOE) using a standard conversion of 1 cubic metre equals 6.292 barrels of oil equivalent. Total revenue figures in Canadian 2000$ were then divided by the total amount of oil and gas production in barrels of oil equivalent to obtain estimates of revenue collection ($) for each unit of oil and gas produced (barrels of oil equivalent) for each jurisdiction, for each year in the study period.

In addition to measuring the amount of revenues collected by governments, we obtained estimates of the value of producer sales and the cost of oil and gas developments. We obtained figures for annual expenditure on exploration, operating and capital investments. Using these figures, we estimated supply costs as per the formula in the box below.

> Annual Production (Supply) Cost=((annual exploration expenditure + annual capital investment)/annual oil and gas reserve additions) + (annual operating costs/annual oil and gas production)

These figures, referred to as production cost estimates, were also converted to Canadian 2000$ and dollars per barrel of oil equivalent using the same method described above.

Note that the economic rent results (figures for value of resource, revenues obtained and cost of production) presented in this report represent "average" figures for oil and natural gas for each region in a given year. Aggregation across regions and fuel types was necessary for ease of calculation[6] and comparison across regions. However, it is important to keep in mind that economic rent varies over time, from well to well, and by fuel type, and that the "average" figures presented in this report do mask some variation. Note that the analysis of economic rent (revenue generation, cost of production and value of resource) does not include oil sands[7].

To provide context for our analysis, we have presented background information on the oil and gas sector for each of the regions. More specifically, we considered the contribution of the oil and gas sector to other parts of the economy, including employment and gross domestic product (GDP).[8] We began by obtaining direct employment and GDP figures for the oil and gas sector for each region. We investigated the contribution of the oil and gas sector to provincial/territorial employment by measuring the portion of total employment directly attributable to the oil and gas sector between 1995 and 2002. We then calculated the share of "all industries" GDP attributable to the oil and gas sector over the same time period. This measure tells us what portion of the total economy the oil and gas sector comprises. It is a measure of the contribution of the oil and gas sector to the regional economy. The objective in completing this analysis was to discern whether the oil and gas sector in the various regions constituted a greater or lesser portion of "all industries" GDP and total regional employment in 2002 than it did in 1995.

To investigate trends in the value of non-renewable permanent funds in each of the regions, we obtained figures for the total value of such funds in Alberta, Alaska and Norway in the years between 1995 and 2002. Total value figures were converted to 2000$ for ease of comparison over time.

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[6] Much of the data did not come in a disaggregated form, so attempting to disaggregate it by fuel type, location and time would have increased the uncertainty of the results.

[7] Royalties from oil sands as well as oil sands production are considered separately in a dedicated section of this report.

[8] Gross domestic product (GDP) is the value of all goods and services in a region. Thus, oil and gas GDP is the value of goods and services produced by the oil and gas sector.

Finally, for each region we investigated trends in environmental impacts. To accomplish this, we first obtained estimates for key environmental indicators, including greenhouse gas emissions, acidifying emissions and land disturbance between 1995 and 2002 for Alberta, British Columbia and Saskatchewan. We chose these indicators because data was available in all three regions, which enabled us to compare a consistent set of trends across several regions. Figures for acidifying emissions and greenhouse gas emissions come from a recent inventory completed by Clearstone Engineering for the Canadian Association of Petroleum Producers. This inventory has figures for 1995 to 2000. Figures for 2001 and 2002 were estimated based on the relationship with production and emissions in 2000. In other words, each unit of oil and gas production was assumed to result in the same amount of emissions in 2001 and 2002 as it did in 2000.

To measure land disturbance, we employed what is commonly referred to as the "footprint" theory. This methodology converts physical estimates of development to an estimate of the amount of land impacted by a particular activity. While land impacts may include the effect of existing land uses on the suitability of land for future use, the environmental quality of the land, and wildlife habitat, the footprint analysis employed here only measures one aspect of land impact: area of land disturbed. In the context of this study, we converted the number of wellpads in place in the various regions to the total amount of land disturbed as a result of those wellpads. Wellpad clearing is a proxy for the amount of clearing associated with drilling wells. It is important to note, however, that most new wellpads will have at a minimum a winter road constructed to provide access to the wellpad. Roads are between a few hundred metres to several kilometres in length and approximately 20 metres wide. If the well produces economic quantities of oil or gas, the road will normally be converted to an all-season road and maintained for the productive life of the well. Road construction associated with wellpads is not captured in this footprint estimation. A very conservative estimate of the amount of land impacted by each wellpad, therefore, of 1 hectare was employed in this analysis.[9] Estimates of the total historical amount of land disturbed by wellpads were calculated for each year of the study period.

For each of Alberta, British Columbia and Saskatchewan, the footprint analysis was also employed to estimate land disturbance associated with oil and gas pipelines. Here the theory is that for every kilometre of pipeline constructed, there will be an associated amount of land that is disturbed. This pipeline footprint calculation, too, only captures an estimate of the amount of land disturbed, and does not, for example, infer any associated impacts on wildlife, the forestry sector, or the suitability of land for other uses. However, even estimating the amount of land disturbed by pipelines in a region can be a challenge. Depending on the diameter and location of the pipe, the size of the footprint can vary significantly. For example, the National Energy Board assumes a right of way is 18 to 20 metres for pipelines with a small diameter, but 30 metres for pipelines with a larger diameter (e.g., 36 to 42 inches). Other analyses have estimated a 25 metre width disturbance for pipelines.[10] In British Columbia, the right of way for a pipeline is a minimum of 10 metres, a maximum of 18 metres, and an average of 15 metres.[11] In this analysis, the pipeline footprint estimate is based on the average right of way for pipelines

[9] Brad Stelfox, personal communication with Mary Griffiths, January 16, 2004.
[10] Op. cit.
[11] B.C. Oil and Gas Commission, Government of British Columbia, personal communication.

in British Columbia: 15 metres.[12] Based on a width of 15 metres, the area of land impacted by 1 kilometre of pipeline is 1,000 metres x 15 metres = 15,000 m^2 = 1.5 hectares.

For Yukon Territory and the Northwest Territories, where oil and gas developments are currently not prolific but are expected to increase significantly in the future, a different approach to investigating environmental impacts was employed. In these regions, we identified and discussed the key issues that will arise over time as oil and gas development takes place, in the context of the sensitive and unique ecosystems that exist in northern Canada.

Choice of Jurisdictions

The Canadian regions chosen for this analysis represent the bulk of oil and gas developments in Canada (more than 80 percent in 2002). Meanwhile, the economic rent capture regimes in these regions are at different stages of development. In Alberta, the rent regimes are well established. In British Columbia and Saskatchewan, they are changing to encourage increased production. In Yukon Territory, the royalty regulation is still in draft form, and in the Northwest Territories where land claims are settled, First Nations and Inuvialuit are currently free to set desired royalty rates. The outcomes of this analysis will inform the evolution of economic rent capture regimes in each of the regions as they change and develop.

Timeframe

In this analysis, we assess revenues and costs from 1995 to 2002. This allows for some overlap with the work completed by the Parkland Institute, as we improve on the methodology used in their study, and at the same time brings the analysis up to date. For consistency, trends in non-renewable permanent funds and environmental indicators were investigated over the same time period.

Key Data and Information Sources

Specific sources of information and data are identified in appropriate places throughout the report. Key sources included the following:

- government contacts in the finance and energy departments of each regional government, including Alaska and Norway, as well as the Alberta Energy and Utilities Board;
- government public accounts, both provincial/territorial and federal, for the years 1995 to 2002, inclusive;
- government energy department reports, such as annual reports and business plans
- government annual budget documents;
- Statistics Canada publications and data (retrieved using CANSIM);
- Statistics Norway;
- Canadian Association of Petroleum Producers data available in its *Statistical Handbook for Canada's Upstream Petroleum Industry*;

[12] Impact from a pipeline is greatest in areas of natural habitat and forested land, where the effects may last for many years (because trees or native grasslands are affected). On agricultural land, however, the impact may only be evident for a season or two. Since we don't have a breakdown of the type of land affected by each metre of pipeline, we have chosen the average right of way as our measurement of impact.

- tax expenditure publications, such as the federal government's annual *Tax Expenditures and Evaluations* report; and,
- the Canadian Industrial Energy End-Use Data Analysis Centre.

It is also worth noting that during the early stages of this project, we identified partners in each of the Canadian regions covered in this analysis. These partners, West Coast Environmental Law, the Canadian Arctic Resources Committee, the Yukon Conservation Society and the Saskatchewan Environmental Society, have provided information, data and feedback that contributed to our research and analysis work. They also reviewed several drafts of the report. Experts in the field of economic rent have reviewed the report.

All cost figures presented in this report are in Canadian dollars, unless otherwise stated.

3 Background

This chapter presents background information on the oil and gas sectors in each of the regions. Below we demonstrate trends in production, employment and gross domestic product associated with oil and gas developments.

Trends in Production and Economic Indicators

Oil and Gas Production

Table 3-1 shows total oil and gas production for each of the regions included in this analysis. As the figures indicate, Alberta (AB) is responsible for the majority of oil and gas production in Canada, by a significant margin. Saskatchewan (SK) and British Columbia (BC) host similar amounts of oil and gas production, with the emphasis in Saskatchewan on oil and the emphasis in British Columbia on natural gas. Yukon Territory (YT) and the Northwest Territories (NWT) are currently responsible for relatively small amounts of oil and gas production. British Columbia saw the most significant increase in oil and gas production between 1995 and 2002, at 49 percent. While production in Alaska has declined, production in Norway has increased fairly significantly. In Norway, natural gas production increased by 135 percent and oil production increased by 15 percent between 1995 and 2002.

Table 3-1 Oil and gas production, 1995 to 2002 (million BOE)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	140	143	155	161	158	172	194	209
AB	1,341	1,393	1,394	1,398	1,412	1,402	1,359	1,329
SK	166	173	187	187	180	196	200	197
YT	3	3	3	3	4	4	3	2
NWT	12	12	11	11	10	12	15	14
Alaska	571	544	508	463	416	388	382	388
Norway	1,234	1,420	1,468	1,425	1,449	1,538	1,581	1,628

Source: Canadian figures from Canadian Association of Petroleum Producers; Alaska figures from the State of Alaska Web site; Norway figures from the 2003 Norwegian Petroleum Activity Fact Sheet

Oil and Gas Employment

Table 3-2 shows total direct employment figures associated with oil and gas extraction by region between 1995 and 2002. Direct employment in oil and gas extraction increased between 1995 and 2002 for all Canadian regions except Alberta, where it declined. Employment in Alaska remained relatively constant, while in Norway it declined slightly.

Table 3-2 Oil and gas extraction direct employment, 1995 to 2002

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	2,514	2,563	2,777	2,053	2,077	2,597	2,194	2,525
AB	33,027	34,303	34,327	32,134	30,882	32,220	32,277	31,041
SK	1,912	2,000	2,164	2,279	1,919	1,968	2,781	2,289
YT	11	11	12	2	1	9	7	16
NWT	436	416	399	388	352	409	497	476
Alaska	8,900	8,500	8,300	9,309	7,900	8,700	9,500	8,800
Norway	18,000	17,000	16,000	16,000	16,000	17,000	16,000	16,000

Source: Canadian figures from Statistics Canada for 1997 to 2002 and estimated for 1995 and 1996; Alaska figures from the Alaska Department of Labor and Workforce Development; Norway figures from the 2003 Norwegian Petroleum Activity Fact Sheet

The lower numbers in Norway, relative to Alberta, despite higher production values, can be largely explained by the high number of head offices located in Alberta for production throughout Canada and internationally. As well, fewer, larger firms operate in Norway, while in Alberta substantially more, smaller firms are in operation.

Table 3-3 shows direct employment per million barrels of oil and gas produced between 1995 and 2002 for each of the regions. Trends in British Columbia and Alberta are worthy of particular attention. For both of these regions, employment per unit of production declined between 1995 and 2002. In British Columbia, the decline is the result of increases in production that exceeded increases in employment. In Alberta, on the other hand, the reduction is due to declines in employment that outpaced declines in production. In other words, in British Columbia increases in production have not been matched by increases in employment opportunities.

Related to this, and of relevance to all regions, research has demonstrated that investments in renewable energy, and energy efficiency improvements in particular, can lead to significantly greater employment gains compared to investments in conventional energy (oil and gas). A survey of research in this area by the Pembina Institute found that, on average, energy efficiency investments (e.g., building retrofits) create more than 35 person years of employment per million dollars invested.[13] This is about four times as many jobs as the average for equivalent investments in energy supply: three times as many as alternative energy supply investments (e.g., solar and biomass), and five times as many as conventional energy supply investments (e.g., oil and gas). Looking outside Canada, Norway also experienced a decline in employment per million barrels of oil and gas produced, while in Alaska employment increased.

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

Table 3-3 Oil and gas extraction direct employment per million barrels of oil and gas produced, 1995 to 2002

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	17.93	17.93	17.93	12.77	13.17	15.09	11.34	12.10
AB	24.63	24.63	24.63	22.99	21.87	22.98	23.74	23.36
SK	11.55	11.55	11.55	12.19	10.68	10.02	13.91	11.60
YT	3.94	4.23	4.73	0.70	0.25	2.51	2.34	6.87
NWT	35.86	35.86	35.86	35.86	35.86	34.70	32.53	34.30
Alaska	15.58	15.63	16.34	20.12	19.01	22.41	24.89	22.66
Norway	14.34	11.97	10.90	11.30	11.32	10.73	10.18	10.07

It is also interesting to consider direct employment in oil and gas extraction in light of the total employment for a particular region. Table 3-4 presents this information. In Alberta, Yukon Territory and Alaska, oil and gas comprises a declining portion of total employment. In Saskatchewan, the share of total employment attributable to oil and gas increased slightly between 1995 and 2002. The share of total employment attributable to direct employment in oil and gas remained relatively constant in British Columbia, the Northwest Territories and Norway.

Table 3-4 Oil and gas extraction direct employment as a percentage of total regional employment, 1995 to 2002

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%
AB	2.4%	2.4%	2.4%	2.1%	2.0%	2.0%	2.0%	1.9%
SK	0.4%	0.4%	0.5%	0.5%	0.4%	0.4%	0.6%	0.5%
YT	0.09%	0.08%	0.08%	0.01%	0.00%	0.04%	0.03%	0.06%
NWT	1.8%	1.7%	1.6%	1.5%	1.6%	1.9%	2.0%	1.8%
Alaska	3.4%	3.2%	3.1%	3.4%	2.8%	3.1%	3.3%	3.0%
Norway	0.8%	0.8%	0.7%	0.7%	0.7%	0.7%	0.7%	0.7%

Oil and Gas Gross Domestic Product

Table 3-5 shows gross domestic product (GDP) associated with oil and gas for each of the regions between 1995 and 2002.[14] It is worth noting that British Columbia and Norway are the only regions that realized an increase in oil and gas GDP between 1995 and 2002. For all other regions, oil and gas GDP declined. This decline occurred despite increases in production in the Northwest Territories and Saskatchewan.

[14] These figures include coal manufacturing, as well as oil and gas extraction and petroleum manufacturing.

Table 3-5 Oil and gas gross domestic product, 1995 to 2002 (million 2000$)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	1,054	1,230	1,264	1,361	1,325	1,445	1,597	1,634
AB	18,658	18,708	18,972	19,106	19,737	17,509	17,256	17,067
SK	2,190	2,209	2,429	2,858	2,264	1,973	2,068	1,942
YT	12	13	11	6	17	20	17	11
NWT	218	208	199	186	132	195	216	170
Alaska	8,544	9,679	9,593	6,082	6,661	8,546	7,703	8,167
Norway	28,245	40,034	42,446	26,935	39,042	61,590	54,072	50,163

Source: Canadian figures from Statistics Canada; Alaska figures from the state government; Norway figures from the 2003 Norwegian Petroleum Activity Fact Sheet

Table 3-6 shows oil and gas GDP as a percentage of "all industries" GDP. For all regions except British Columbia and Norway, oil and gas GDP constituted a smaller share of total GDP in 2002 than it did in 1995.

Table 3-6 Oil and gas gross domestic product as a percentage of total GDP, 1995 to 2002 (2000$)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	1.0%	1.1%	1.1%	1.2%	1.1%	1.1%	1.2%	1.3%
AB	18%	17%	17%	17%	16%	12%	12%	12%
SK	7.6%	7.1%	7.9%	9.3%	7.2%	5.9%	6.3%	6.0%
YT	1.1%	1.1%	0.9%	0.5%	1.5%	1.7%	1.4%	0.9%
NWT	8%	7%	7%	7%	6%	8%	7%	6%
Alaska	23%	26%	25%	17%	17%	21%	18%	19%
Norway	13%	16%	16%	12%	15%	23%	21%	19%

To put oil and gas GDP in the context of oil and gas production, Table 3-7 presents oil and gas GDP per million barrels of oil and gas produced for each of the regions. The figures demonstrate that for all regions except British Columbia, Yukon Territory, Alaska and Norway, oil and gas GDP per unit of production declined. That means that in Alberta, Saskatchewan and the Northwest Territories, citizens received less economic value for each unit of oil and gas produced in 2002 than they did in 1995.

Table 3-7 Oil and gas gross domestic product per million barrels of oil and gas produced, 1995 to 2002 (2000$)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	7.52	8.60	8.16	8.47	8.40	8.40	8.25	7.83
AB	13.91	13.43	13.61	13.67	13.98	12.49	12.69	12.85
SK	13.22	12.76	12.96	15.29	12.60	10.05	10.35	9.85
YT	4.32	4.86	4.31	2.09	4.25	5.59	5.65	4.66
NWT	17.97	17.92	17.92	17.19	13.45	16.52	14.11	12.27
Alaska	14.96	17.79	18.89	13.15	16.02	22.02	20.19	21.03
Norway	22.89	28.20	28.92	18.90	26.95	40.05	34.19	30.81

Several factors explain the differences in the table above. For regions that produce mainly natural gas – such as British Columbia and Yukon Territory – the relatively lower figures reflect the lower value of natural gas as a commodity. The significantly higher value for Norway is the result of the high value of oil produced in that region.

4 Economic Rent

As we explained in the Introduction, economic rent is the difference between the value of a resource and the cost of producing that resource, allowing for a normal rate of return on investment. Thus, the amount of economic rent that is available in a region will depend on the difference between the value of the resources in that region and the cost of producing those resources. Figure 4-1 demonstrates a simple and generic breakdown of the total value of oil and gas resources. The red circle indicates the total value of economic rent (captured by some combination of royalties, taxes and bids). Once investment costs have been accounted for, and a normal rate of return on investment has been received, the actual amount of rent that is captured by governments depends on the rate of taxes, royalties and other forms of revenue generation. Any rent that is not captured through these measures accrues to oil and gas companies in the form of excess profits (the box at the top of the graph).

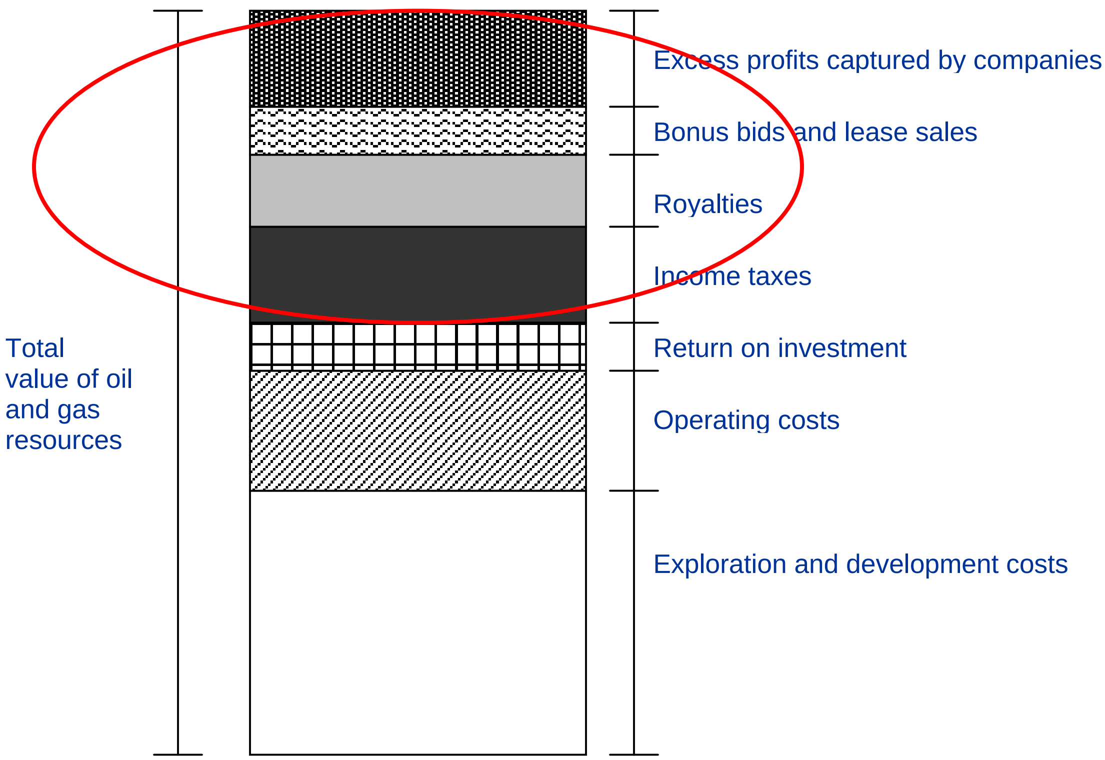

Figure 4-1 Graphical depiction of the concept of economic rent

At the most detailed level, economic rent varies not by country or by company but rather by reservoir. Thus, for every reservoir in a region, a different amount of economic rent is available for capture by the local government. The amount of rent available shifts with the price and supply of oil and gas. Depending on the relationship between the cost of production and the value of the resource for the particular reservoir, the amount of economic rent could be positive, negative or zero. While Figure 4-1 is a generic snapshot of economic rent at a particular point in time (or, in other words, a particular point on the supply curve for the particular reservoir), Figure 4-2 is a more detailed picture of economic rent that demonstrates how the amount of economic rent available varies according to supply cost (or its position on the supply curve). On the graph, projects taking place at 'A' along the supply curve have high economic rent. Those at 'B' have less economic rent. Projects at 'C' have no economic rent and are not financially viable given the market price in the graph.[15]

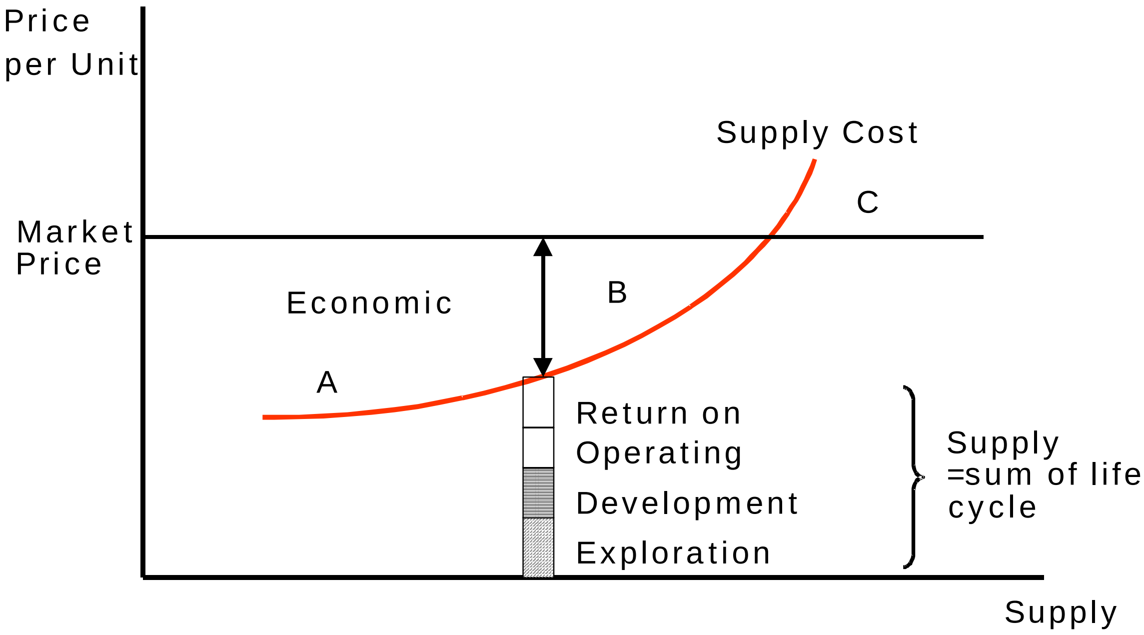

Figure 4-2 Economic rent at different levels of supply and market prices

The challenge for governments trying to capture economic rent is to figure out where on the supply curve oil and gas production is taking place, and thus how much rent is available for capture. Ultimately, it is important that the amount of revenue obtained by governments in return for the development of oil and gas resources reflects the amount of economic rent available in a particular region. This is necessary, in part, to ensure that the citizens of that region are being appropriately compensated for the development of non-renewable resources. When governments do not collect an appropriate amount of economic rent, they are providing a subsidy to oil and gas companies. This subsidy may lead to more oil and gas activity occurring than would be optimal were governments collecting sufficient rent. In other words, such a subsidy may perpetuate investment in unsustainable resource developments, perhaps at the expense of investments in renewable energy options.

The present investigation into economic rent related to oil and gas developments in western and northern Canada is timely for a number of reasons. First, in the case of Alberta, the introduction of the new generic oil sands royalty regulation in 1996 has prompted debate about the appropriateness of the royalty regime as a means of obtaining revenue from oil sands developments, as well as the level of public support provided to this intensive form of resource extraction. Research by the federal government has shown that oil sands developments receive preferential tax treatment relative to other energy options in Canada.[16] In British Columbia, the

[15] Investors may not know the financial viability of a project until after they have invested, at the end of the project's life. Part of the normal rate of return on investments is intended to reflect this risk.
[16] Commissioner of the Environment and Sustainable Development. *Report of the Commissioner of the Environment and Sustainable Development*, 2000.

question of the amount of economic rent captured by the government is particularly important because the province is experiencing record oil and gas development and authorities want to double oil and gas production by the year 2010. To advance this objective, the B.C. government has introduced a series of incentive and credit programs. Like British Columbia, the Saskatchewan government has recently introduced a number of credit and incentive programs to encourage oil and gas development in the province. In the territories, the need for this analysis is different. Royalty regulations in Yukon Territory are currently in draft form and, as they are finalized, there is an opportunity to develop protections that ensure that the citizens of the region are appropriately compensated for oil and gas developments. The Northwest Territories is currently transferring power over oil and gas resources to local authorities. In the future, the NWT government and Aboriginal governments will have opportunities to implement policies that will maximize benefits to local citizens. An investigation of economic rent will be an important component of this process. For both territories, as pressures to increase oil and gas development mount, it will become imperative to consider the amount of economic rent available. Furthermore, when investigating economic rent capture, it is useful to compare the Canadian situation to international benchmarks. To that end, in this chapter we compare revenue, value and cost data for the Canadian regions with similar data for Norway and Alaska – two jurisdictions that are known to have captured more revenues than Alberta in previous years.

Oil and Gas Revenue Comparison

Table 4-1 shows oil and gas revenues collected by governments between 1995 and 2002. Given the substantial oil and gas production that takes place in Alberta and Norway, it is not surprising to see significantly higher total revenue figures for these regions. Total revenues increased in all of the regions except Alaska, where they declined, largely because production declined, as described in the previous chapter. The most significant increases occurred in British Columbia (357 percent) and Norway (200 percent). Alberta[17] realized a 115 percent increase in the value of oil and gas revenues, while Saskatchewan realized a 56 percent increase and the Northwest Territories realized a 335 percent increase.

Table 4-1 Oil and gas revenues, 1995 to 2002 (million 2000$)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	371	532	569	430	643	1,478	1,954	1,695
AB	4,219	4,469	4,389	4,339	3,020	5,830	11,600	9,063
SK	745	757	890	651	480	979	1,314	1,166
YT	3.4	7.3	4.5	4.6	4.3	7.8	14.6	10.6
NWT	14.4	30.4	19.4	13.0	13.0	25.8	38.3	62.6
Alaska	7,993	5,847	6,352	5,180	4,155	5,749	5,544	4,852
Norway	9,805	18,105	21,675	9,730	9,664	30,291	41,270	29,396

Source: Canadian figures from public account and budget documents; Alaska figures from the state's Revenue Sources Book and Annual Financial Reports; Norway figures from the 2003 Norwegian Petroleum Activity Fact Sheet[18]

The table below shows oil and gas revenues obtained for each unit of oil and gas produced. With the exception of Alaska, the amount of revenue per unit of production increased in all

[17] Recall that the revenue figures presented here do not include royalties associated with oil sands. Oil sands royalties are presented separately in a subsequent section.

[18] You can find more detailed lists of sources in the relevant regional appendix.

regions between 1995 and 2002. As was the case with total revenues, British Columbia and Norway realized the greatest increases in revenues per unit of production between 1995 and 2002, at 207 percent and 127 percent, respectively.

Table 4-2 also reveals that the revenues collected in both Alaska and Norway exceed revenues collected in each of the Canadian regions – by a significant margin, in the case of Norway. Within Canada, British Columbia, Alberta and Saskatchewan obtained more revenues per unit of oil and gas production than the territories.

Table 4-2 International comparison of revenues from oil and gas production, 1995 to 2002 (2000$/BOE)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	2.6	3.7	3.7	2.7	4.1	8.6	10.1	8.1
AB	3.1	3.2	3.1	3.1	2.1	4.2	8.5	6.8
SK	4.5	4.4	4.7	3.5	2.7	5.0	6.6	5.9
YT	1.2	2.7	1.8	1.6	1.1	2.2	4.9	4.5
NWT	1.2	2.6	1.7	1.2	1.3	2.2	2.5	4.5
Alaska	13.3	10.5	12.2	10.5	8.7	13.7	13.0	10.5
Norway	7.9	12.8	14.8	6.8	6.7	19.7	26.1	18.1

For each region, changes in revenue can be explained by the influence of changes in oil and gas production and changes in oil and gas (commodity) prices. For example, between 1995 and 2002, commodity prices increased significantly; the price of oil increased by 44 percent and the price of natural gas increased by 160 percent. At the same time, in many regions the amount of oil and gas produced also increased. This was true for British Columbia (49 percent increase in production), Saskatchewan (19 percent increase in production), the Northwest Territories (14 percent increase in production), Yukon Territory (8 percent increase in production) and Norway (32 percent increase in production). In both Alaska and Alberta, total oil and gas production declined (by 32 percent and 1 percent, respectively). However, in Alberta, the decline in production was more than offset by the increase in prices so total revenues increased. In Alaska, this was not the case.

The figures presented in the table above tell us that for each barrel of oil and gas produced in Norway and Alaska, the respective governments collect more revenues than Canadian jurisdictions do. The amount of revenue collected, however, is not necessarily a reflection of the amount of revenue that is available. Three key factors will influence the amount of available revenue – or, in other words, the amount of economic rent that is available for capture. First, governments will be able to obtain higher revenues from oil and gas produced in regions where the value of oil and gas is also high. Thus, all other things being equal, the higher the value of the oil and gas that is produced, the higher the revenues governments are able to obtain. Second, higher revenues can be obtained in regions with lower production (capital, operating, exploration) costs. Recall Figure 4-2, which showed the amount of economic rent available under different cost conditions. There was more rent available at 'A,' where supply costs were comparatively low, than there was at 'B' or 'C.' Thus, all other things being equal, the lower the production costs, the higher the revenues governments are able to obtain. Finally, government policy influences the amount of revenues obtained from the production of oil and gas resources. For every unit of oil and gas produced, there is a certain amount of economic rent available to governments. Through the use of resource management and fiscal policies, governments capture more or less of that economic rent. Any rent that is not captured by governments accrues to oil and gas producers in the form of residual rent or excess profits. Thus, all other things being equal, the combined influence of taxes, credits, royalties and incentive programs will allow governments to collect more or less in revenues from oil and gas production.

After considering the trend in revenue generation from oil sands developments in Alberta below, we will explore trends in the value of resources and the cost of production for each region to assess whether the differences in Table 4-2 can be attributed to differences in resource value, production costs, government policies, or a combination of all of these factors.

Revenue from Oil Sands

The trend in revenues associated with oil sands production in Alberta warrants special consideration. Table 4-3 demonstrates trends in production and revenues as they specifically relate to oil sands. The table 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 4-3 demonstrate that while oil sands production is increasing (by 74 percent between 1995 and 2002), royalties from oil sands are decreasing (by 30 percent over the same time period).

Table 4-3 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 Royalties as a % of Total Royalties	**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 Production as a % of Total Production	**12%**	**12%**	**14%**	**15%**	**15%**	**16%**	**18%**	**20%**
Oil Sands Royalties/ BOE	**1.6**	**2.1**	**2.9**	**0.9**	**0.3**	**1.9**	**2.9**	**0.6**

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

Figure 4-3 graphs a portion of the information in Table 4-3. The figure shows oil sands production as a percentage of total oil and gas production in Alberta, as well as oil sands royalties as a percentage of total oil and gas royalties in the province. The figure demonstrates quite clearly that as oil sands production has increased, revenues from oil sands, in the form of royalties, have decreased. This trend is largely the result of the generic oil sands royalty regime that was introduced in 1996. Researchers expect that this trend will continue in the future. As oil sands production increases and revenues continue to decline, total revenues available to Alberta will also be reduced. This trend is of concern, especially with the increased expenditure demands anticipated in Alberta, particularly for health care, as the population ages.[19] Given the low royalties from oil sands production, according to one assessment, it "appears that, at least implicitly, the government of Alberta has opted for higher activity levels in the oil and gas industry and a lower take on each unit of production."[20]

[19] Wilson, L. S., ed. *Alberta's Volatile Government Revenues*. Edmonton, Alberta: Institute for Public Economics, 2002.
[20] Plourde, A. and Bradford Reid. "Natural Resource Revenues and the Alberta Budget" in Wilson, L. S., ed. *Alberta's Volatile Government Revenues*. Edmonton, Alberta: Institute for Public Economics, 2002.

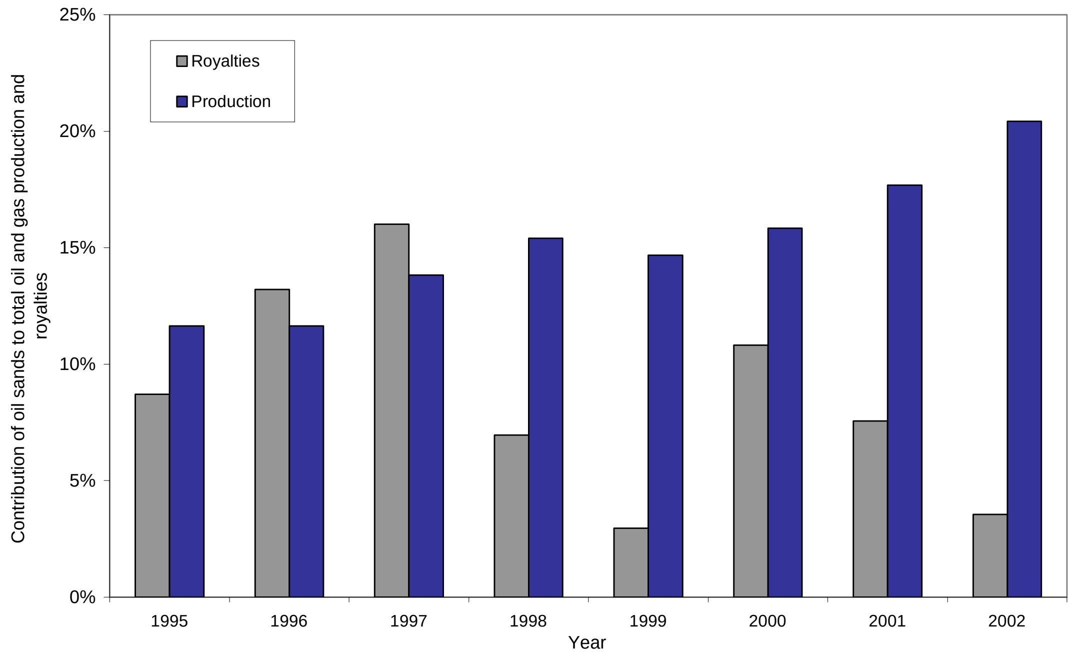

Figure 4-3 Contribution of oil sands to oil and gas production and royalties

Cost of Production and Resource Value Comparison

As was described earlier, economic rent is the difference between the value of oil and gas production and the cost of production, allowing for a normal rate of return on investment. In the previous section, we established the trends in oil and gas revenue generation for each region considered in this analysis. The evaluation of revenues revealed that Alaska and Norway collect more revenues for each barrel of oil and gas developed. However, this does not necessarily mean that Canadian governments are collecting less rent than these international regions. The differences between regions could instead be explained by differences in the value and/or the cost of production. For example, lower production costs in Norway and Alaska would allow governments to collect more revenues in those regions (in other words, more rent would be available in those regions). Likewise, if the value of oil and gas resources were higher in Alaska and Norway, governments would be able to capture higher revenues (again, this means that more rent would be available for capture).

To get a sense of how the amount of revenue obtained relates to the amount of economic rent that is available to governments, we need to consider differences in the value of oil and gas resources and production costs between regions. To the extent that differences in revenue generation cannot be explained by differences in production costs and the value of oil and gas resources, the higher revenues in Alaska and Norway can be explained by variations in government policy approaches between regions.

Figure 4-4 compares the value of oil and gas resources with figures for the cost of production for the period 1995 to 2002. For each region, the total height of the bar (grey and blue combined) is the average value of oil and gas resources over the study period. The blue portion of the bar is the average cost of production for each region, and the grey portion of the bar represents the average value of economic rent available in each region for 1995 to 2002. The graph shows that production costs are comparable in British Columbia, Alberta and Saskatchewan and are higher in the territories, Alaska and Norway. At the same time, the graph shows that the value of oil and gas resources is similar in Alaska, Alberta, the territories and Saskatchewan, relatively higher in Norway and relatively lower in British Columbia. It is the interplay between these factors (the value and cost factors) that is important when considering differences in revenue collection by governments.

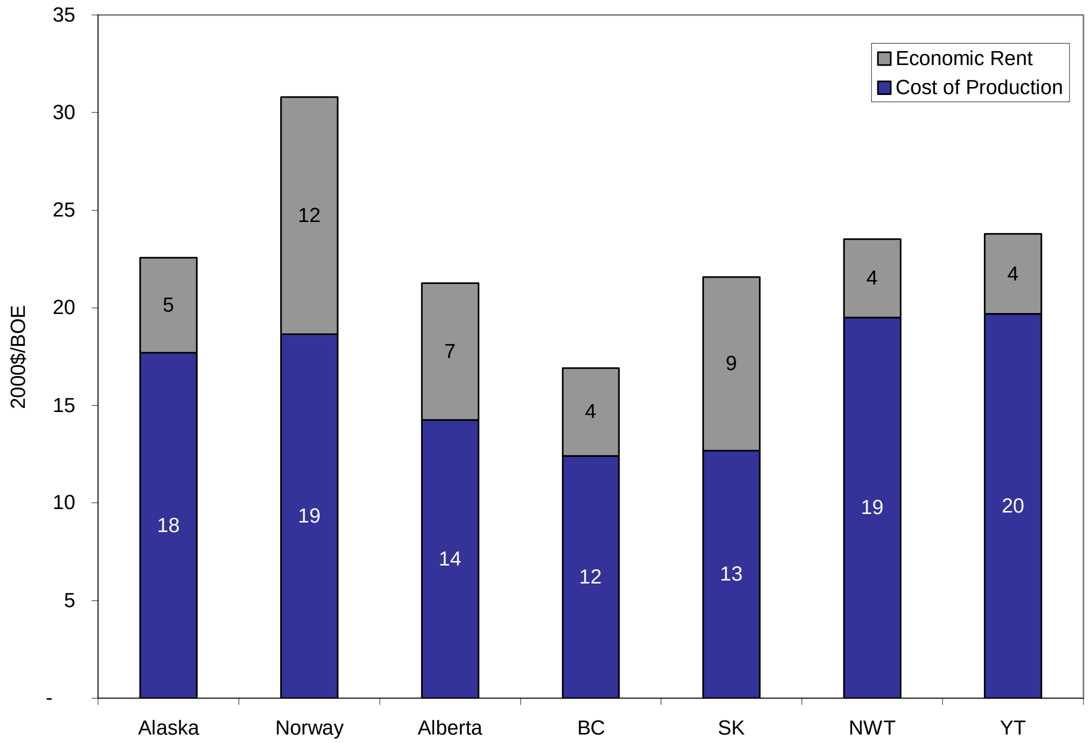

Figure 4-4 Value of oil and gas resources and cost of production, 2000$/BOE, Average 1995 to 2002

Recall that over the study period, Alaska collected more revenues from oil and gas resources than any of the Canadian jurisdictions (Table 4-2). This difference can be explained by lower production costs, higher value of the resources and/or differences in government policies. Figure 4-4 demonstrates that, in the case of Alaska, on average, the difference in revenue generation does not appear to be explained by differences in either the value of resources or production costs. In fact, Alaska was able to collect higher revenues despite also having higher production costs.

Similar to Alaska, Norway collected more revenue for the production of oil and gas over the study period than the Canadian jurisdictions did. Unlike Alaska, however, on average, the value of oil and gas resources *and* the cost of production in Norway was higher than in any of the Canadian regions. Thus in the case of Norway, it appears that on average more economic rent was available over the study period for capture by government. It is useful to consider the regional trends in the value of resources and costs of production on an annual basis to discern whether more rent was available in Norway each year or just on average. To that end, Table 4-4 shows the value of oil and gas produced for each region per barrel of oil equivalent from 1995 to 2002. The international benchmarks of Alaska and Norway are highlighted at the bottom of the table.

The table below shows that on an annual basis the value of Alaska's oil and gas resources has been fairly comparable to a number of the Canadian regions. The value of oil and gas resources in Alaska was higher than that in Canadian regions between 1995 and 1998. Between 1999 and 2002, the value of Alaska's resources was actually lower than that in several Canadian regions. In general, this indicates that the higher revenues obtained in Alaska are not justified on the basis of significantly higher values for oil and gas in this region.

In contrast to the situation in Alaska, the value of oil and gas production in Norway was higher than in the Canadian regions for every year. This implies that higher revenues obtained in Norway between 1995 and 2002 may be explained by differences in the value of oil and gas resources between these regions.

Table 4-4 Total value of oil and gas resources, 1995 to 2002 (2000$/BOE)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	9.2	10.4	11.6	10.7	14.3	30.0	29.1	19.9
AB	14.4	16.8	16.8	13.7	17.5	29.8	30.5	30.5
SK	17.7	21.5	19.1	13.5	21.5	31.7	25.1	22.5
YT	16.5	20.4	19.4	16.0	20.0	34.7	33.4	30.0
NWT	15.9	19.6	19.1	15.9	19.9	34.7	33.5	29.5
Alaska	17.5	18.7	23.5	20.9	16.2	24.8	31.4	27.6
Norway	24.8	30.1	30.1	19.9	26.9	42.8	35.3	36.3

Source: Canadian figures calculated from data in the Canadian Association of Petroleum Producers Annual Statistical Handbook*; Alaska values from personal communication, Alaska Department of Energy; Norway figures from the* Petroleum Yearbook

The differences shown in the table above are largely explained by three factors: regional production splits between natural gas and oil, the location of the resource, and quality of oil. Location does not impact the value of oil, but does have a significant influence on the value of natural gas. Generally, natural gas has a relatively lower value than oil, so regions that focus more on natural gas will generally have a lower value of production (British Columbia). In terms of the quality of oil, Saskatchewan and Alaska produce mainly relatively heavy oil, which has a lower value. Alberta has significant quantities of low-value bitumen. Meanwhile, Norway produces premium-quality, high-value oil (which explains the higher figures for Norway in the table above).

It is helpful to consider this data graphically. Figure 4-5 shows the value of oil and gas resources for each region over the study period per barrel of oil equivalent. The figure shows that the value of Norway's oil and gas is higher than values in the Canadian regions, and that the value of Alaska's oil and gas is comparable to values in the Canadian regions.

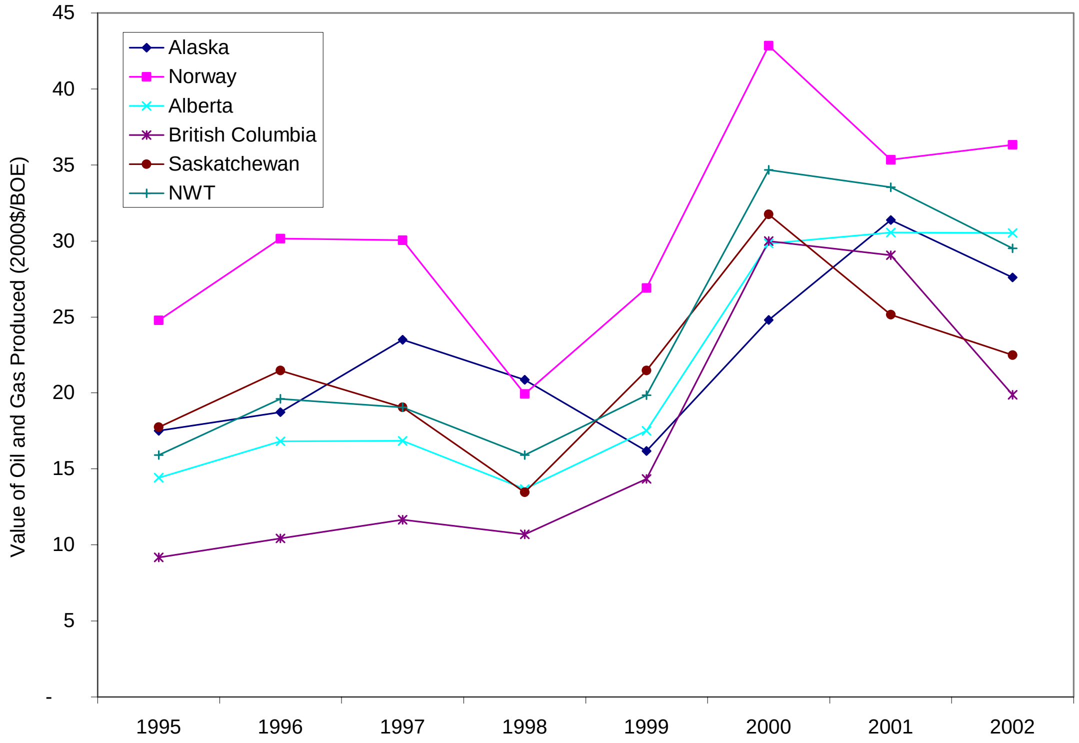

Figure 4-5 Value of oil and gas produced, 1995 to 2002, 2000$/BOE

In addition to differences in the value of resources, it is necessary to consider trends in the cost of production for oil and gas in each of the regions. Annual estimates of production costs for 1995 to 2002 are presented in Table 4-5 and include exploration costs, capital investments and operating costs calculated on a per barrel of oil and gas equivalent as per the description in the methodology chapter of this report. The figures below are net of royalties and income taxes.

Table 4-5 reveals that cost differences between the Canadian provinces and the international benchmarks of Alaska and Norway are not significant. For most years, the cost figures in Alaska and Norway are comparable or higher than the Canadian provinces. Despite this, over the 1995 to 2002 time period, Norway and Alaska collected more revenue from oil and gas production than the Canadian regions. The territories boast higher production costs than the provinces due to lower production rates and low additional reserves in those regions.

Table 4-5 Cost[21] of oil and gas production, 1995 to 2002 (2000$/BOE)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	8.3	11.6	16.1	13.4	10.6	11.9	20.4	15.3
AB	10.9	15.2	20.7	13.9	11.4	16.4	15.7	14.0
SK	8.7	12.9	14.6	11.6	16.8	10.3	12.0	14.6
YT	7.4	13.6	70.3	136.6	5.5	32.3	115.9	316.8
NWT	7.1	13.1	69.3	136.0	5.4	32.3	116.4	311.1
Alaska	16.6	20.2	11.5	17.5	19.3	16.8	16.7	31.9
Norway	12.4	14.3	14.6	29.0	59.7	12.8	12.0	118.2[22]

Source: Canadian figures from Canadian Association of Petroleum Producers Annual Statistical Handbook; Alaska figures from the United States Department of Energy and personal communication, Alaska Department of Energy; Norway figures from Norwegian Petroleum Directorate 2003 Resource Report and the BP Statistical Review of World Energy.

Figure 4-6 graphically depicts the information in Table 4-5.

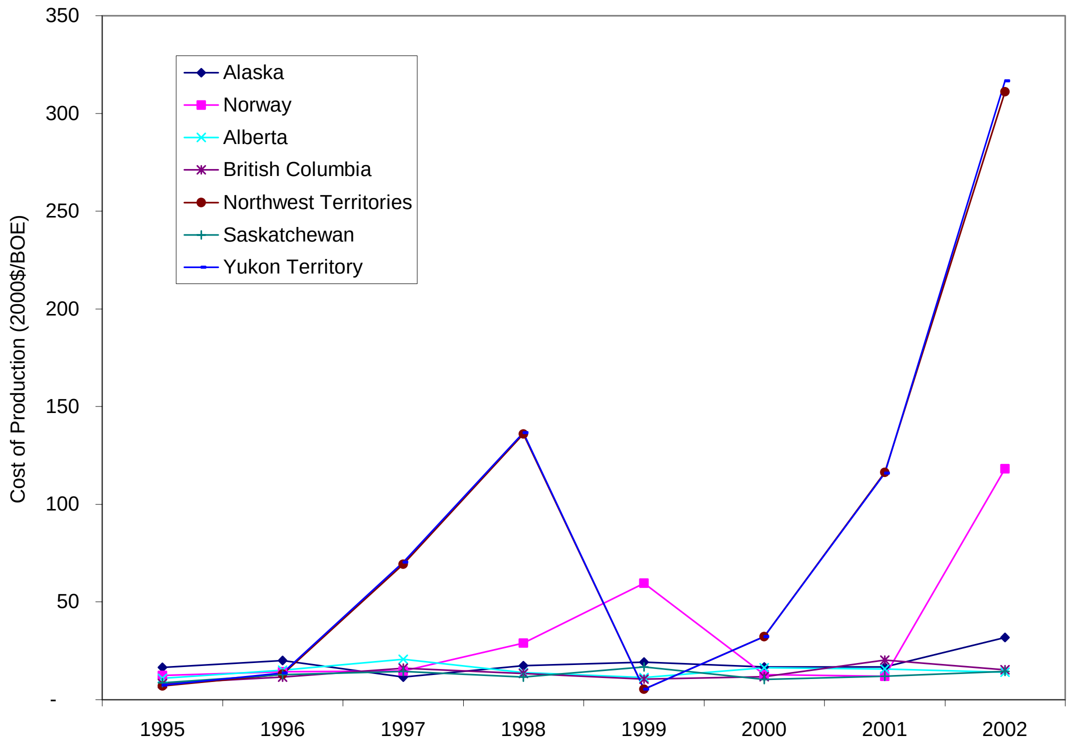

Figure 4-6 Cost of oil and gas production, 1995 to 2002 (2000$/BOE)

The preceding tables and figures have presented significant information on the trends in the value of oil and gas resources and the cost of oil and gas production for each of the regions included in this analysis, from 1995 to 2002. Investigating these trends was necessary to

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[21] Annual figures for expenditure on exploration, capital investments and operating costs are a proxy for actual supply costs.

[22] The significantly higher cost figures for 2002 in Norway and the territories are explained by low additional reserves for those regions in that year.

discern whether the lower revenues collected from Canadian jurisdictions relative to Alaska and Norway are justified on the basis of either higher production costs or lower resource values in the Canadian regions. Table 4-6 brings this information together in the form of a ratio of the value of oil and gas resources to the cost of oil and gas production for each region. The higher the value in the table, the greater the difference between the value of oil and gas resources and the cost of oil and gas production. In other words, the higher the number, the more economic rent there is available to governments, and thus the greater the opportunity for governments to collect higher revenues.

In general, the ratios below for Alaska are not significantly different than those for most of the Canadian regions. For Norway, there were several years in which more rent was available, especially between 1995 and 1997. In the latter part of the study period more rent was available in Norway than in the Canadian regions in both 2000 and 2001. In other years, the ratio for Norway was lower than that of the Canadian regions. Thus, it appears as though for some years the amount of economic rent available varied between regions while in other years it did not. Despite this, both Alaska and Norway obtained more revenues from oil and gas than the Canadian jurisdictions did in every year over the study period. This means that the differences in revenue collection are not only a result of differences in production costs and/or the value of the resources, but also a product of government policies-government policies that allowed authorities in Norway and Alaska to reap greater revenues from resource developments even in years when less rent was available.

Table 4-6 Ratio of value of production to cost of production, 1995 to 2002 (2000$)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	1.10	0.90	0.72	0.80	1.35	2.53	1.43	1.30
AB	1.33	1.11	0.81	0.98	1.54	1.82	1.94	2.18
SK	2.04	1.67	1.31	1.16	1.27	3.09	2.09	1.54
NWT	2.23	1.50	0.28	0.12	3.65	1.07	0.29	0.09
YT	2.23	1.50	0.28	0.12	3.65	1.07	0.29	0.09
Alaska	1.05	0.93	2.04	1.19	0.84	1.48	1.88	0.87
Norway	2.00	2.11	2.05	0.69	0.45	3.36	2.95	0.31

Figure 4-7 shows the trend in the ratios presented above. It is clear that there is more rent available in the territories in 1999 and that the ratio is fairly uniform for the other Canadian regions and the international benchmarks with Norway having relatively more rent available in select years.

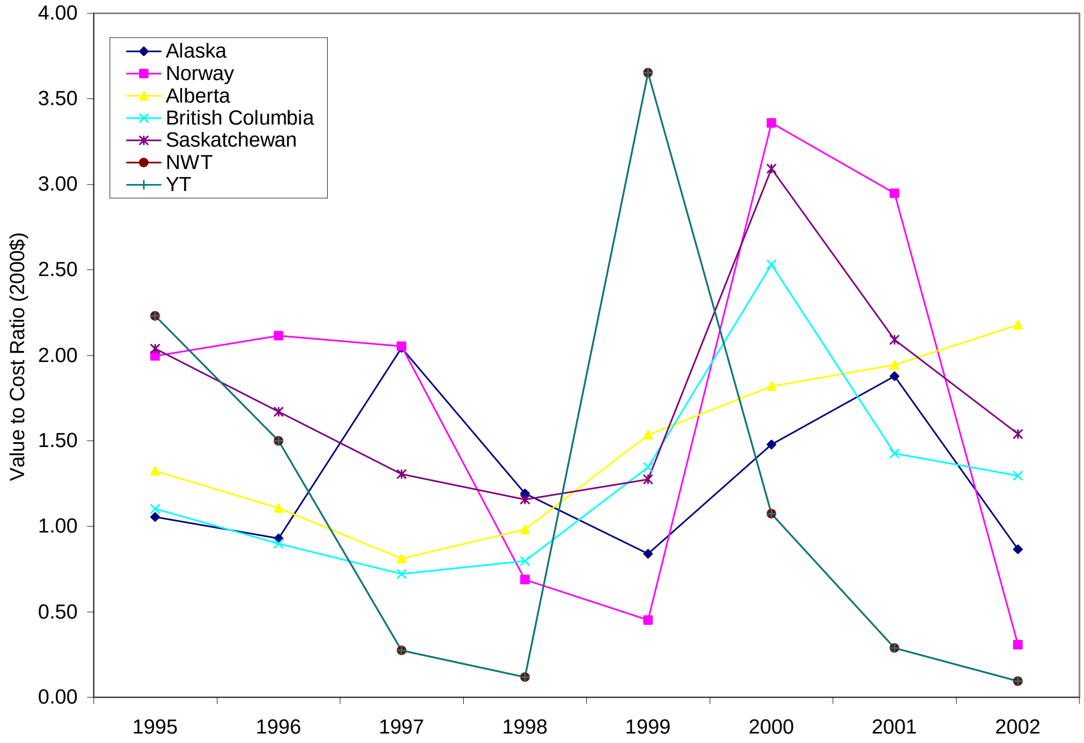

Figure 4-7 Oil and gas value to cost ratio, 1995 to 2002 (2000$)

Several conclusions arising from the above analysis are worth summarizing. The purpose of our investigation was to identify the factors that led to higher oil and gas revenue collection in Alaska and Norway than in the Canadian regions. What emerged was that in the case of Norway, the determinant factors varied over the study period. Between 1995 and 1997, more rent was available for capture in Norway than the Canadian regions. This was the case again in 2000 and 2001. In other years, the amount of rent available in Norway was less than that available in several of the Canadian regions. This implies that over the study period the Norwegian government was able to collect higher revenues not only because the value of the resource was higher or because the cost of production was lower, but also because of explicit policy action/s. The government in Norway captures rent through a combination of royalties (which are being phased out), taxes and partial ownership of oil and gas resources. The fiscal framework governing oil and gas developments in Norway was established in the mid-1970s. The aim of the policies that were put in place was "to capture most of the economic rent, to develop a Norwegian oil service industry and to reserve the bulk of the business for Norwegian companies." Research indicates that "Norway's oil policy has been a success, with large discoveries, high taxes that capture most of the economic rent for the government landowner, the development of a large oil service industry, leading competence, competitive oil companies and huge revenues."[23] A recent analysis of policies for capturing economic rent in Norway completed by Oystein Noreng[24] revealed that, indeed, there has been little change in policy over the last 30 years. The basic petroleum tax structure (royalties, corporate income tax and the special tax) has essentially been retained (with the exception of royalties being phased out)

[23] Noreng, Oystein. *Norway's Oil and Gas: Maturity and the Need for Change*, 2003.
[24] Op. cit.

since it was introduced in the mid-1970s. One assessment suggests that this consistency reveals the Norwegian government's interpretation of petroleum tax stability and robustness as a sign of strength.

In the case of Alaska, the conclusions are more straightforward. Here, governments collect higher revenues despite having higher production costs and comparable resource values. Policies allow them to achieve this.

Economic Rent Available and Capture Comparison

The investigation above considered the extent to which higher revenue generation in Alaska and Norway was justified on the basis of differences in the cost of production and/or the value of oil and gas resources in these regions. We found that the Alaskan government obtained higher revenues despite a comparable resource value and a higher cost of production. In Norway, higher revenues were the result of differences in production costs and resource values for some years but not all. Over the study period, the differences in revenue generation in Norway can be explained by a combination of differences in the value of resources, the cost of production and government policy approaches to capturing economic rent.

To take this analysis to the next level, Table 4-7 estimates the amount of rent actually available for capture[25] in each region.[26] Like the previous table, Table 4-7 shows the relatively higher rent available in Norway in certain years over the study period. On average, the amount of rent available in Alberta ($7.01/BOE) and Saskatchewan ($8.88/BOE) was similar. The lower rate of rent available in British Columbia (average of $4.49/BOE), the territories (average of $4.02/BOE for the NWT and $4.10/BOE for the YT) and Alaska (average of $4.87/BOE) is due to expenditures (exploration, capital and operating) that equalled or exceeded the value of the resources in those regions in several years over the study period. It wasn't until recently, with the higher commodity price for natural gas, that the resource value in British Columbia exceeded annual expenditures. The amount of economic rent available in British Columbia peaked in 2000 with a sudden increase in the price of natural gas. In 2001, the amount of rent available in British Columbia remained fairly high, but in 2002 a drop in the price of natural gas led to a decline in the value of gas resources in British Columbia. This, combined with high expenditures, led to an overall drop in the amount of rent available in the province.

[25] Calculated as the difference between the value of oil and gas resources and the cost of production in each region for each year. A portion of this available revenue would stay with industry in the form of profits.

[26] The zero values in the table represent cases where the costs were equal to or exceeded the value of the resource.

Table 4-7 Economic rent available[27] by region, 1995 to 2002 (2000$)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	0.8	0.0	0.0	0.0	3.7	18.1	8.7	4.6
AB	3.5	1.6	0.0	0.0	6.1	13.4	14.8	16.5
SK	9.0	8.6	4.5	1.8	4.6	21.5	13.1	7.9
NWT	8.8	6.5	0.0	0.0	14.4	2.4	0.0	0.0
YT	9.1	6.8	0.0	0.0	14.5	2.4	0.0	0.0
Alaska	0.9	0.0	12.0	3.4	0.0	8.0	14.7	0.0
Norway	12.4	15.9	15.4	0.0	0.0	30.1	23.4	0.0

Now that we know the amount of rent available in each region over the study period, we can analyze how much of that rent was actually captured by governments through royalties, taxes, lease sales, etc. This is the crux of this study's international comparison of economic rent capture. Table 4-8 shows government revenues (Table 4-2) as a percentage of rent available (Table 4-7). In other words, the table below shows revenue generation as a portion of the amount of economic rent available for capture to a maximum of 100%[28].

Table 4-8 Portion of rent captured by governments, 1995 to 2002

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	100%	100%	100%	100%	100%	47%	100%	100%
AB	89%	100%	100%	100%	35%	31%	58%	41%
SK	50%	51%	100%	100%	58%	23%	50%	75%
YT	13%	40%	100%	100%	8%	91%	100%	100%
NWT	13%	40%	100%	100%	9%	91%	100%	100%
Alaska	100%	100%	100%	100%	100%	100%	88%	100%
Norway	64%	80%	96%	100%	100%	65%	100%	100%

The table reveals that Norway and Alaska consistently obtained a greater portion of the economic rent available to them than most western and northern Canadian regions did. It is interesting to note the trend in Alberta, where the portion of rent captured has been lower in recent years. Figure 4-8 simplifies the trends presented above and considers the average portion of rent captured by governments over the study period.

[27] Value of oil and gas resource minus cost of oil and gas production.

[28] Recall that we have measured rent as the difference between the value of the resource and the cost of production. Thus, in this instance, we would not expect governments to capture 100% of the available revenue as that would imply zero profits for companies. We expect however, for the countires to be relatively similar given that we have accounted for differences in the cost of production and the value of the resources on a regional basis.

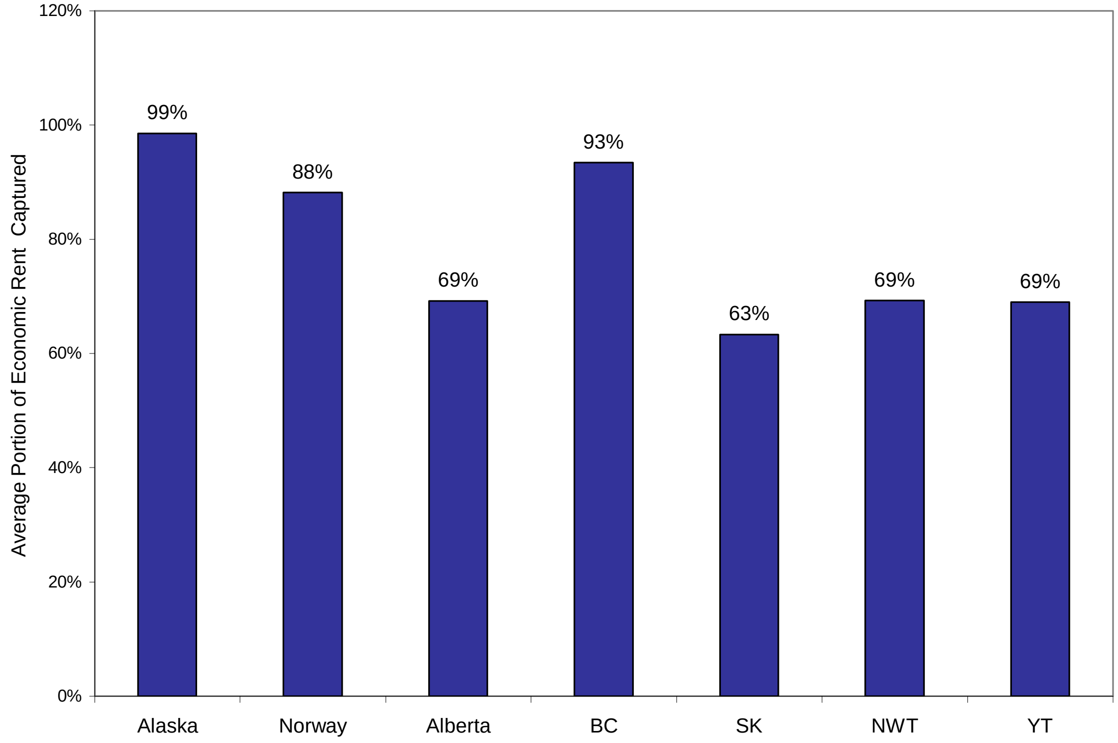

Figure 4-8 Average portion of economic rent captured in each region, 1995 to 2002

It is clear that relative to these international benchmarks, and with the exception of British Columbia, oil and gas producing regions in western and northern Canada did not capture the same level of rent. In other words, given the amount of economic rent available for capture in each region, governments in Alberta, Saskatchewan, Yukon Territory and the Northwest Territories are not obtaining the same level of compensation for each unit of oil and gas produced. In the case of British Columbia, the figure above demonstrates that between 1995 and 2002, the government captured a very high level of economic rent. It is necessary to note however, that since 2002 the BC government has implemented a number of credit and incentive programs that may have lead or may lead to a decline revenue over time. Governments in Alaska and Norway have implemented policies that allow them to capture a greater portion of the economic rent available in their respective regions. Note that capturing 100% of available revenues is not the ultimate objective. A portion of available revenues need to stay with companies in the form of profits to provide incentive for them to operate efficiently and to maintain viability. In the next section, we consider some of the key differences in policy approaches that could explain the higher revenue generation in Alaska and Norway relative to the Canadian jurisdictions.

Revenue Generation and Policy Features

The appendices of this report provide detailed information about the means governments use to obtain revenues from oil and gas production. For each region, the components of revenue generation are described in depth, and the various credit and incentive programs available to oil and gas companies are presented. The Canadian regions and Alaska and Norway all use a system of taxes and royalties, combined with credits and incentive programs, to obtain revenues from oil and gas production. However, much of the discrepancy in revenue generation between the Canadian regions and the international benchmarks is due to differences in policy approaches to revenue generation. While an in-depth assessment of the specific policy features that lead to higher revenue generation is beyond the scope of this study, some of the key differences in policy approaches between jurisdictions are worth mentioning as factors that have led to higher rent capture.

1. **Norway's "special tax" captures significant revenues from oil and gas.** One of the major measures that the Norwegian government employs to obtain revenues from oil and gas production in the country is a special tax that has been in place since 1992. This tax is explicitly designed to capture the excess profits from oil and gas companies and, when combined with the partial ownership of oil and gas resources in the country, allows the government to collect significant revenues in years of high commodity prices. The rate of the tax is 50 percent.

2. **Norway has a direct interest (partial ownership) in oil and gas operations in the country.** By having a direct interest in the country's oil and gas developments, Norway reaps significant revenues through associated dividends, especially in years of high commodity prices and significant oil and gas profits. This policy, combined with the special tax described above, ensures that significant excess profits associated with oil and gas developments do not accrue to oil and gas companies but are instead captured by the government and transferred to the citizens of Norway.

3. **Alaska captures rent through its production tax.** In addition to income taxes, royalties, rents and bonus bids, the Alaskan government obtains revenues from a production tax. Like the special tax in Norway, this tax allows the government to capture revenues from oil and gas developments that would otherwise accrue to oil and gas companies.

4. **The Canadian regions rely heavily on royalties.** Depending on the way they are designed, royalties on their own may not be the best policy tool for capturing economic rent. Royalties that are calculated as a percentage of the value of oil and gas production will only ever capture a constant portion of the economic rent available.[29] The focus in the Canadian regions on royalties may limit the amount of economic rent that governments there can capture. In addition, royalty rates in Alaska are higher than they are in the Canadian regions. A comparison of the credit and incentive programs in each of the regions (see appendices) reveals that Alaska and Norway also have fewer credit and incentive programs in place than the Canadian jurisdictions do. This, too, could allow governments in Alaska and Norway to capture more rent than the Canadian regions.

5. **Revenues from oil sands in Alberta are low.** Finally, the oil sands are worthy of mention. Between 1995 and 2002, oil sands production increased significantly in Alberta (by 74 percent). Over the same time period, however, the amount of revenue received from oil sands royalties declined (by 30 percent). The Government of Alberta collects much lower revenues from oil sands than from natural gas and conventional oil. As the share of total production attributable to oil sands continues to increase (between 1995

[29] When combined with aggressive bidding processes, royalties can be a more successful means of capturing economic rent.

and 2002, the share of total production attributable to oil sands in the province increased by 69 percent), the relatively lower royalties obtained from oil sands will lead to a decline in total revenue generation in the province.

These factors likely contribute to governments in Alaska and Norway obtaining higher revenues from oil and gas developments than most Canadian governments (except British Columbia). Given the volatile and unpredictable nature of oil and gas prices, which will be discussed in the next chapter, policies that allow governments to increase revenue generation in times of higher commodity prices are key.

5 Non-renewable Permanent Funds

The amount of economic rent available in a region depends in part on the value of the resources in that region. The value of resources, in turn, depends on the amount of production that takes place and the prices associated with that production. Recall the trends in revenue generation between 1995 and 2002 (Table 4-2). For all regions, except the Northwest Territories and Alaska, revenue amounts peaked in 2001. This peak is largely the result of the drastic increases in the price of oil and gas, especially natural gas, that took place during that period of time. Revenue generation in Alaska peaked in 2000, which is not surprising given that production in Alaska is dominated by oil and the price of oil peaked in 2000. Because the royalty regimes in the regions covered by this analysis are sensitive to changes in price (as described in detail in the regional appendices), the amount of revenues obtained by governments will change from year to year, depending on changes in oil and gas prices. Figure 5-1 shows the trend in commodity prices (oil and natural gas) between 1995 and 2002.

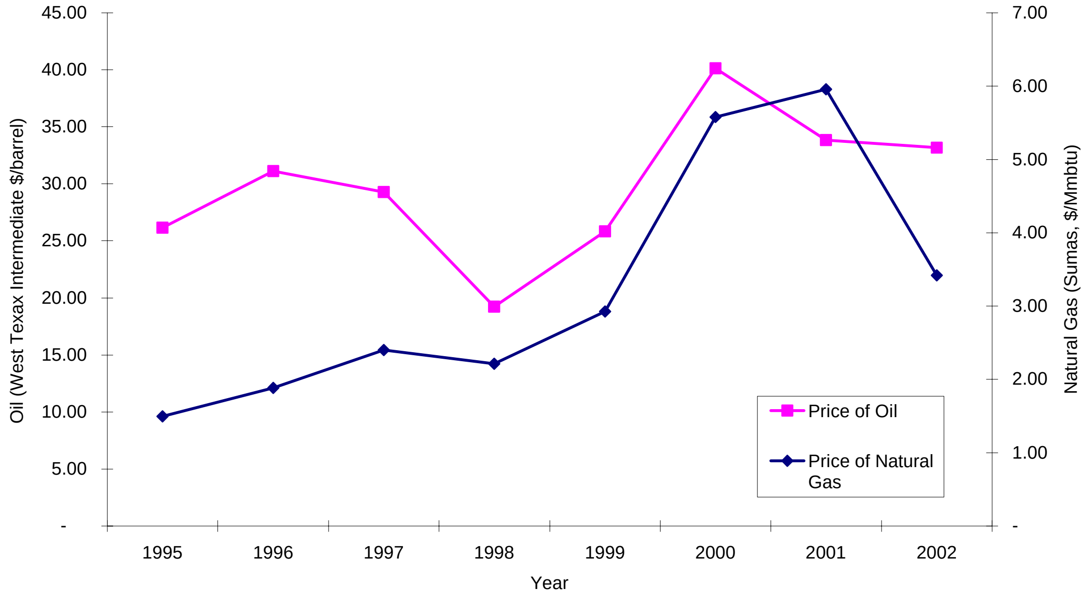

Figure 5-1 Oil and gas prices, 1995 to 2002, 2000$

Figure 5-2 demonstrates the strong link between commodity prices and oil and gas revenues by illustrating the trends in natural gas prices and the value of resource revenues from oil and gas production in Alberta (similar graphs for other regions are included in the appendices). The figure demonstrates that as the price of natural gas has increased, so, too, has the value of oil and gas revenues.

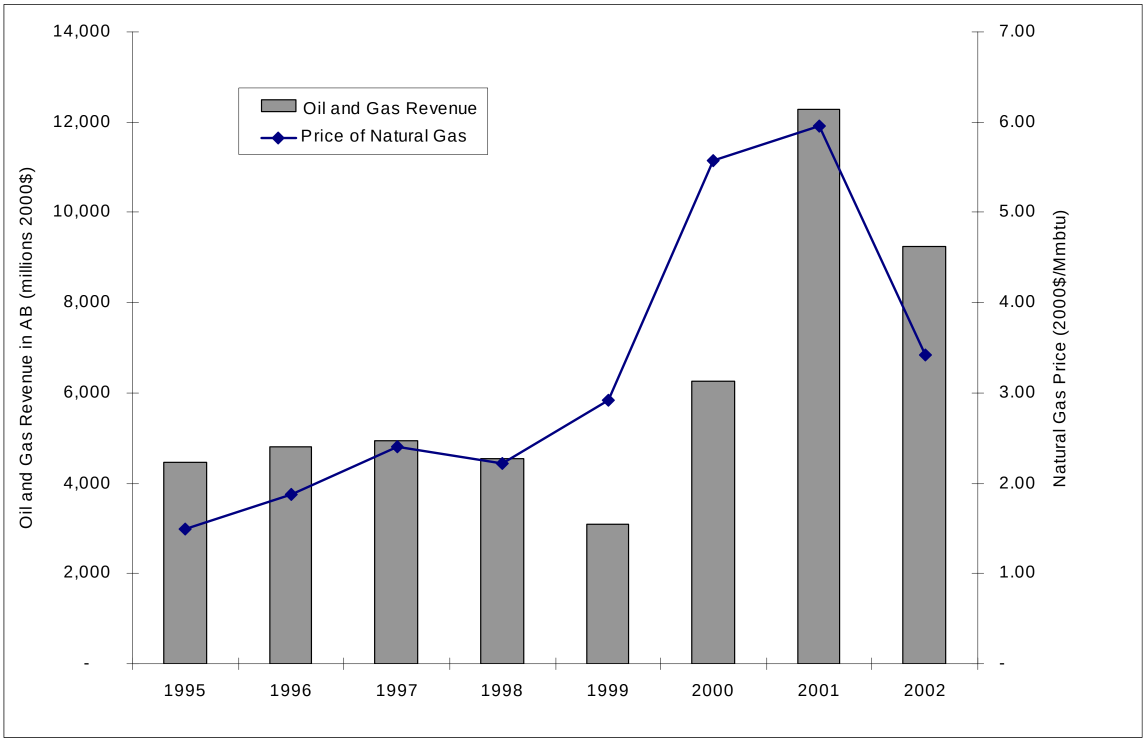

Figure 5-2 Trends in oil and gas revenues in Alberta and the price of natural gas, 2000$, 1995 to 2002

Regions that rely on oil, gas and other non-renewable resources for a substantial share of their revenue face two key problems: the revenue stream is uncertain and volatile, and the supply of the resources is exhaustible.[30] Oil and gas prices have been known to fluctuate significantly and unpredictably over time.[31] Several studies suggest that such prices do not have well-defined cycles, but rather fluctuate inconsistently and unpredictably. Research at the International Monetary Fund (IMF) found that one-third of the time the oil market faces a monthly price change greater than 8 percent. In addition, the IMF concluded, "There is also little evidence of a consistent ‘pattern’ to oil price cycles, since the probability of an end to an oil price slump or boom appears to be independent of the time already spent in the slump or boom."[32] In Canada, for the most part, pressures outside domestic markets determine the prices of natural gas and oil. Markets in the United States determine natural gas prices in Canada, and the oil prices that Canadians experience are set in international markets.[33] Regions whose economies lack

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30 Davis, Jeffrey, Rolando Ossowski, James Daniel and Steven Barnett. *Stabilization and Savings Funds for Nonrenewable Resources: Experience and Fiscal Policy Implications*. Washington, DC: International Monetary Fund, 2001.

31 Bjerkholt, Olav. “Fiscal Rule Suggestions for Economies with Non-renewable Resources.” Paper for IMF/World Bank Conference on Rules-Based Fiscal Policy in Emerging Market Economies, Oaxaca, Mexico, 2002.

32 Davis, Jeffrey, Rolando Ossowski, James Daniel and Steven Barnett. *Stabilization and Savings Funds for Nonrenewable Resources: Experience and Fiscal Policy Implications*. Washington, DC: International Monetary Fund, 2001.

33 Pipeline capacity constraints can also play a role in determining oil and gas prices in Canada by partially disconnecting Canada from these international markets.

diversity and rely on resource revenues for a large share of total revenues are particularly vulnerable to unpredictable commodity prices. Across Canada, the three western provinces of Alberta, Saskatchewan and British Columbia have ranked highest in measures of instability, from which we can infer a low degree of effective diversification.[34]

In light of these factors, policy makers must decide how to adjust government fiscal policy (spending in particular) to cushion the domestic economy from the sharp and unpredictable variations in oil and gas prices (which are beyond the control of domestic policy makers) and associated revenues. Policy makers must also consider how much oil and gas income to spend on the present generation and how much to save for future generations.[35] These challenges are compounded by the fact that oil and gas production causes negative environmental impacts. Several jurisdictions have established non-renewable permanent funds (NPFs) to address these and other challenges.

The Need for NPFs

Numerous countries have created NPFs to pool financial assets related to the development of non-renewable resources. As is described below, there are numerous justifications for the establishment of NPFs. The objectives of a specific fund will determine its design details.

Providing for Future Generations

NPFs can be used to address concerns about intergenerational equity[36], or to provide for future generations. Resources depleted by current generations will not be available for the benefit of future generations. To maintain fairness across generations, therefore, as non-renewable resources are depleted some other form of wealth must replace the value of those resources. NPFs can be used to create a store of wealth for future generations, so they benefit from part of the revenue arising from the depletion of resources today.[37] Total regional wealth can be seen as the sum of the net financial capital of the NPF and natural resource capital (the value of oil and gas resources in the ground). Governments can ensure that the total value of that wealth remains consistent over time.

Protection from Boom and Bust Cycles

As oil and gas prices increase or decrease, the amount of new exploration and development that takes place in a region can also vary significantly. During times of high oil and gas prices, resource exploration and development activity rapidly accelerates. On the other hand, during times of low prices, resource exploration and development activity is deferred. Oil and gas exploration and development are associated with increased employment in the resource sector, which often draws people away from the service sector in northern Canada. Thus, communities in the vicinity of oil and gas deposits can realize unpredictable boom and bust economic cycles as prices increase and decrease and jobs shift between sectors and regions. These cycles can

[34] Chambers, Edward. “Comments on Diversification” in L. S. Wilson, ed. *Alberta's Volatile Government Revenues*. Edmonton, Alberta: Institute for Public Economics, 2002.

[35] Fasano, Ugo. *Review of the Experience with Oil Stabilization and Savings Funds in Selected Countries*. Washington, DC: International Monetary Fund, 2000.

[36] Intergenerational equity dictates that future generations are entitled to the same level of wealth as current generations.

[37] Davis, Jeffrey, Rolando Ossowski, James Daniel and Steven Barnett. *Stabilization and Savings Funds for Nonrenewable Resources: Experience and Fiscal Policy Implications*. Washington, DC: International Monetary Fund, 2001.

be difficult to adjust to in a short amount of time and may result in periodic and unpredictable times of high unemployment and slow economic growth. In addition, when a large share of total government revenue comes from oil and gas resources, determining appropriate spending levels may be particularly challenging.[38] NPFs can protect communities from boom and bust economic cycles by providing a mechanism to stabilize government revenues. When resource prices are high, the funds receive revenues. These revenues can be transferred to the budget when resource prices are low.

Providing a Stable and Long-term Revenue Stream

NPFs provide a stable and long-term revenue stream that can be used when revenues from oil and gas resources decline as resource reserves are depleted and royalties and other revenues drop.[39] It is easier for governments to adjust to declining levels of resource earnings in the long run if funds have been accumulated in NPFs while the resources are being developed. In addition, the recent trend in several Canadian jurisdictions has been to reduce capital and income taxes.[40] Both of these taxes are a stable source of revenues (especially compared to oil and gas revenues, which fluctuate unpredictably with oil and gas prices). As they are reduced, it becomes increasingly important for governments to compensate for this with another form of stable revenue. NPFs can fulfill this need.

Transitioning from Non-renewable to Renewable Energy Sources

Non-renewable resources, such as oil and gas, are by definition exhaustible and, hence, unsustainable. As oil and gas production takes place, reserves are depleted. Even in the face of significant reserves, governments should plan a smooth transition away from oil and gas resources and towards renewable resources. By establishing NPFs, governments can create a store of funds that can be used to facilitate a transition from reliance on non-renewable resources to renewable resources over time. In this way, even though they are not sustainable themselves, non-renewable resources can be used to bridge the gap until renewable resources are developed, and to provide a stream of revenue that can be used, in part, to facilitate the shift to renewable resources.

NPFs in Action

Governments in Alaska and Norway have recognized the value and importance of NPFs and have made them a major component of resource management policy governing oil and gas production in their respective regions. These two jurisdictions have established NPFs to protect against boom and bust economic cycles, provide economic stability, accumulate significant wealth and give a long-term revenue stream to their regions. While Alberta has created a savings fund of sorts, the Alberta Heritage Fund (which will be described in more detail below), the current operation and objectives of this fund are substantially different from NPFs in Alaska and Norway. Although it will not be described in detail, in 2000/2001 the Government of Saskatchewan created the Fiscal Stabilization Fund, which at that time had a balance of $775 million. Since then, the provincial government has drawn from the fund on a regular basis. The

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[38] Engel, Eduardo and Rodrigo Valdes. *Optimal Fiscal Strategy for Oil Exporting Countries*. Washington, DC: International Monetary Fund, 2000.

[39] Davis, Jeffrey, Rolando Ossowski, James Daniel and Steven Barnett. *Stabilization and Savings Funds for Nonrenewable Resources: Experience and Fiscal Policy Implications*. Washington, DC: International Monetary Fund, 2001.

[40] For example, British Columbia and Saskatchewan recently reduced capital taxes. Alberta has reduced income taxes.

government is expected to reduce the fund to zero in 2005/2006, when the balance of $143.5 million will be withdrawn.[41] While the establishment of the Fiscal Stabilization Fund in Saskatchewan is consistent with some of the reasoning behind NPFs, the lack of a long-term vision and plan for the fund means that it falls short of the potential for NPFs over time.

Alberta Heritage Fund

The Alberta Heritage Fund differs from the Alaska Permanent Fund and the Norway Petroleum Fund both in its objectives and operation. The Alberta Heritage Fund was created in 1976 by then premier of Alberta, Peter Lougheed, at a time when Alberta oil and gas revenues were experiencing a boom.[42] The initial investment to the fund was $620 million. The start-up money also included a $1.5 billion transfer of cash and financial assets from Alberta's General Revenue Fund.[43] From 1976 to 1983, 30 percent of provincial resource revenues were transferred to the fund each year. In 1983, the resource revenue transfer was reduced to 15 percent. In 1987, it was stopped completely.

A fundamental objective of the Alberta Heritage Fund at the time of its creation was to provide economic stability by setting aside government revenues from natural resource royalties.[44] When it was established, Peter Lougheed outlined four objectives for the fund. First, the fund was to function as a savings account that would offset declining resource revenue in the future. Second, the fund was to provide additional leveraging opportunities for the government, thus reducing the government's future debt load. Third, the fund was to improve quality of life for Albertans. Finally, the fund was to facilitate stability in the economy by providing money to diversify economic activity in the province.[45] The government first drew on the Alberta Heritage Fund's investment income in 1982.[46] Between 1982 and 1995, income from the fund was transferred to the General Revenue Fund to help pay for ongoing government programs and services. Projects such as irrigation works, parks, hospitals and research projects were supported with income from the Alberta Heritage Fund. During the same period of time, no inflation proofing took place. The result was that the value of the fund began to decline.

Transfers to the General Revenue Fund stopped in 1995, and the fund has been valued at approximately $12 billion ever since. The objectives of the Alberta Heritage Fund have vacillated as circumstances changed: "Objectives have been modified or abandoned, directly or indirectly, by the Alberta government during the life of the fund."[47] In 1997, the Alberta Heritage Fund was restructured.[48] It was divided into the Transition Portfolio to meet immediate fiscal

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[41] See sask.cbc.ca/features/SASKbudget2004/deficit.html.
[42] Gillett, Sandy. *Oil and Gas Legacy Funding in Norway, Alaska, Alberta and British Columbia*. Vancouver, British Columbia. 2002.
[43] Op. cit.
[44] 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.
[45] Op. cit.
[46] Gillett, Sandy. *Oil and Gas Legacy Funding in Norway, Alaska, Alberta and British Columbia*. Vancouver, British Columbia. 2002.
[47] 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.
[48] Gillett, Sandy. *Oil and Gas Legacy Funding in Norway, Alaska, Alberta and British Columbia*. Vancouver, British Columbia. 2002.

needs, and the Endowment Portfolio to maximize long-term investments.[49] As part of this restructuring, the fund was protected against devaluation due to inflation. A portion of income earned by the fund is now transferred back into the Endowment Portfolio to offset losses in capital value due to inflation. All other income is transferred into the General Revenue Fund.

Transferring oil and gas revenues to general revenues means that spending patterns will fluctuate depending on the amount of revenue received, which depends on international oil and gas prices beyond the control of the Alberta and Canadian governments. This can lead to inconsistency in fiscal policy and unstable boom and bust economic cycles. Research suggests that rather than have spending patterns follow non-renewable resource revenue patterns, it is better to maintain consistency in spending programs and policies, even in the face of significant revenues.[50]

Alaska Permanent Fund

The Alaska Permanent Fund was created in 1976, the same year as the Alberta Heritage Fund, in response to significant resource revenues associated with a major oil discovery at Prudhoe Bay. The fund was established to provide long-term stability to fiscal policy, to save resource revenues for future generations as resources decline, and to return a share of resource revenues from oil and gas developments to the people of Alaska. A constitutional obligation requires that at least 25 percent of all mineral lease rentals, royalties, royalty sale proceeds, federal mineral revenue sharing payments, and bonuses received by the State of Alaska be placed into the fund.[51] Income from the fund is used to finance dividend cheques to the citizens of Alaska, to ensure that the value of the fund keeps pace with inflation, and to increase the principal amount of the fund.[52] In 2002, every Alaskan citizen received $1,540.76 as a dividend from the fund. The largest amount ever distributed was $1,963.86 in 2000.[53]

Since its creation, the value of the Alaska Permanent Fund has grown to US$27 billion, and the fund has earned more than US$20 billion in net income. Its return over the last 15 years has been 12.2 percent.[54] The Alaska Permanent Fund's investment strategies have ensured its continuous growth, both in terms of its asset base and its ability to earn revenues.[55] The fund currently accounts for more than 50 percent of central government revenue in Alaska.[56] There is a strong citizens' interest in the fund's operation and investment activities. The Alaska

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[49] Gillett, Sandy. *Oil and Gas Legacy Funding in Norway, Alaska, Alberta and British Columbia*. Vancouver, British Columbia. 2002.
[50] Bjerkholt, Olav. *Fiscal Rule Suggestions for Economies with Non-renewable Resources*. Paper for IMF/World Bank Conference on Rules-Based Fiscal Policy in Emerging Market Economies, Oaxaca, Mexico, 2002.
[51] Fasano, Ugo. *Review of the Experience with Oil Stabilization and Savings Funds in Selected Countries*. Washington, DC: International Monetary Fund, 2000.
[52] Op. cit.
[53] Gillett, Sandy. *Oil and Gas Legacy Funding in Norway, Alaska, Alberta and British Columbia*. Vancouver, British Columbia. 2002.
[54] 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.
[55] Op. cit.
[56] Fasano, Ugo. *Review of the Experience with Oil Stabilization and Savings Funds in Selected Countries*. Washington, DC: International Monetary Fund, 2000.

Permanent Fund can only undergo fundamental changes through constitutional amendment.[57] In 1999, a citizens' vote was solicited to consider the possibility of using some of the fund's principal to balance the state budget. With a nearly 95 percent voter turnout, more than 70 percent voted "no" to spending Alaska Permanent Fund earnings.[58]

Norway Petroleum Fund

The Norway Petroleum Fund was created in 1990, and the first transfer to the fund took place in 1996.[59] The fund's objectives relate to both economic stability and long-term savings. As resource revenues increase, due, for example, to increasing commodity prices, funds are accumulated in the Norway Petroleum Fund rather than in general revenues. This allows the government to dampen inflationary pressures and contain the potential appreciation of the exchange rate. During declines in commodity prices, previously accumulated financial assets can be accessed to provide stable and consistent government spending.[60] Reserves can be used either in the short run, as a financial buffer against revenue declines to avoid a budget deficit, or in the long run, as oil production declines and social expenditure increases, thereby promoting intergenerational equity. The fund also contributes to increasing transparency in the use of oil revenue.[61]

The Norway Petroleum Fund receives income from two sources. The first source is the government's net cash flow from petroleum activities. The second source is the return on the fund's capital.[62] All budget surpluses are also placed in the Norway Petroleum Fund. Expenditures from the fund are split among earning more income, funding social programs, and financing reductions in income taxes. The fund currently accounts for about 20 percent of central government revenue in Norway.[63] Projections predict that the fund will grow to 93 percent of GDP by 2010.

When the Norway Petroleum Fund was created, asset management was conservative and restricted to low-risk investments.[64] Today, all fund assets are invested in foreign financial assets, including fixed-income instruments and equity in mature markets. The objective of this investment strategy is to help dampen the appreciation of the real exchange rate in the face of rising oil export revenues, thereby protecting the competitiveness of the non-oil sector and supporting the fund's stabilization objectives.[65] In 2001, the Environment Fund was created. A

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[57] 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.
[58] Op. cit.
[59] 1996 was the first year the Government of Norway realized a fiscal surplus since 1990.
[60] Fasano, Ugo. *Review of the Experience with Oil Stabilization and Savings Funds in Selected Countries*. Washington, DC: International Monetary Fund, 2000.
[61] Op. cit.
[62] Gillett, Sandy. *Oil and Gas Legacy Funding in Norway, Alaska, Alberta and British Columbia*. Vancouver, British Columbia. 2002.
[63] Fasano, Ugo. *Review of the Experience with Oil Stabilization and Savings Funds in Selected Countries*. Washington, DC: International Monetary Fund, 2000.
[64] Davis, Jeffrey, Rolando Ossowski, James Daniel and Steven Barnett. *Stabilization and Savings Funds for Nonrenewable Resources: Experience and Fiscal Policy Implications*. Washington, DC: International Monetary Fund, 2001.
[65] Fasano, Ugo. *Review of the Experience with Oil Stabilization and Savings Funds in Selected Countries*. Washington, DC: International Monetary Fund, 2000.

portion of the Norway Petroleum Fund money is placed in the Environment Fund, which invests only in companies that satisfy certain environmental criteria. The Norway Petroleum Fund is considered a successful policy mechanism. It has contributed to a consistent budget surplus in Norway – even in 1998, when oil prices dropped significantly.[66]

Fund Comparison

Table 5-1 shows the value of the NPFs in each of Alberta, Alaska and Norway over the study period. It's clear that the value of the Alaska Permanent Fund and the Norway Petroleum Fund far exceed the value of the Alberta Heritage Fund.

Table 5-1 NPFs in Alberta, Alaska and Norway, 1995 to 2002 (million 2000$)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
Alberta	13,753	13,677	12,956	13,054	12,524	12,419	12,123	11,852
Alaska	22,728	26,539	30,148	35,065	39,137	38,354	36,159	35,724
Norway	NA[67]	11,103	27,103	39,827	45,519	80,415	110,650	101,073

Also noteworthy is the change in value of the various funds. While the value of Alberta's fund declined between 1995 and 2002, that of both the Norwegian fund and the Alaskan fund increased – significantly, in the case of the Norway Petroleum Fund. In 1996, when the first deposit was made into Norway's NPF, the value of this fund was less than the value of the Alberta Heritage Fund. Yet, in 2002, the value of Norway's fund was almost ten times greater than the value of Alberta's fund.

Key differences among the funds include the following:

- Compared to the funds in Norway and Alaska, it is much easier for the Alberta government to change the Alberta Heritage Fund's investment policies or even the structure of the fund itself.[68]
- Governments in Alaska and Norway still contribute to their funds on an annual basis, while oil and gas revenues are not currently transferred to the Alberta Heritage Fund.
- Until recently, the Alberta Heritage Fund was not protected from inflation. The other funds are. Due to population increases in Alberta and the stagnant nature of the fund, on a per-capita basis it is worth much less now than it was worth in 1995.
- The focus of the funds in Norway and Alaska is at least partly on growing the total value of the fund over time.

The benefits of NPFs are substantial. These funds provide insurance against declining revenues from resource production as non-renewable resources are depleted over time. They also ensure that future generations will benefit from the production of resources today. They can be used to help mitigate boom and bust cycles, help provide economic diversification to rural communities, and facilitate a transition to renewable resources in the future. In addition, money accumulated in NPFs can help to lessen future risk and liability associated with environmental impacts. This will become increasingly important as oil and gas developments increase and evolve, expanding

[66] Fasano, Ugo. *Review of the Experience with Oil Stabilization and Savings Funds in Selected Countries*. Washington, DC: International Monetary Fund, 2000.
[67] The first deposit into the Norway Petroleum Fund took place in 1996, the first year that Norway realized a budget surplus since the fund was created in 1990.
[68] 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.

associated environmental impacts. The next chapter explores these environmental impacts in more detail.

6 Oil and Gas Environmental Impacts

Environmental impacts associated with oil and gas developments in Canada are numerous. These impacts include:

- fragmentation of wildlife habitat due to cutting seismic lines and clearing roads, wellpads and pipeline right of ways;
- emissions of greenhouse gases associated with pipeline compressors, gas plants and oil batteries;
- sedimentation of creeks and streams from road run-off;
- spills and leaks of oil and gas, including the health and safety risk from sour gas[69]; and,
- issues related to oilfield waste disposal.

Oil and gas developments also result in the release of acidifying emissions. Deposition of these compounds into terrestrial and aquatic ecosystems can result in acidification of the recipient ecosystems. Levels of acid deposition that exceed the buffering capacity of the receiving ecosystem can cause changes in the chemical properties of the soil or water bodies. These chemical changes may modify chemical and nutrient cycling within the ecosystem, affect the biological composition of the ecosystem, and affect the overall ability of the ecosystem to function. Nitrogen oxides (NOx) react with volatile organic carbon compounds in the presence of sunlight to form ground-level ozone. Sulphur dioxide (SO_2) and NOx compounds also contribute to the secondary formation of fine particulate matter in the atmosphere.

In the sections that follow, we explore trends in environmental impacts associated with oil and gas developments. For British Columbia, Saskatchewan and Alberta, we present data for three categories of impacts: land disturbance, acidifying emissions and greenhouse gas emissions.[70] To show land disturbance impacts, as described in the methodology chapter, we employ a footprint analysis. This technique converts activities that alter land to area of land disturbed. The rationale behind the footprint theory is that it shows how much land is altered and therefore not available for alternative uses, such as habitat for wildlife, forestry, recreation, etc. In the following sections, we do not attempt to describe the implications of the amount of land disturbed. Rather, we simply present estimates of area altered. For the Northwest Territories and Yukon Territory, where oil and gas production is still relatively minor, significant environmental impacts have yet to be realized. However, as pressure to develop resources in northern Canada grows and oil and gas production increases, Yukon Territory and the Northwest Territories will experience environmental impacts from oil and gas developments. We discuss the key environmental issues related to oil and gas developments in the territories below.

British Columbia

Table 6-1 shows indicators of environmental impacts associated with oil and gas developments in British Columbia. For every indicator, the trend has been towards increasing impact. The significant increase in oil and gas production in British Columbia has therefore not been without significant environmental costs. The number of wells drilled in 2002 exceeded the number

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[69] Sour gas is natural gas containing hydrogen sulphide in measurable concentrations. It is a naturally occurring, highly toxic gas.

[70] Emissions data for 1995 to 2002, inclusive, are from Clearstone Engineering. *Emissions Inventories for GHG and CAC*, Volumes 1 and 2. Produced for the Canadian Association of Petroleum Producers, 2004.

drilled in 1995. The footprint associated with wellpads in British Columbia increased from 8,902 hectares in 1995 to 13,508 hectares in 2002. Pipeline construction varied from year to year, peaking in 1998, but the cumulative footprint associated with those pipelines increased every year. Emissions of nitrogen oxides, sulphur dioxide and greenhouse gases increased by 78 percent, 20 percent and 47 percent, respectively.

Table 6-1 Indicators of environmental impacts, British Columbia, 1995 to 2002

WELLS DRILLED	1995	1996	1997	1998	1999	2000	2001	2002
Annual Wells Drilled[71]	438	461	583	652	620	770	875	645
Cumulative Wellpad Footprint (ha)	8,902	9,363	9,946	10,598	11,218	11,988	12,863	13,508
Annual Pipelines Constructed (km)[72]	809	954	1,153	1,953	1,390	1,724	1,499	1,405
Cumulative Pipelines Constructed (km)	3,714	4,668	5,821	7,774	9,164	10,888	12,387	13,792
Cumulative Pipelines Footprint (ha)	5,571	7,002	8,731	11,661	13,746	16,332	18,580	20,688
Annual Nitrogen Oxides (t)	25,806	27,443	29,225	34,896	36,584	37,860	42,582	45,903
Annual Sulphur Dioxide (t)	31,523	33,880	54,210	46,143	32,733	31,318	35,224	37,972
Annual Greenhouse Gas Emissions (kt)	5,905	6,313	6,518	7,041	7,093	7,183	8,079	8,709

Alberta

The trend in environmental indicators in Alberta is similar to the trend in British Columbia. More wells were drilled in 2002 than in 1995, and emissions of nitrogen oxides and greenhouse gases increased. As in British Columbia, the length of pipelines constructed varied from year to year. In 1995, a total of 16,787 kilometres of pipelines were constructed. In 2002, that figure was 10,833 kilometres – less than half the length constructed in the peak year of 1998. The estimated cumulative pipelines footprint in Table 6-2, however, demonstrates that the total amount of land disturbed by pipelines in Alberta has increased significantly, from 311,311 hectares in 1995 to 478,681 hectares in 2002. The figures below for emissions do not include emissions from oil sands developments.

[71] *Opening Up Oil and Gas Opportunities in British Columbia: Statistics and Resource Potential, 1992 to 2002.*
[72] *British Columbia Oil and Gas Commission, http://www.ogc.gov.bc.ca/sitemap.asp*

Table 6-2 Indicators of environmental impacts, Alberta, 1995 to 2002

WELLS DRILLED	1995	1996	1997	1998	1999	2000	2001	2002
Annual Wells Drilled[73]	8,442	10,203	12,249	7,628	9,049	12,719	13,628	12,989
Cumulative Wellpad Footprint (ha)	93,042	103,245	115,494	123,122	132,171	144,890	158,518	171,507
Annual Pipelines Constructed (km)[74]	16,787	12,921	16,174	22,411	14,309	16,152	18,780	10,833
Cumulative Pipelines Constructed (km)	207,541	220,462	236,636	259,047	273,356	289,508	308,288	319,121
Cumulative Pipelines Footprint (ha)	311,311	330,693	354,954	388,570	410,034	434,262	462,432	478,681
Annual Nitrogen Oxides (t)	243,115	252,861	286,879	292,120	304,929	310,317	300,931	294,080
Annual Sulphur Dioxide (t)	271,043	253,742	255,140	222,798	195,800	226,122	219,283	214,290
Annual Greenhouse Gas Emissions (kt)	52,548	55,623	58,603	59,804	60,062	61,366	59,510	58,155

Saskatchewan

The environmental trends in Saskatchewan mirror those in British Columbia and Alberta; all indicators showed an increasing trend, with the exception of the annual kilometres of pipelines constructed. The annual number of wells drilled increased by 63 percent, emissions of nitrogen oxides increased by 8 percent, emissions of sulphur dioxide increased by 37 percent, and emissions of greenhouse gases increased by 58 percent. As in the other two provinces, the length of pipelines constructed varied from year to year, but peaked in 1998. Inevitably, the cumulative impact of all activities increased each year.

[73] *EUB Statistical Series 57: Field Surveillance Provincial Summaries, 1999/2000 and 2002*
[74] *Op. cit.*

Table 6-3 Indicators of environmental impacts, Saskatchewan, 1995 to 2002

WELLS DRILLED	1995	1996	1997	1998	1999	2000	2001	2002
Annual Wells Drilled[75]	2,092	2,864	3,832	1,677	2,473	3,700	3,509	3,401
Cumulative Wellpad Footprint (ha)	52,649	55,513	59,345	61,022	63,495	67,195	70,704	74,105
Annual Pipelines Constructed (km)[76]	296	499	626	887	154	133	461	232
Cumulative Pipelines Constructed (km)	18,133	18,632	19,258	20,145	20,299	20,432	20,893	21,125
Cumulative Pipelines Footprint (ha)	27,199	27,948	28,887	30,217	30,448	30,648	31,339	31,687
Annual Nitrogen Oxides (t)	13,423	12,494	13,353	13,314	13,584	14,467	14,731	14,536
Annual Sulphur Dioxide (t)	5,281	7,202	7,932	8,962	7,177	7,214	7,346	7,249
Annual Greenhouse Gas Emissions (kt)	9,857	10,648	12,746	12,759	12,859	15,161	15,777	15,568

Yukon Territory

Compared to the other regions covered in this analysis, oil and gas production in Yukon Territory is currently minor. As a result, the environmental impacts associated with oil and gas exploration and production have, until now, been relatively small. However, Yukon Territory is particularly vulnerable to long-term damage from oil and gas development due to the sensitivity of arctic soil to disturbance and the slow-growing nature of arctic vegetation. Indeed, evidence of seismic and exploration drilling activity conducted from the early 1970s through to the mid-1980s in the northern part of the territory are still visible today. If full-scale oil and gas development were to occur in Yukon Territory, an area of relatively pristine wilderness, it would have a significant impact. Oil and gas exploration and production require extensive clearing of land and construction of infrastructure. 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. Numerous cutlines, right of ways and roads in concentrated areas are known to result in negative impacts on wildlife and wildlife movement. In addition, there are potential impacts from air pollution and from accidental spills and leaks. Yukon Territory is at risk of experiencing all of these impacts if oil and gas production is permitted to proceed unchecked.

Northwest Territories

As the United Nations Environment Programme pointed out in a recent news release, "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

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[75] *EUB Statistical Series 57: Field Surveillance Provincial Summaries, 1999/2000 and 2002*
[76] Personal communication, Saskatchewan Industry and Resources

market by pipeline. If approved and constructed, this Mackenzie Valley Pipeline would be the largest industrial development to occur in the North.

The Northwest Territories is already experiencing impacts associated with existing oil and gas development taking place 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.[77] The consultants estimated the cumulative effects of industrial development on the Fort Liard region of the NWT using the United 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 6-4 shows the results of the study for 2001.

Table 6-4 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

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,[78] the impacts in this area are indicative of what could occur in other regions should development patterns mirror those of the Fort Liard area.

Environmental Impacts in the Context of Economic Rent

The graph below puts environmental impacts, such as those described above, into the context of economic rent capture. To the extent that oil and gas companies are required to remediate environmental damage, post bonds for site reclamation, incur costs related to site abandonment and reclamation or purchase permits related to air emissions, such environmental costs become part of operating costs in the figure below. However, the reality in Canada is that only a portion of the environmental costs associated with oil and gas production are currently covered by permit and reclamation programs. Instead, the majority of the environmental costs, such as those associated with the impacts described earlier in this chapter, are passed on to the public. These take the form of degraded environmental conditions, including acid rain, climate change and loss of wildlife due to habitat fragmentation. These costs are shown as the red area in the graph below.

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

[78] 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.

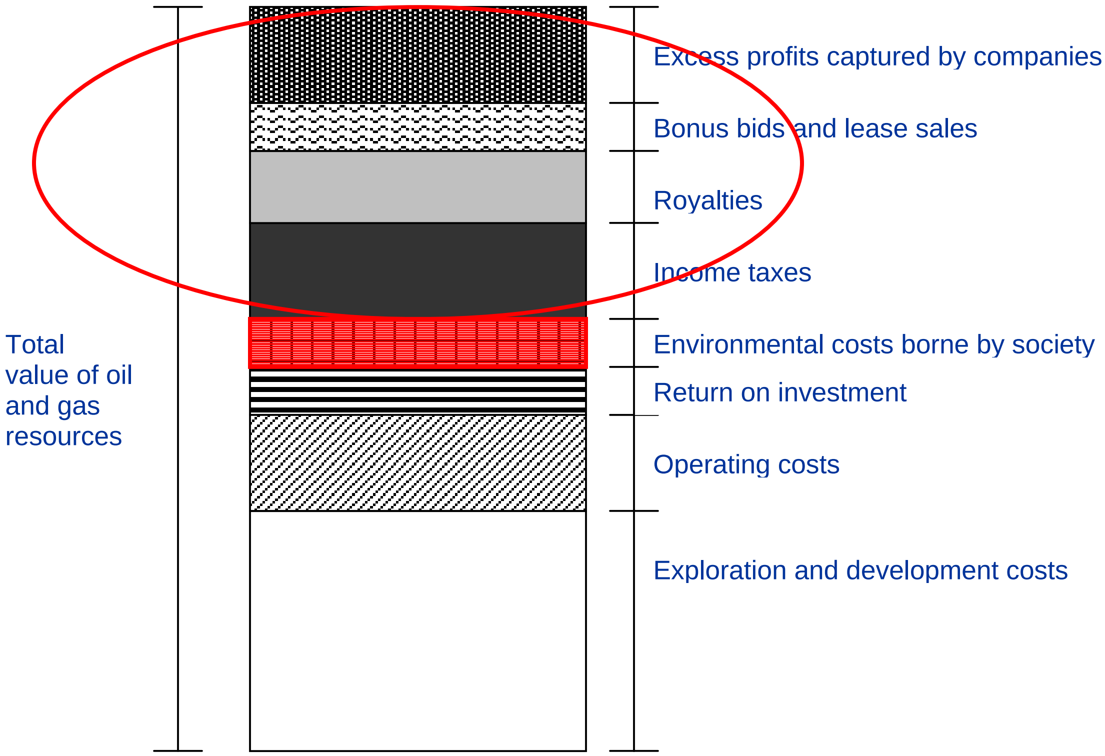

Figure 6-1 Environmental costs in the context of economic rent capture

In the context of economic rent, two key concepts related to environmental impacts are worth highlighting. First, to the extent that the government of a particular region is not capturing all of the rent that is available in that region, it is allowing companies to capture residual rent in the form of higher than normal profits. In doing so, governments are providing an implicit subsidy to oil and gas companies; they are obtaining lower royalties and taxes than can be justified based on the amount of economic rent available in a region. There are numerous reasons to avoid such a subsidy. For example, the subsidy could lead to an increase in oil and gas developments. The increase in oil and gas developments could lead to increased environmental damage. The subsidy could also perpetuate investment in non-renewable resources at the expense of investments in renewable resources. Therefore, from an environmental impact point of view, it is necessary for governments to ensure that an appropriate level of rent capture takes place to limit uneconomical developments and associated environmental damage.

A second, related concept is the need to internalize environmental costs. Fiscal policies provide a venue for incorporating environmental costs into the cost of doing business. Environmental taxes can be used as a proxy for the environmental costs that result from oil and gas production to the extent that they are levied on oil and gas producers. In this way, the environmental costs are transferred from society to industry. They are internalized and become part of a company's operating costs. Companies are thus provided with an incentive to reduce environmental costs, and their environmental tax burden. At the same time, the public is no longer bearing the weight of these costs. As described in Appendix G, Norway currently levies a carbon tax on oil and gas producers. This tax is in keeping with the “polluter pay” principle and provides an avenue for governments to internalize a portion of the environmental costs associated with oil and gas production.

7 Summary and Future Directions

This research project covered three key areas of investigation. For the period between 1995 and 2002, we explored trends in economic rent capture, non-renewable permanent funds, and environmental impacts associated with oil and gas developments in western and northern Canada. Below we summarize the results for each of these topics.

To discern trends in economic rent, we investigated not only the amount of revenue obtained by governments from oil and gas developments, but also trends in the value of oil and gas resources and the cost of oil and gas production. We found that relative to Alaska and Norway, Canadian governments obtain lower revenues from oil and gas developments. Table 7-1 shows the value of revenues obtained per unit of production in each of the jurisdictions over time.

Table 7-1 International comparison of revenue generation from oil and gas production, 1995 to 2002 (2000$/BOE)

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	2.6	3.7	3.7	2.7	4.1	8.6	10.1	8.1
AB	3.1	3.2	3.1	3.1	2.1	4.2	8.5	6.8
SK	4.5	4.4	4.7	3.5	2.7	5.0	6.6	5.9
YT	1.2	2.7	1.8	1.6	1.1	2.2	4.9	4.5
NWT	1.2	2.6	1.7	1.2	1.3	2.2	2.5	4.5
Alaska	13.3	10.5	12.2	10.5	8.7	13.7	13.0	10.5
Norway	7.9	12.8	14.8	6.8	6.7	19.7	26.1	18.1

To establish whether lower revenue generation in the Canadian regions was justifiable on the basis of either higher production costs or lower resource values, we examined estimates for these factors over the study period for each region. The analysis revealed that Alaska obtained higher revenues from oil and gas developments relative to Canadian regions despite having higher production costs and comparable resource values. In the case of Norway, higher revenues were the result of a combination of differences in resource values and production costs as well as policy decisions by the government. Ultimately, in both Alaska and Norway, government policy was important in allowing these international benchmarks to collect higher revenues.

To complete the analysis of differences in revenue generation, we presented estimates for the amount of economic rent available in each region and compared this with the level of revenue generation. Table 7-2 shows the outcome of this analysis. We found that, with the exception of British Columbia, oil and gas producing regions in western and northern Canada collected substantially less revenue, as a percentage of the economic rent available to them, than did the international benchmarks of Alaska and Norway. While we did not do a comprehensive analysis of the specific policy features that led to higher rent capture in Alaska and Norway, some key differences in government approaches include Norway's special tax, Alaska's production tax, differences in royalty and tax rates and the number of credit and incentive programs available, as well as Norway's partial ownership of oil and gas resources, which results in dividends paid to the government.

Table 7-2 Portion of rent captured by governments, 1995 to 2002

REGION	1995	1996	1997	1998	1999	2000	2001	2002
BC	100%	100%	100%	100%	100%	47%	100%	100%
AB	89%	100%	100%	100%	35%	31%	58%	41%
SK	50%	51%	100%	100%	58%	23%	50%	75%
YT	13%	40%	100%	100%	8%	91%	100%	100%
NWT	13%	40%	100%	100%	9%	91%	100%	100%
Alaska	100%	100%	100%	100%	100%	100%	88%	100%
Norway	64%	80%	96%	100%	100%	65%	100%	100%

Our investigation of non-renewable permanent funds (NPFs) revealed a need to establish such funds for many reasons, including providing for future generations, mitigating boom and bust economic cycles, transitioning to renewable energy sources over time, and providing a stable and long-term revenue stream to governments as resources are depleted. Despite the strong need for the establishment of NPFs in regions that develop oil and gas resources, none of the Canadian regions currently contribute to such funds. In 1976, Alberta established the Alberta Heritage Fund, and revenues from oil and gas developments were contributed to the fund for a number of years. However, the value of the fund is now stagnant, and is dwarfed by the magnitude of such funds in both Norway and Alaska. Without non-renewable permanent funds government expenditure tends to mirror revenues such that annual expenditure on core government services (health and education) becomes reliant on the volatile and unpredictable prices of oil and gas commodities.

With respect to environmental impacts, our analysis revealed a significant increase in environmental indicators associated with oil and gas developments in western and northern Canada over the study period, resulting not only in the depletion of unsustainable resources but also collateral damage to environmental capital as well. For example, between 1995 and 2002 in British Columbia, emissions of nitrogen oxides, sulphur dioxide and greenhouse gases from oil and gas developments in the province increased by 78 percent, 20 percent and 47 percent, respectively. In Alberta, oil and gas emissions of nitrogen oxides and greenhouse gases increased by 21 percent and 11 percent, respectively. Indicators of environmental impacts in Saskatchewan include increases in greenhouse gas emissions (58 percent) and an increase in the annual number of wells drilled in the province (63 percent). Pressures to increase oil and gas developments in northern Canada could lead to similar increases in environmental impacts in those regions of the country.

Based on the above analysis, we can make a number of recommendations for future policy directions related to oil and gas developments in Canada:

1. **Ensure that the citizens in western and northern Canada are receiving appropriate compensation for the development of oil and gas resources.** With the exception of British Columbia, Alaska and Norway capture a greater portion of economic rent from oil and gas developments than do western and northern Canadian regions. Canadian governments need to ensure that they are obtaining the maximum compensation for the development of oil and gas resources by altering the mix and level of royalties, taxes and tax credits in place in Canadian regions. This is necessary not only from a revenue generation perspective, but also to avoid an implicit subsidy to the oil and gas sector that might perpetuate investments in these non-renewable resources at the expense of

investments in sustainable energy options. Future policy research should consider reducing existing tax credits and investigate specific policy options, such as the special tax and the production tax in place in Norway and Alaska respectively, that would allow them to capture higher rent than Canadian jurisdictions. Canadian authorities need to investigate the applicability of such options in Canadian jurisdictions and evaluate the level of public expenditure (in the form of tax credits) on oil and gas developments in the country. Governments in Canada should monitor the capture of economic rent and inform the public of the level of compensation occurring over time.

2. **Establish non-renewable permanent funds.** Canadian jurisdictions need to quickly establish non-renewable permanent funds. These funds need to increase in value as resources are depleted and be protected against inflation, providing both savings and stability to Canadian economies. The Alberta government needs to once again dedicate funds to the Alberta Heritage Fund, which is dwarfed by non-renewable permanent funds in Alaska and Norway. Establishing such funds is particularly important in Yukon Territory and the Northwest Territories, where oil and gas developments may increase rapidly. These communities, due to their relatively smaller populations and economies, are particularly vulnerable to boom and bust economic cycles. Non-renewable permanent funds can play an essential role in providing stability in the face of volatile and unpredictable oil and gas prices – prices that, as we have described, are beyond the control of Canadian governments. Canadian leaders should look to the successful experiences of other jurisdictions, such as Norway and Alaska, to inform them on appropriate establishment and design features.

3. **Evaluate revenue generation from oil sands developments and plan for increasing production levels in the future.** Between 1995 and 2002, oil sands production increased by 74 percent, yet, over the same time period, royalty revenues from oil sands declined by 30 percent. This massive discrepancy will become an ever-larger concern as oil sands constitute an increasing portion of total oil and gas developments in Alberta. By 2010, oil sands are expected to account for more than 60 percent of total oil production in western Canada. Already, oil sands make up 30 percent of oil production in Alberta. The Government of Alberta needs to begin increasing oil sands revenues today and reverse the trend of declining royalties per unit of oil produced from oil sands in Alberta.

4. **Minimize and/or mitigate environmental impacts associated with oil and gas developments.** Evidence presented in this report demonstrates that as oil and gas developments in Canada have increased, so, too, have environmental impacts, including (but not limited to) land disturbances, acidifying emissions and greenhouse gas emissions. These impacts need to be minimized and/or mitigated if production is to take place on the scale envisioned by current governments.[79] Regulations need to be established that ensure that the best available technologies are employed in oil and gas operations in Canada, and fiscal policies need to provide incentives to oil and gas companies to exceed the standards set by the regulations.

5. **Internalize environmental costs through the use of environmental taxes.** Governments in Canada need to adopt the "polluter pay" principle and begin to implement environmental taxes and fees as a way of incorporating environmental costs

[79] For example, the B.C. government wants to double oil and gas production in the province by 2010.

and providing incentives to reduce environmental impacts. This analysis has shown that as oil and gas production increased in Canada between 1995 and 2002, so, too, have environmental impacts. We have seen significant increases in land disturbances, acidifying emissions and greenhouse gas emissions. The current fiscal regime does not account for these impacts. Instead, the majority of environmental costs associated with oil and gas production are borne by society in the form of degraded environmental conditions. Fiscal policy, and environmental taxes in particular, can play a role in curbing this trend. Environmental taxes should be used, as they are in Norway, to internalize a portion of these costs so they become part of the cost of operating oil and gas developments in Canada. The revenue from such taxes can be used in several ways including the reduction of existing taxes or additional incentives (tax credits and grants) to invest in environmentally sensitive goods and technologies.

In this report we have presented essential evidence related to three important concepts of relevance to oil and gas developments. The analysis of economic rent revealed that for most Canadian regions considered in this analysis, governments are not capturing as much rent as they could be. This means that a portion of the revenue available to governments is accruing not to citizens, but to companies in the form of excess profits. The chapter on non-renewable permanent funds described the need for such funds and the lack of initiative in this regard by current governments in western and northern Canada. Finally, the investigation of trends in environmental impacts demonstrated an increase in a number of impacts associated with oil and gas developments in British Columbia, Alberta, Saskatchewan, Yukon Territory and the Northwest Territories. In conclusion, this analysis has demonstrated the need for immediate government action to maximize the capture of economic rent, ensure long term economic stability and savings to the citizens of oil and gas producing regions and increase environmental standards and incentives to reduce environmental impacts. Table 7-3 summarizes the results and main conclusion of this analysis.

Table 7-3 Summary of analysis and findings

ISSUE	KEY FINDINGS	REASONS FOR CONCERN	POSSIBLE RESPONSES
Economic Rent	With the exception of British Columbia[80], between 1995 and 2002, regions in western and northern Canada did not capture as much economic rent from oil and gas as they could have and as did Norway and Alaska.	Revenues that should accrue to citizens instead go to companies as excess profits. Compensation to citizens is not maximized.	Reduce or remove credit and incentive programs, reform taxation and royalty regimes, consider policy options in place in Norway and Alaska.
Non-renewable Permanent Funds	Non-renewable permanent funds in Alaska and Norway are significantly higher in value than the Alberta Heritage Fund. Other oil and gas producing regions in western and northern regions in Canada do not have such funds.	Vulnerability to boom and bust economic cycles, no contingency plan for the exhaustion of resources, lack of consideration for future generations or transition to renewable energy sources.	Investigate various non-renewable permanent funds and design and implement a program in each region suited to the unique circumstances of the region.
Environmental Impacts	Oil and gas developments in western and northern Canada have lead to increased land disturbance, acidifying emissions and greenhouse gas emissions.	Reduced health and habitat of wildlife, impacts on human health, long-term liability of greenhouse gas emissions.	Increase standards and incentives to reduce and minimize environmental impacts. Introduce environmental taxes to internalize externalities.

[80] Recall that since 2002, the B.C. government has implemented a number of new credit and incentive programs that are likely to result in a reduction in performance by the government on economic rent capture.

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