**Canadian Energy Research Institute**

# Economic Impacts of the Petroleum Industry in Canada

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**ECONOMIC IMPACTS OF THE PETROLEUM INDUSTRY IN CANADA**

Economic Impacts of the Petroleum Industry in Canada

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# CHAPTER 1
# INTRODUCTION

## 1.1 Background

Last year was a tumultuous year to the say the least. The first half of 2008 saw a global rise in commodity prices, most notably oil and natural gas. The Canadian dollar appreciated against its US counterpart to levels not seen in decades. While certain sectors benefited from the rise of commodity prices and concomitant rise in currency values, others faltered. The second half of the year, however, saw commodity prices plunge dramatically, amidst a global financial crisis.

In the wake of these developments, the Canadian (and American) public is expecting policy-makers to set energy and environmental policies that make appropriate tradeoffs. However, to aid the process of rational decision-making and attitude towards the petroleum industry, policy-makers and business leaders require a clear understanding of the value and contribution of the petroleum industry to the economy. Their decisions will certainly impact the level of private investment and have wide-ranging effects across various, seemingly unrelated, industries. As the petroleum industry is frequently characterized by capital-intensive projects that generate single-purpose facilities, even small changes in policies may well have large impacts on investment levels.

The recent spate of publicity surrounding environmental impacts has overshadowed the fact that Canada's petroleum industry is a significant contributor to the country's GDP. The petroleum industry has widespread economic impacts that extend far beyond the province of Alberta–-Canada's largest producer of oil and gas. Investments in new developments and expenditures in ongoing operations provide jobs that generate income-multiplier effects and economic spin-offs, benefiting the provincial and national economies.

## 1.2 Objective of the Study

It is not a secret that Canada is one of the most important energy players in the world. While centered in Alberta, other regions of the country are attracting a lot of attention and offer, in some cases, tremendous potential. Often overlooked is the fact that the petroleum industry is, at various stages, active in all of Canada's provinces and territories. Canada's most important resource, however, is the oil sands, located predominantly in Alberta, but stretches into Saskatchewan. With an estimated initial volume in-place of approximately 1.7 trillion barrels of crude bitumen, Alberta's oil sands are one of the largest hydrocarbon deposits in the world. About 10 percent (i.e., 173 billion barrels) of this volume is recoverable using today's technology. Of this recoverable bitumen reserves, 18 percent is accessible through surface mining technologies, while the remaining 82 percent requires in situ recovery technologies.

The importance of the oil sands cannot be overstated, especially as conventional oil production declines and demand for oil increases. As a result, oil sands reserves play an important role in the economic development of Alberta and Canada as a whole. What is often misunderstood is that the massive investment in the oil sands industry contributes and reverberates to the rest of Canada, through demand for labour and demand for goods and services from other provinces.[1] The same is true for other investments in the oil and natural gas industries in any province or territory, be it British Columbia, Saskatchewan or Newfoundland.

What are the impacts of a certain investment on GDP, employment, and government expenditures? More specifically, what are the economic impacts of hydrocarbon developments on key macroeconomic variables such as GDP, employment, and government revenues in a particular province or territory? Is there any way to quantify those impacts? How can we study the impacts of such investments on macroeconomic variables in other provinces? As a result of investment in the Alberta oil sands, how many new jobs will be created in Ontario or Quebec? How big is the impact of these investments on the federal budget? While straightforward, providing answers to these questions requires considerable research.

The Canadian Energy Research Institute (CERI) conducted a comprehensive assessment of the role of the petroleum industry in the provincial and national economies 25 years into the future. Utilizing an Input–Output (I/O) modeling approach, this study fills a knowledge gap that currently exists with respect to the quantification of the economic contribution of the petroleum industry at provincial, territorial, and national levels.

I/O analysis considers relations between industries in an economy and depicts how the output of one industry feeds into another industry as an input, and thereby makes one industry dependent on another. I/O modeling is a very sound approach to investigate the impacts of the investments in an industry on other industries and provinces/territories.

Using the I/O accounts published by Canada's System of National Economic Accounts (CSNEA), CERI has constructed a Canadian Multi-Regional I/O model for Canada, as an alternative to the I/O models constructed by Statistics Canada. This innovative model consists of 13 provincial and territorial Symmetric I/O Tables (SIOTs) and a trade flow matrix. Chapter 2 will discuss further the details of the methodology.

CERI's Multi-Regional I/O model reveals the details of the economic linkages in the Canadian economy. For instance, it identifies the GDP impact of one billion dollars of investment in Alberta's oil sands on the economy of Alberta, Ontario and other provinces. CERI's Multi-Regional I/O model measures the economic impacts of certain investments in a particular industry, in a particular province in Canada. Moreover, it measures the provincial, as well as the national, impacts of the total investments and production of each sectors of the economy.

CERI focuses on the petroleum industry in Canada and quantifies the economic impacts of this very important industry on Canada's overall economic condition. It identifies the direct, indirect, and induced impacts of current and future investments in Canada's petroleum industry. The primary objective of this study is to measure the incremental impacts of the development in the

[1]Inventory of Major Alberta Projects, September 2008.

oil and gas industry and the resulting impacts on the province, the other provinces and territories and total Canada. The innovative model also measures the contributions of the Canadian petroleum industry on provincial government revenues, even if the provinces are not directly involved with this industry. It is important to note that equalization payments are beyond the scope of this study.

This timely and significant study sheds light on the Canadian petroleum industry and its importance to the Canadian economy, assisting both policy-makers and business leaders to make informed decisions regarding this industry. Furthermore, it informs the public about an important industry that is often misunderstood.

### 1.3 Structure of the Report

This report has been structured as follows. As mentioned previously, Chapter 2 briefly discusses the methodology of this study. It is divided into three parts: overall modeling framework, the Multi-Regional I/O Model and CERI's previous I/O experience. Chapter 3 discusses briefly the data and key assumptions of this study. It is divided into two parts: data sources and assumptions.

The remainder of the report, from Chapters 4 through 14 discusses the economic impacts for all of Canada's ten provinces and three territories. Each of the chapters differs in structure and length depending on the various sources of oil and natural gas available. For example, Alberta is divided into six sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Alberta. The following five sections discuss and review the economic impacts of conventional oil resources, conventional gas resources, Coalbed Methane (CBM) resources, oil sands and major capital projects in the province. Each section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces and territories. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed. On the other hand, Manitoba is divided into only two sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Manitoba, while the second section discusses and reviews the economic impacts of conventional oil resources in the province.

While the petroleum industry is active in all of Canada's provinces and territories, it is at various stages of development. This makes it often difficult and impractical to complete and calculate the economic impacts of the various resources. In some cases, there was insufficient data available to perform any meaningful analysis. CERI, however, felt it important to discuss the various stages of activity in as many provinces as possible.

It is also important to mention that Chapter 14 differs in structure. The economic impacts, as well as the reserves and production, for the Yukon Territory, Northwest Territories and Nunavut are all discussed in Chapter 14, as opposed to separate chapters.

Finally, Chapter 15 presents the economic impacts for Canada. This chapter presents an overview of the current Canadian petroleum industry, and concludes with a discussion of future total economic impacts from the petroleum industry on the country.

# CHAPTER 2
# METHODOLOGY

This chapter briefly discusses the methodology of this study. It is divided into three parts: overall modeling framework, the Multi-Regional I/O Model and CERI's previous I/O experience.

The following sets out the various steps in the compilation of the Canadian Multi-Regional I/O tables, and shows how one can trace direct and indirect, and induced effects of the Canadian energy sector on the economy. This will facilitate analysis of production and demand in Canada, and allow economic studies at the provincial and national levels in Canada.

## 2.1 Overall Modeling Framework: A Generic Approach

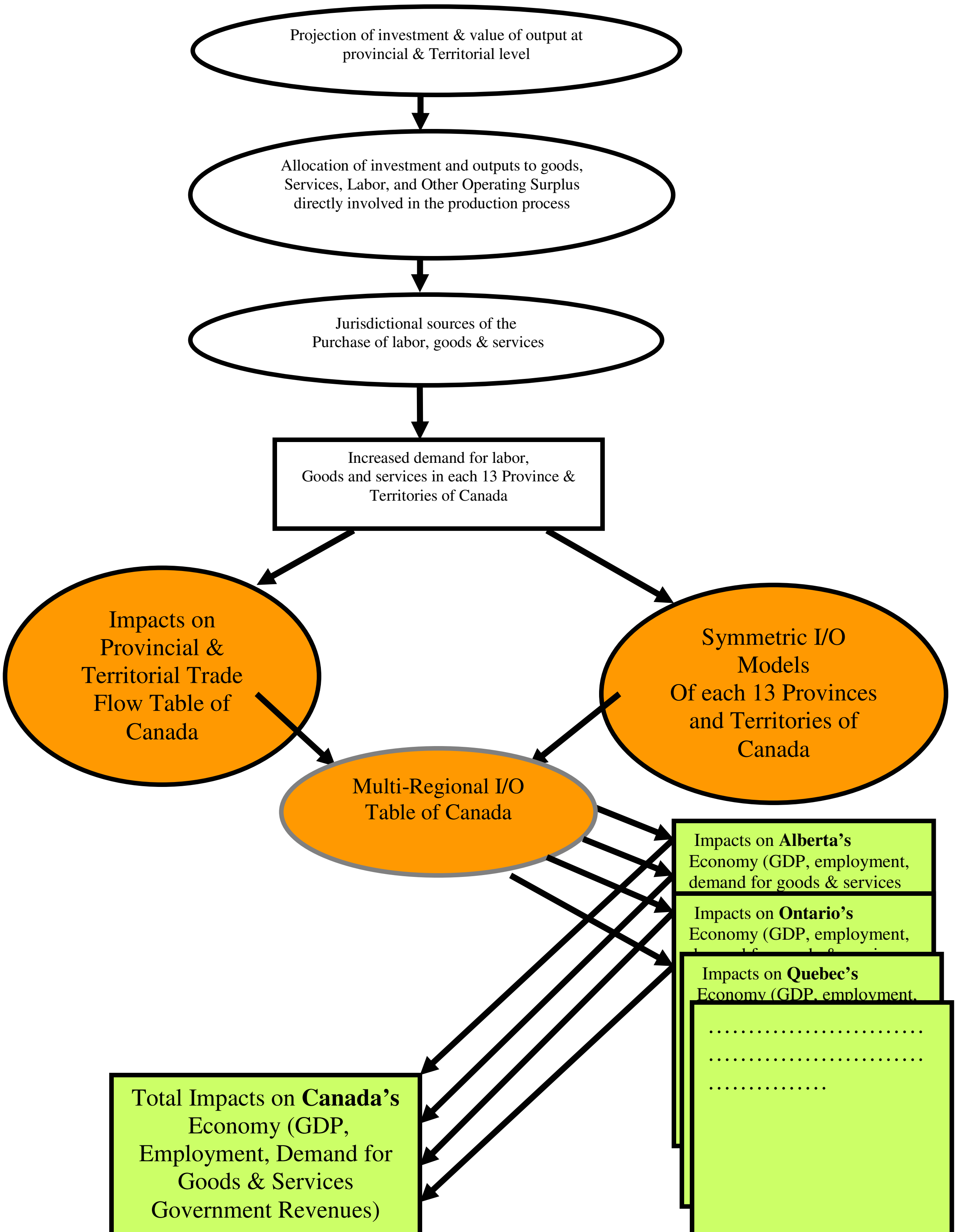
Any activity that leads to increased production capacity in an economy has two components: construction (or development) of the capacity, and operation of the capacity to generate outputs. The first component is referred to as investment, while the second is production or operation. Both activities affect the economy through purchases of goods and services, and labour. Figure 2.1 illustrates the overall approach CERI uses to assess economic impacts resulting from these activities.

The first step is to estimate and forecast the value of investment (i.e., construction or development expenditure) and production (sales). The total investment or development expenditures are then disaggregated into purchases of various goods and services directly involved in the production process (i.e., manufacturing, fuel, business services, etc.) and labour, using the expenditure shares. In a similar way, the value of total production (or output or sales) from a production activity (i.e., conventional oil production, petroleum refinery, etc.) is allocated to the purchase of goods and services, payment to labour, payment to government (i.e., royalty and taxes) and other operating surplus (profits, depreciation etc.).

The shares across goods and services and labour, combined with the forecasted values of investment and production, are then used to estimate demand for the various goods and services, and labour used in both development and production activities. These demands are met through two sources: (i) domestic production and (ii) imports. Domestic contents of the goods and services are calculated using Statistics Canada's data.

Interprovincial trade flow tables, developed by CERI, are used to derive import or export shares for each type of good and service for all 13 provinces and territories in Canada. The value of goods and services required by a particular industry and produced in each province or territory of Canada is calculated using the import and export shares. The economic impacts of the production of these goods and services in a particular province or territory of Canada are calculated in the same way as for other provinces and territories.

**Figure 2.1**
**Overall Multi-Regional I/O Modeling Approach**



## 2.2 CERI Multi-Regional I/O Model

CERI's Multi-Regional I/O model for Canada consists of 13 provincial and territorial SIOTs and a trade flow matrix. Defined in the System of National Accounts (SNA) terminology, this industry-by-industry approach is identified as the "industry technology". The Multi-Regional tables have the following advantages:

- Compatibility with economic theory;
- Recognizing institutional characteristics in each industry;
- Preserving a high degree of micro-macro link;
- The maximum use of the detailed information in Supply (make) and Use Tables (SUTs);
- Comparability with other types of statistics; and
- Transparency of compilation method, resource efficiency, support for a wider and more frequent compilation of input-output tables internationally.

CERI's Multi-Regional I/O model is constructed using CERI's 13 provincial SIOTs, which are based on national and provincial I/O tables produced by Statistics Canada.[2] More specifically, CERI uses the provincial *Make, Use, And Final Demand* tables to construct the SIOTs for every province and territory in Canada. Each province's SIOT consists of linkages between 31 industries. For that reason, the provincial SIOTs are matrices of 31×31 dimension. There are several methods of constructing the provincial industry-based SIOTs; CERI employed the fixed product sales structures method. The SIOTs are essential in building the new Multi-Regional I/O tables, and conducting I/O analysis.

The provincial (or interprovincial) trade flow table is developed by CERI. Whereas the provincial SIOTs are industry-by-industry elements, the provincial trade flow tables are industry/province elements. Statistics Canada also publishes the provincial trade flow table, but at a small aggregation level. This table presents the import and export flows among all provinces and territories in Canada, depicting the export of every industry to other provinces and territories in rows and the import of every industry from other provinces and territories in columns. Given there are 13 provinces and territories and each provincial SIOT consists of 31 industries, the provincial trade flow table is a matrix of 403×403 dimension.

The Statistics Canada I/O structure, as mentioned above, consists of three tables (or matrices): (i) "Make" or "Output" matrix, (ii) "Use" or "Input" matrix, and (iii) "Final Demand" matrix. The

[2] Statistics Canada, "The Input-Output Structure of the Canadian Economy, 2003-2004," *Catalogue No. 15-201-X*, February 2008.

*Make* matrix presents production of commodities (row) by various industries (column). The *Use* matrix presents consumption or use of commodities (row) by various industries (column). The *Final Demand* matrix presents consumption or use of commodities (row) by various final demand sectors (column), such as household, government, investment, trade and inventory. The CERI Multi-Regional I/O model database combines these three matrices, data from national and provincial accounts, and the provincial trade flow table to form national and provincial social accounting matrices.

A detailed breakdown for the oil and gas sector is not available in the Statistics Canada I/O tables, a key limitation of these tables. Statistics Canada issues the provincial table with 25 sectors. All energy commodities (i.e., coal, crude oil, natural gas) aggregated as a single 'mineral fuel', and all energy industries (i.e., coal production, coal mining, and gas production) are embedded into a single 'Mining and Oil & Gas Extraction' industry. CERI addresses this issue through greater disaggregation of the data, using a heroic[3] approach. A key feature of the CERI Multi-Regional I/O model is that the mineral fuel commodities in the Statistics Canada I/O tables are split into coal, natural gas and crude oil, which include crude bitumen and SCO from the oil sands industry. In particular, the "Mining and Oil & Gas Extraction industry' category is broken down into the following: Coal Mining, Conventional Oil, Natural Gas and NGL, Oil Sands Production and, finally, Other Mining (i.e., metal and non-metal mining except coal and bitumen mining).

Services incidental to mining are also allocated to these individual energy sectors and the other mining sector. A wide range of data including production, consumption, energy commodity prices, sectoral GDP and gross outputs (or total sales value) are required to segment the aggregated energy commodities (i.e., mineral fuels) and industries (i.e., mining, oil & gas industry, and utility industry). These data are collected from various sources such as Statistics Canada, the Canadian Association of Petroleum Producers (CAPP), the Alberta Energy and Utilities Board (AEUB) and Natural Resources Canada. The Statistics Canada I/O tables present a very detailed disaggregation of some sectors such as service sectors. As this sector is much less energy intensive, such a detailed disaggregation is not necessary for energy and environmental policy analysis. Consequently, CERI's Multi-Regional I/O model represents the service activities through a few representative sectors such as business services and other services.

In addition, Statistics Canada's I/O tables contain only one manufacturing sector as our primary data source because Statistics Canada's, "*The Input-Output Structure of the Canadian Economy*", presents only a solitary manufacturing sector. Representing all manufacturing activities through a single manufacturing industry greatly limits the capability of the model in dealing with industry sector demand-side policy analysis. CERI employed the same approach, as mentioned above, to

[3] We followed these steps in our disaggregating methodology. Using Statistics Canada's publication, CAPP and other official data sources, for each aggregate sector, we calculated the "total production values" for year 2003 using 2003 prices. Then, we made a comparison of this number with the actual number in the I/O tables and made adjustments if they differed. Afterwards, we calculated the "share" coefficients for each sub-sector within the sector. CERI used these share coefficients to disaggregate the aggregated sectors.

disaggregate manufacturing sector. CERI's Multi-Regional I/O model breaks down the single manufacturing sector into: Refinery, Petrochemical, and Other Manufacturing. After incorporating disaggregation, the CERI Multi-Regional I/O model incorporates a 31-sector square transaction table. Table 2.1 provides a brief description of these aforementioned sectors or commodities.

**Table 2.1**
**Sectors/Commodities in CERI Multi-Regional I/O Model**

| Serial No. | Sector or Commodity | Examples of activities under the sector or commodity |
|---|---|---|
| 1 | Crop and animal production | Farming of wheat, corn, rice, soybean, tobacco, cotton, hay, vegetables and fruits; greenhouse, nursery, and floriculture production; cattle ranching and farming; dairy, egg and meat production; animal aquaculture |
| 2 | Forestry and logging | Timber tract operations; forestry products: logs, bolts, poles and other wood in the rough; pulpwood; custom forestry; forest nurseries and gathering of forest products; logging. |
| 3 | Fishing, Hunting and Trapping | Fish and seafood: fresh, chilled, or frozen; animal aquaculture products: fresh, chilled or frozen; hunting and trapping products |
| 4 | Support Activities for Agriculture and Forestry | Support activities for crop, animal and forestry productions; services incidental to agriculture and forestry including crop and animal production, e.g., veterinary fees, tree pruning, and surgery services, animal (pet) training, grooming, and boarding services |
| 5 | Conventional Oil[4] | Conventional oil, all activities e.g., extraction and services incidental to conventional oil |
| 6 | Oil sands | Oil sands, all activities e.g., extraction and services incidental to oil sands |
| 7 | Natural Gas and NGL | Natural gas, NGL, all activities e.g., extraction and services incidental to natural gas and NGL |
| 8 | Coal | Coal mining, activities and services incidental to coal mining |
| 9 | Other Mining | Mining of iron, metal, and gold and silver ores; copper, nickel, lead, and zinc ore mining; non-metallic mineral mining and quarrying; sand, gravel, clay, ceramic and refractory, limestone, granite mineral mining and quarrying; potash, soda, borate and phosphate mining; all related support activities. |
| 10 | Refinery | Petroleum and coal products; motor gasoline and other fuel oils; tar and pitch, LPG, asphalt, petrochemical feed stocks, coke; petroleum refineries |
| 11 | Petrochemical | Chemicals and polymers: resin, rubber, plastics, and fibers and filaments; pesticides and fertilizers; etc |
| 12 | Other Manufacturing | Food, beverage and tobacco; textile and apparel; leather and footwear; wood products; furniture and fixtures; pulp and paper; printing; pharmaceuticals and medicine; non-metallic mineral, lime, glass, clay and cement; primary metal, iron, aluminum and other metals; fabricated metal, machinery and equipment, electrical, electronic and transportation equipment, etc. |

[4] Statistics Canada reports the oil, gas, coal and other mining as one sector due to some confidentiality issues. CERI, uses an in-house developed approach to disaggregate this sector to five sectors: Oil Sands, Conventional Oil, Gas+NGL, Coal and other mining.

**Table 2.1 (con't)**

| | | |
|---|---|---|
| 13 | Construction | Construction of residential, commercial and industrial buildings; highways, streets, and bridges; gas and oil engineering; water and sewer system; electric power and communication lines; repair construction |
| 14 | Transportation and Warehousing | Roads, railways; air, water & pipeline transportation services; postal service, couriers and messengers; warehousing and storage; information and communication; sightseeing & support activities |
| 15 | Transportation margins | Transportation margins |
| 16 | Utilities | Electric power generation, transmission, and distribution; natural gas distribution; water & sewage |
| 17 | Wholesale Trade | Wholesaling services and margins |
| 18 | Retail Trade | Retailing services and margins |
| 19 | Information and Cultural Industries | Motion picture and sound recording; radio and TV broadcasting and telecommunications; publishing; information and data processing services |
| 20 | Finance, Insurance, Real Estate and Rental and Leasing | Insurance carriers; monetary authorities; banking and credit intermediaries; lessors of real estate; renting and leasing services |
| 21 | Professional, Scientific and Technical Services | Advertising and related services; legal, accounting and architectural; engineering and related services; computer system design |
| 22 | Administrative and Support, Waste Management and Remediation Services | Travel arrangement and reservation services; investigation and security services; services to buildings and dwellings; waste management services |
| 23 | Educational Services | Universities; elementary and secondary schools; community colleges and educational support services |
| 24 | Health Care and Social Assistance | Hospitals; offices of physicians and dentists; misc. ambulatory health care services; nursing and residential care facilities; medical laboratories; child and senior care services |
| 25 | Arts, Entertainment and Recreation | Performing arts; spectator sports and related industries; heritage institutions; gambling, amusement, and recreation industries |
| 26 | Accommodation and Food Services | Traveler accommodation, recreational vehicle (RV) parks and recreational camps; rooming and boarding houses; food services and drinking establishments |
| 27 | Other Services (Except Public Administration) | Repair and maintenance services; religious, grant-making, civic, and professional organizations; personal and laundry services; private households |
| 28 | Operating, Office, Cafeteria and Laboratory Supplies | Operating supplies; office supplies; cafeteria supplies; laboratory supplies |
| 29 | Travel, Entertainment, Advertising and Promotion | Travel and entertainment; advertising and promotion |
| 30 | Non-Profit Institutions Serving Households | Religious organizations; non-profit welfare organizations; non-profit sports and recreation clubs; non-profit education services and institutions |
| 31 | Government Sector | Hospitals and government nursing and residential care facilities; universities and government education services; other municipal government services; other provincial and territorial government services; other federal government services including defense |

Based on a standard I/O model notation, and considering total gross outputs vector (GO), final demand vector (FD), and all calculated within interprovincial technical coefficient matrixes, the following relationship in Multi-Regional I/O context holds as:

A × GO + C × GO + R′ × GO + FD = GO

This gives (I – A – C – R′) × GO = FD

Rewriting finally yields GO = (I – A – C - R)$^{-1}$ × FD, provided that (I – A – C - R) is a nonsingular matrix.

As is the case for standard I/O models, the impact of an industry, such as the oil sands industry, is calculated by modeling the relationship between total gross outputs and final demand as follows:

$$\Delta GO = [I - A - C - R']^{-1} \times \Delta FD \qquad \text{(Equation I)}$$

Where:

ΔGO Changes (or increases) in total gross outputs of all provinces and territories, at the sectoral level, due to construction and operation of projects (i.e., oil sands). This is a 403×1 vector.

I Is a 403×403 matrix. I is an identity matrix, a matrix with 1 for diagonal elements and zero for the rest of the matrix.

A Is a 403×403 block diagonal matrix of technical coefficients at the sectoral level for Canada. It is composed of 13 blocks so that each block is a 31×31 matrix corresponding to a province (or territory) input technical coefficient matrix.[5] An element of such matrix is derived dividing the value of a commodity used in a sector by the total output of that sector. The element represents requirements of a commodity in a sector to produce one unit of output from that sector.

C Is a 403×403 matrix at the sectoral level for Canada. Each of its elements measures the final consumption shares in a sector's total gross output in a province (or territory).

R′ Is a 403×403 transposed matrix of interprovincial trade coefficients. It includes import and export shares of a sector's total output in a province or territory. Each element on the row of this matrix measures the share of export to a particular sector in a province from a given sector in another province or territory.[6]

[5] In other words, one can say all 13 provinces' input technical coefficients matrices are stacked together in construction of a diagonal block matrix at the national level.
[6] In particular, this matrix is a bridge matrix which connects a province to other province through import and export coefficients.

$\Delta$FD Is a 403×1 vector of changes (or increases) in final demand at the sectoral level outputs from Canada resulted from any change in the final demand components in a province or territory, including commodity directly demanded (or purchased) for the construction and development of any sector in a province or territory.

The calculation of total impact is based on the multiplication of direct impact and the inverted matrix. Based on the direct impact on a sector, the Equation (I), above, is used to estimate all the direct, indirect and induced effects on all sectors in all provinces, particularly in terms of changes in consumption, imports, exports, production, employment, and net taxes. The direct impact is referred to $\Delta F$ in Equation (I). The change in final demand ($\Delta F$) consists of various types of investment expenditures, changes in inventories, and government expenditures. In the current model, the personal expenditures are not part of the final demand and have been endogenized to accommodate the induced impact. Almost 50 percent of the GDP (total final demand) is composed of personal expenditure. Therefore, CERI takes a heroic approach and shocked the final demand by only half of the operating costs.

Direct impacts are quantitative estimations that are made of the main impact of the programs, in the form of an increase in final demand (increase in public spending, increase in consumption, increase in infrastructure investment, etc). The assumption of increased demand includes a breakdown per sector, so that it can be translated into the following matrix notation:

Direct, indirect and induced impacts:

$$\Delta GO = [I - A - C - R']^{-1} \times \Delta F \qquad \text{(Equation II)}$$

Direct and indirect impacts:

$$\Delta GO = [I - A - R']^{-1} \times \Delta F \qquad \text{(Equation III)}$$

The difference between Equations (II) and (III) is referred to as the induced impact of any changes in final demand components.

Once the impact on output (change in total gross outputs) is calculated, the calculations of impacts on GDP, household income, employment, taxes, and so forth, are straightforward. In particular, as previously mentioned the base year for the I/O tables used in this report is 2003. CERI utilized the tax coefficients derived from these tables to calculate the total collected taxes. It is worth mentioning that the disaggregation of the collected taxes to federal and provincial taxes is based on the figures and ratios from the *Finances of the Nation*[7], where these numbers reflect the tax structure of the Canadian economy in the year of 2006. CERI acknowledges that there have been changes to the corporate income tax structure and the goods and services sales taxes (GST), since 2006. The new tax regime will result in changes in tax figures and other numbers in the economy since the business will respond to the new incentives. This will be reflected in the upcoming I/O tables released by Statistics Canada.

[7] Treff, Karin and David Perry, Finances of the Nation 2007.

These impacts are estimated at the industry level using the ratio of each (i.e., GDP) to total gross outputs. Using the technical Multi-Regional I/O table, CERI is able to perform the usual I/O analysis at the provincial and national levels.

### 2.3 CERI's I/O Expertise

CERI has successfully conducted a number of I/O analyses in the past. The I/O modeling approach used in this analysis is an extension of a previous CERI study entitled "Economic Impacts of Alberta's Oil Sands", originally released in 2005. The most recent edition was released in September 2008. Table 2.2 below highlights several differences between the 2008 and the ambitious, current study.

**Table 2.2**
**Differences Between Studies**

| | **Economic Impacts of Alberta's Oil Sands September, 2005** | **Economic Impacts of Petroleum Industry in Canada Spring, 2009** |
|---|---|---|
| Data Sources | I/O tables 2000 | Most recent I/O tables |
| Industry Scope | Oil sands only | Petroleum industry as defined in Methodology section below |
| Geographic Scope | Alberta, Ontario, Quebec, Canada,<br>and rest of the world | Each province and territory and Canada, |
| Interprovincial Comparative Advantages | None | Yes |

This study is extended to capture economic impacts of the petroleum industry in Canada applying the Multi-Regional I/O tables, as well as includes interprovincial comparative advantage. The geographical scope is also extended to each province and territory and the rest of Canada.

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# CHAPTER 3
# DATA AND KEY ASSUMPTIONS

This chapter discusses briefly the data and key assumptions of this study. It is divided into two parts: data sources and assumptions.

## 3.1 Data Sources

The National Accounts and I/O tables in Canada were developed at the conclusion of the Second World War. Tables in the present format, however, were first published in 1969 for the base year 1961. The I/O accounts are one of four main accounts that are published by the CSNEA, the others being income and expenditure accounts, financial and wealth accounts, and balance of payments accounts.

The I/O accounts are calculated at the national, provincial and territorial level, but on an annual basis only.[8] These tables are available at different levels of aggregation[9] on the Canadian Socio-Economic Information Management System (CANSIM) Tables 381-0009 to 381-0014. Provincial I/O data are also available on an occasional basis.

The framework of the Canadian I/O system consists of the following three basic tables:

Gross output of commodities (goods and services) by producing industries;

Industry use of commodities and primary inputs (the factors of production, labour and capital, plus other charges against production such as net indirect taxes); and

Final consumption and investment plus any direct purchases of primary inputs by final demand sectors.

Figure 3.1 is a schematic of the I/O system, and combines features of both the Canadian system and the more traditional single matrix presentation.

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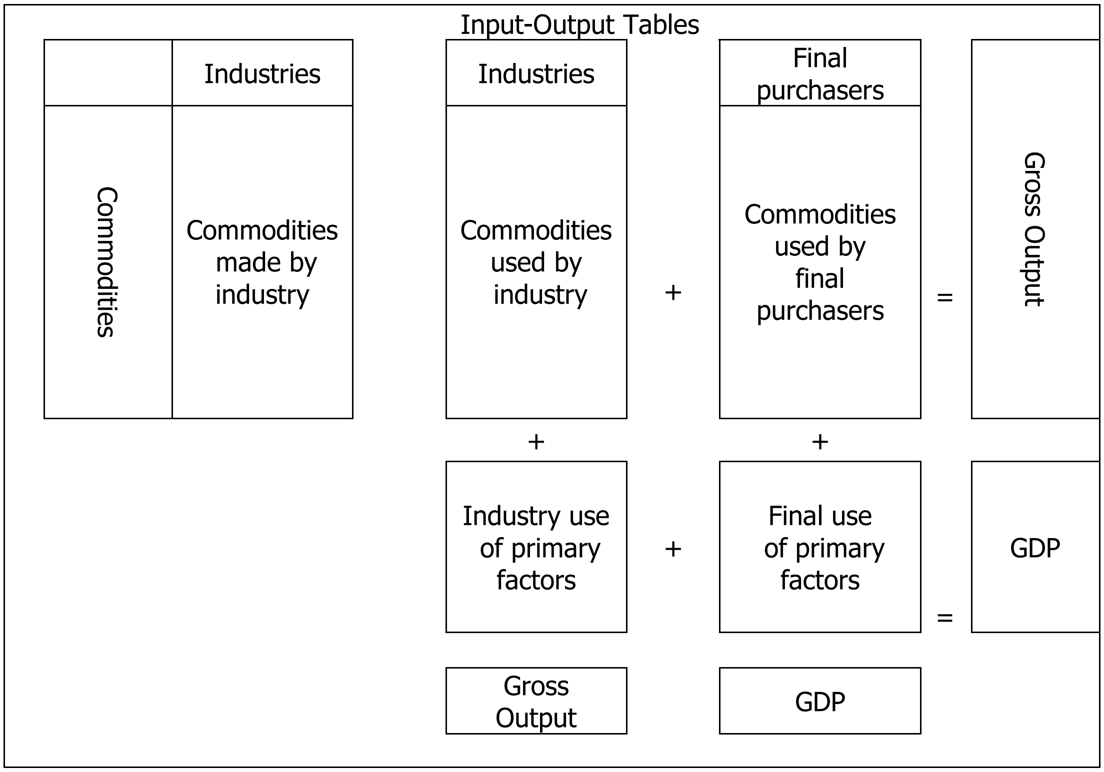
[8] The I/O tables and models, published annually by Statistics Canada, are entitled "The Input-Output Structure of the Canadian Economy". This document covers the basic concepts related to the I/O tables. Each year, two years of data are reported; the latest year is considered preliminary and the previous one is considered final. There are also many documents which are available on request from I/O division.

[9] The I/O Tables of this publication are stored in CANSIM at the Small (S) level, Medium (M) level and Link (L) level of aggregation.

**Figure 3.1**
**A Schematic of the Canadian Input-Output System**




Source: A User Guide to the Canadian System of national Accounts, Statistics Canada, Catalogue No. 13-589E, November 1989.

The statistical presentation of the Canadian system differs from the traditional conceptual framework, which is frequently presented in a single matrix divided into four quadrants; the inter industry flow of commodities produced and consumed in the production process, the final demand use of outputs, the industrial use of primary inputs, and the final demand sectors' use of primary inputs.

## 3.2 Assumptions

The main assumption of any I/O analysis is that the economy is in equilibrium. Despite partial equilibrium analysis, it is assumed in the general equilibrium (GE) approach that the economy as a whole is in equilibrium. This is a realistic assumption in the long run, as it is difficult to imagine an economy remaining in disequilibrium for a long time period.

A second important assumption in I/O analysis is the linear relationship between inputs and outputs in the economy. Each sector uses a variety of inputs in a linear fashion to produce various final products. Though the form of the production function is simple, this could be viewed as an approximation of the real world's production function. A very interesting aspect of this assumption is the constant return to scale (CRS) property of the production function, which turned out to be a proven property in the real world economy. Though the linearity of the production function gives a constant average and marginal products, these are justified if the analysis focuses to the long-run rather than the short-run.

Although the I/O approach has been widely used around the world for economic impact assessment, there are certain limitations that should be noted. I/O matrices are limited to the estimation effect on demand, rather than supply. Therefore, they do not take into account important objectives such as lasting effects on productive potential. Most effects on supply, which are likely to lead to a sustainable increase in the growth rate of assisted sectors (or provinces) and enable them to catch up with more developed sectors (or provinces), are completely disregarded. Some of these overlooked points include: the creation of new productive capacity, improvement of the training and education of the workforce, construction of infrastructure, productivity gains throughout the economy, spread of technological progress, and intensity of high-tech activities in the productive sector. All these effects on supply can transform productive capacity in a lasting and irreversible manner. These cannot be estimated using this multi-regional I/O tool.

In particular, several other well-known limitations of I/O approach are discussed below:

***Static relationships.*** I/O coefficients are based on value relationships between one sector's outputs to other sectors. The relationship and, thus, the stability of coefficients could change over time due to several factors including:

Change in the relative prices of commodities;

Technological change;

Change in productivity; and

Change in production scope and capacity utilization.

Since these attributes cannot be incorporated in a static I/O model, these models are primarily used over a short-run time horizon, where relative prices and productivity are expected to remain relatively constant. Hence, over a longer period, static I/O models are not the best tools for economic impact analysis. GE models or macroeconomic models accounting for the factors mentioned above could be more appropriate. Moreover I/O models and other static macroeconomic models and general equilibrium models do not account for sectoral dynamics and adjustment in an economy.

***Unlimited resources or supplies.*** The I/O approach simplistically assumes that there are no supply or resources constraints. In reality, in the short run, increasing economic activities in a particular sector of the economy may put pressure on wages and salaries. However, in the long run, the economy adjusts through the mobility of the factors of production (i.e., labour and capital).

***Lack of capacity to capture price, investment and production interactions***. An I/O model is incapable of representing the feedback mechanism between price change, investment and production. For example, an increase in oil price provides a signal to investors to increase investment. The increase in investment would add productive capacity (more drilling) and also the production. However, this type of interaction cannot be modeled in a simple I/O model.

# CHAPTER 4
# ECONOMIC IMPACTS: ALBERTA

This chapter discusses the economic impacts for the province of Alberta. It is divided into six sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Alberta. The following five sections discuss and review the economic impacts of conventional oil resources, conventional gas resources, CBM resources, oil sands and major capital projects in the province. Each section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces and territories. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 4.1 Background

As previously mentioned, this section describes the reserves, production, and expenditures of the petroleum industry in the province of Alberta. In this section, the methodology that is used for regrouping components of the petroleum industry's expenditures, and their disaggregation into oil and natural gas is demonstrated.

It is important to note that while oil sands are a massive resource, an estimated 1.7 trillion barrels of total bitumen in-place, this is a unique resource that deserves its own section. With 173 billion barrels of estimated recoverable bitumen, the resource places Alberta second to only Saudi Arabia in total reserves. Section 4.4 discusses the oil sands in greater detail.

### 4.1.1 Reserves and Production

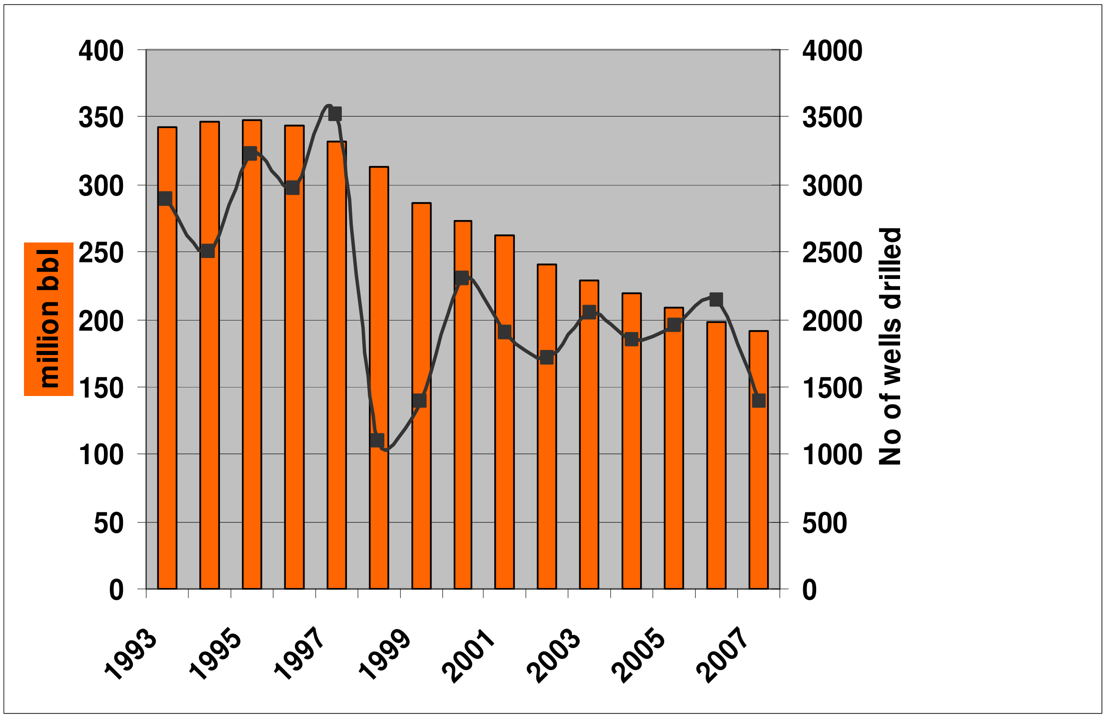
While Canada's energy industry began in Ontario, Alberta is certainly its heart and soul. Alberta leads the industry in reserves and production, and has since the Second World War. The following section discusses Alberta's conventional oil reserves and production, as well as its marketable natural gas reserves and production.

According to the Canadian Association of Petroleum Producers (CAPP), the remaining established reserves of crude oil in Alberta are 1.5 billion barrels. Estimated as of December 2006, this is a net decrease of 2.3 percent from the previous year. It is important to note that this estimate does not include the oil sands, an unconventional resource.

Crude oil production has been on a downward trend since 1995, declining on an average annual rate of 4 percent over this time period. In 2007, Alberta produced approximately 191 million barrels of crude oil. The number of oil wells drilled declined by almost half from 2,895 wells in 1993 to 1,393 wells in 2007. Interestingly, the number of oil wells declined from over 2,000 wells from 2006. Crude oil production and number of wells drilled are illustrated in Figure 4.1.

Alberta's conventional oil reserves production ratio is approximately 7.5 years.

**Figure 4.1**
**Alberta Conventional Oil Production and Number of Wells Drilled**
**1993 - 2007**



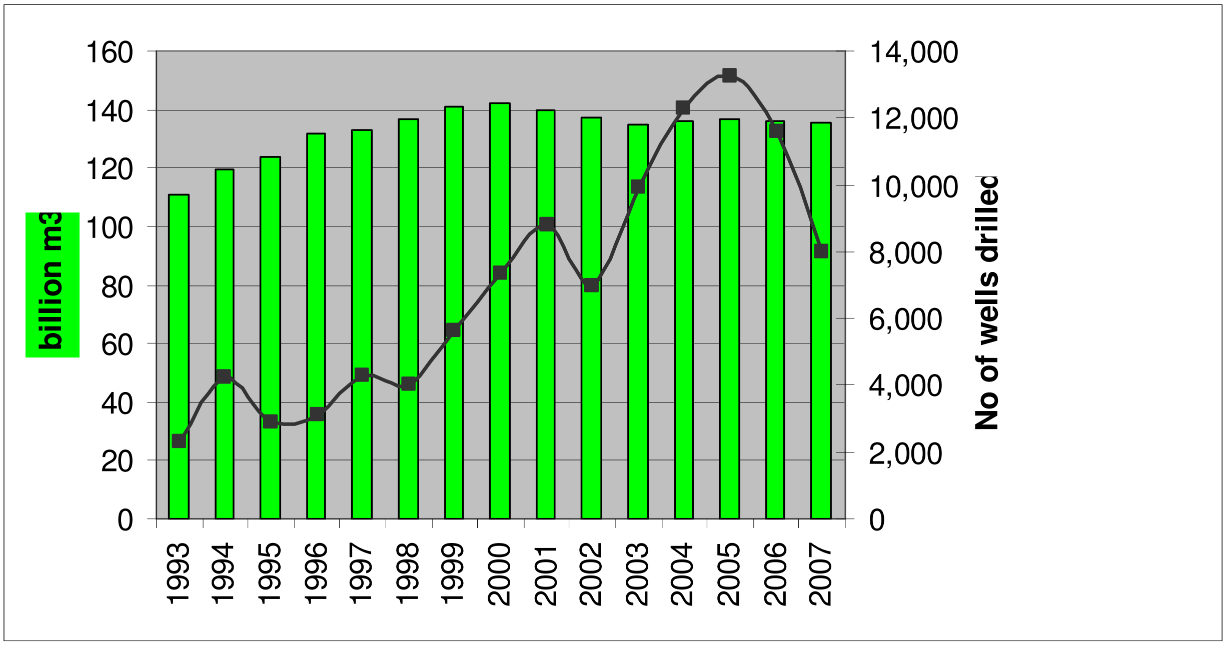

Source: CAPP, Statistical Handbook, September 2008.

According to CAPP, as of December 2006, the remaining established reserves of marketable natural gas are 1,131 billion $m^3$, a decrease of almost 22 billion $m^3$ from the previous year.

Figure 4.2 illustrates marketable natural gas production and the number of wells drilled between 1993 and 2007. Marketable natural gas production in Alberta increased from 131 billion $m^3$ in 1993 to 136 billion $m^3$ in 2007, an average annual growth rate of 1.5 percent. Over the same period, the number of gas wells drilled increased from 2,287 wells in 1993 to 8,006 wells in 2007. The number of gas well drilled peaked at 13,268 in 2005, and has subsequently declined rapidly. This is especially the case this past year, due to the global recession and the North American natural gas supply surplus.

The natural gas reserves production ratio is 8 years.

**Figure 4.2**
**Alberta Marketable Natural Gas Production and Number of Wells Drilled**
**1993 - 2007**




Source: CAPP, Statistical Handbook, September 2008.

### 4.1.2 Expenditures of the Petroleum Industry in Alberta

The CAPP[10] reports the net cash expenditures (investment) of petroleum industry (combined oil and gas) for exploration, development, operating and royalties as follows.

A- Exploration
- A1- Geological & Geophysical
- A2- Drilling
- A3- Land

B- Development
- B1- Drilling
- B2- Field Equipment
- B3- EOR
- B4- Gas Plant

C- Operating
- C1- Wells & Flow lines
- C2- Gas Plants

D- Royalties

According to CAPP[11], in 2007 approximately $39.4 billion dollars were spent in the petroleum industry in Alberta. The largest investment expenditures were approximately 43 percent for

[10] Canadian Association of Petroleum Producers, *Statistical Handbook, For Canada's Upstream Petroleum Industry,* http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=132330, September 2008.

development. Operating, royalties and exploration follow at 26 percent, 20 percent and 11 percent, respectively.

For the purpose of using the above information in the I/O model, CERI considers that the investment expenditures are incurred in drilling each well. If the well is successful, then further investment expenditures are required to complete the well, and to connect it to processing facilities as well as the pipeline grid (field equipment). Throughout production, there are further costs incurred, mainly for the operating and maintenance of existing field equipments. Once the well comes on stream, then revenue generation starts, and subsequently royalty payment, which is another type of expense to the petroleum industry will commence.

Table 4.1 summarizes the methodology, which will be referred to in latter sections, that has been used for regrouping the components of petroleum expenditures to the following: drilling investment expenditure, field equipment investment expenditure and operating expenditure.

**Table 4.1**
**Disaggregation of Oil and Gas Expenditures**

| Crude Oil | Natural Gas |
|---|---|
| Drilling Expenditure:<br>A1 + A2 + B1 | Drilling Expenditure:<br>A1 + A2 + B1 |
| Field Equipment Expenditure:<br>B2 + B3 | Field Equipment Expenditure:<br>B2 + B4 |
| Operating Expenditure:<br>C1 | Operating Expenditure:<br>C1 + C2 |

Drilling Investment Expenditure

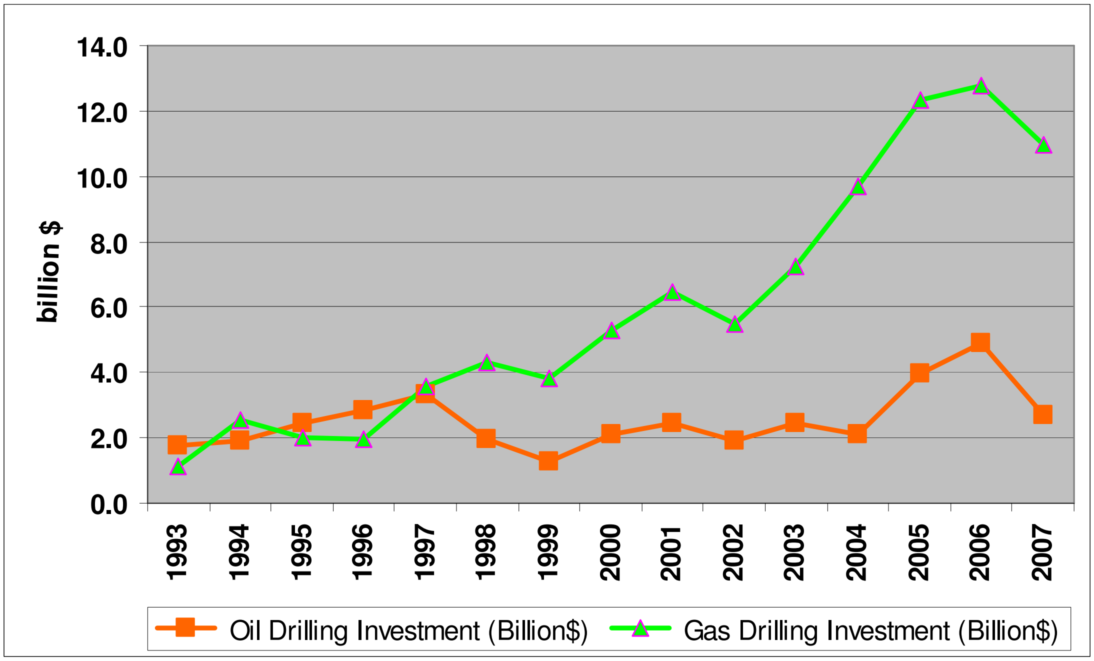
Drilling expenditures of the petroleum industry (A1, A2, and B1) are taken from CAPP's Statistical Handbook, released in September 2008. These expenditures are disaggregated into oil and gas in proportion to oil and gas wells drilled.

Figure 4.3 shows oil and gas drilling investment in Alberta. Oil drilling expenditure increased from $1.7 billion dollars in 1993 to $2.7 billion dollars in 2007, while the number of oil wells drilled declined from 2,895 wells to 1,393 wells. This corresponds with higher drilling costs associated with producing from unconventional resources. Over the same time period, gas-drilling investment climbed from $1.1 billion dollars to almost $11.0 billion dollars, accompanied by an increased number of gas wells drilled (completed) from 2,287 wells to 8,006 wells.

Figure 4.3 also illustrates that between 1993 and 2007, Alberta's crude oil and natural gas expenditures peaked in 2006 at $4.8 billion and $12.7 billion dollars, respectively. However, both sectors declined by almost $2 billion dollars expenditures one year later.

[11] Ibid.

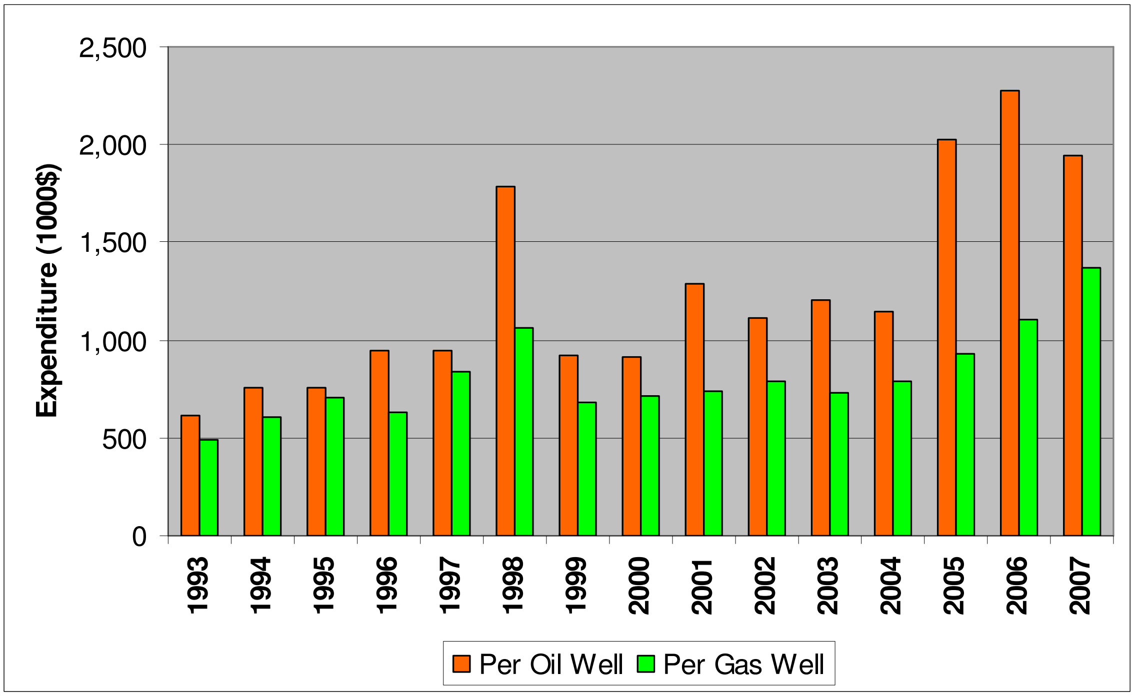
**Figure 4.3**
**Alberta Oil and Gas Drilling Investment**
**1993 - 2007**




Source: CAPP, Statistical Handbook, September 2008.

In contrast to total drilling investments, Alberta drilling investments per well have been greater for oil than for natural gas over the 1993-2007 period—albeit barely in 1995. This is illustrated in Figure 4.4. In 2006 and 2007, oil drilling investments per well were almost twice than that of natural gas, largely because the average oil well was about twice as deep as the average gas well.

**Figure 4.4**
**Alberta Oil and Gas Drilling Investment per Well Drilled**
**1993 - 2007**



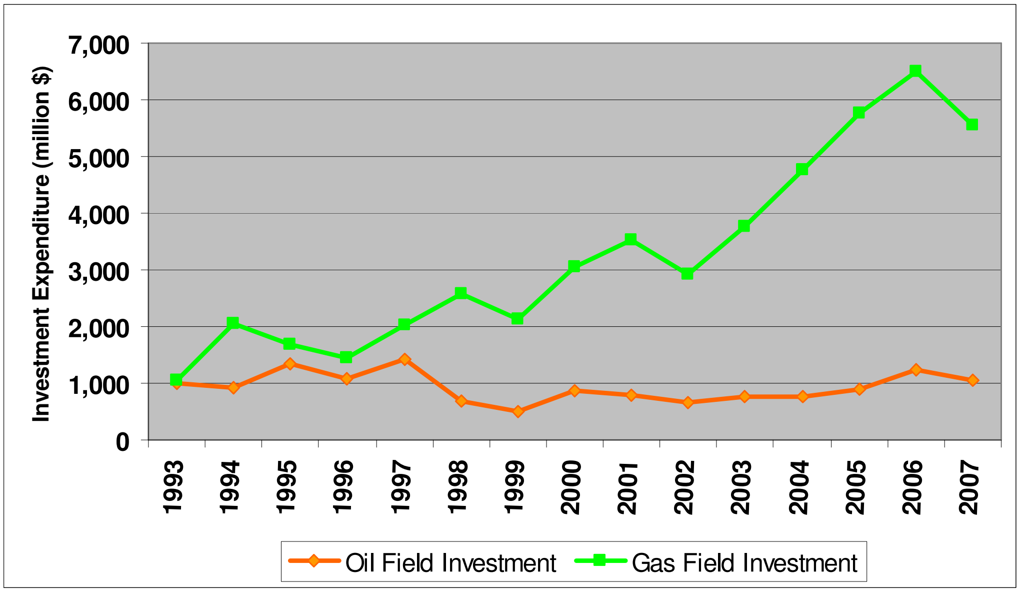

Source: CAPP, Statistical Handbook, September 2008.

Field Investment Expenditure

The major field equipment investments are related to field facilities, crude oil battery, and gathering systems. CAPP reports combined oil and gas field equipment investment expenditure (B2). CERI has disaggregated the above investment into oil and gas in proportion to the number of wells drilled. Enhanced oil recovery expenditure (B3) was added to oil field investment; similarly, gas plant expenditure (B4) was added to the gas field investment.

Figure 4.5 shows oil and gas field investment in Alberta. From 1993 to 2007 total investment of gas field was higher than corresponding figure for oil.

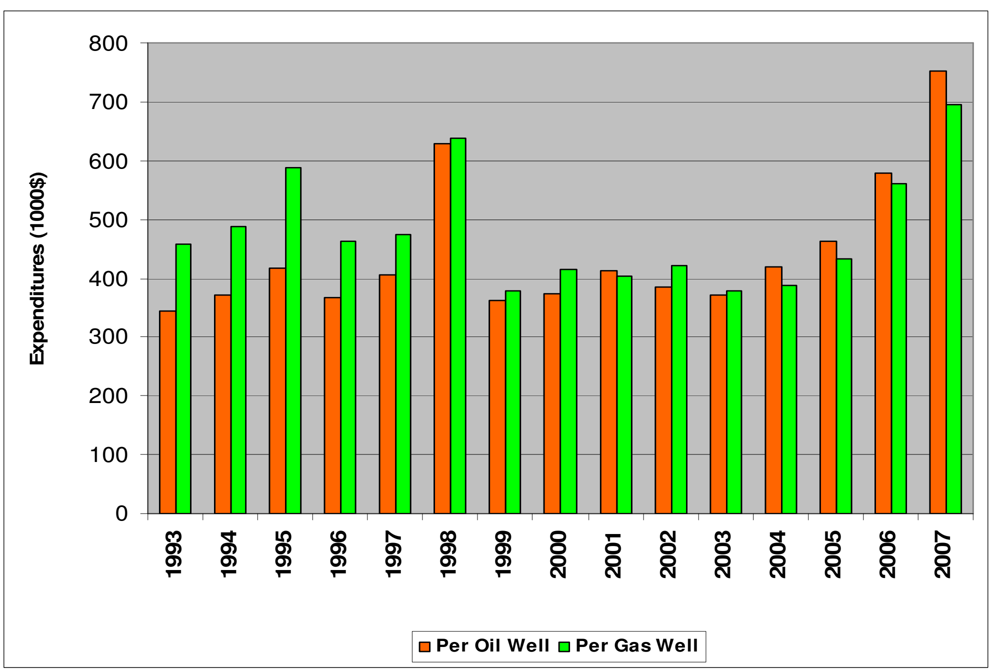
**Figure 4.5**
**Alberta Oil and Gas Field Investment**
**1993 - 2007**




Source: CAPP, Statistical Handbook, September 2008.

However, over the same time period oil field investment was higher on a per well basis. Figure 4.6 illustrates oil and gas field investment per well drilled in Alberta.

**Figure 4.6**
**Alberta Oil and Gas Field Investment per Well Drilled**
**1993 - 2007**

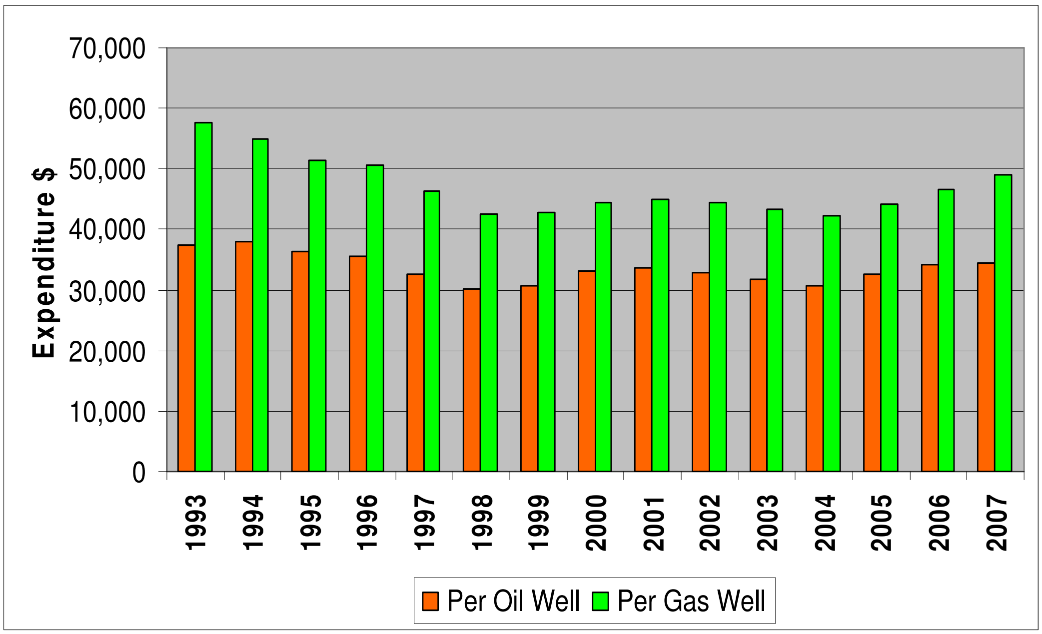



Source: CAPP, Statistical Handbook, September 2008.

<u>Operating Expenditure</u>

To estimate per well operating expenditures, CERI assumes that "wells and flow lines" operating expenditures (C1) for oil and gas are the same, and therefore divides C1 by the total cumulative combined oil and gas wells drilled. Gas plant operating expenditure (C2) per cumulative well is added to the operating expenditure of gas wells. This is illustrated Figure 4.7.

**Figure 4.7**
**Alberta Oil and Gas Operating Expenditures per Cumulative Successful Well**
**1993 - 2007**




Source: CAPP, Statistical Handbook, September 2008.

Operating expenditures per gas well were higher than oil for each year observed in Figure 4.7. For the period 2003 to 2007, the average operating expenditure per cumulative successful oil well is $35,000 and per cumulative successful gas well is $45,000.

## 4.2 Conventional Oil Resources

### 4.2.1 Background

The first major conventional oil field in Alberta was discovered at Turner Valley in 1914. However, it was the discovery at Leduc in 1947 that transformed the energy industry in the province.[12] Since that pivotal moment, however, many more oil fields have been discovered, and by December 2007 there were 12,243 light, medium and heavy oil pools in the province. These

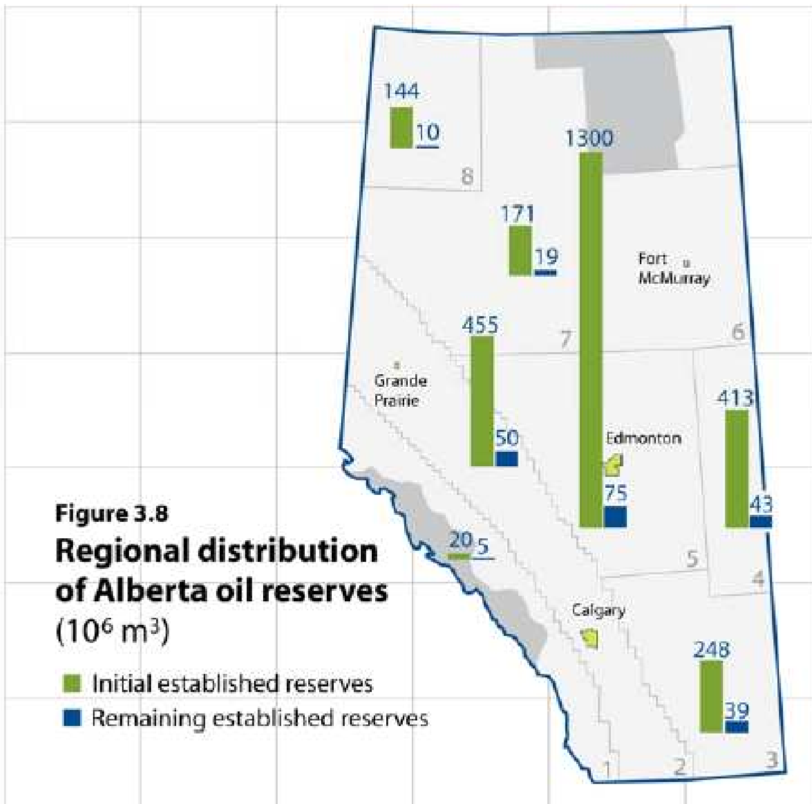
[12] Alberta Department of Energy, http://www.energy.gov.ab.ca/Oil/Oil.asp, 2008.

pools make up an estimated 240.7 million $m^3$ of remaining established conventional oil reserves.[13]

In 2007 there were 1,791 successful conventional oil wells drilled, which increased the total number of producing oil wells in Alberta to 38,500. On average, these wells each produced 2.3 $m^3/d$, resulting in approximately 83,500 $m^3/d$ of conventional oil produced in the province.[14]

Figure 4.8 shows the distribution of Alberta's established conventional oil reserves:[15]

**Figure 4.8**
**Oil Reserves in Alberta**




Source: Energy Resources Conservation Board.

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[13] Energy Resources Conservation Board (ERCB), *Alberta's Energy Reserves 2007 and Supply Outlook 2008-2017 (ST98-2008)*, 2008.

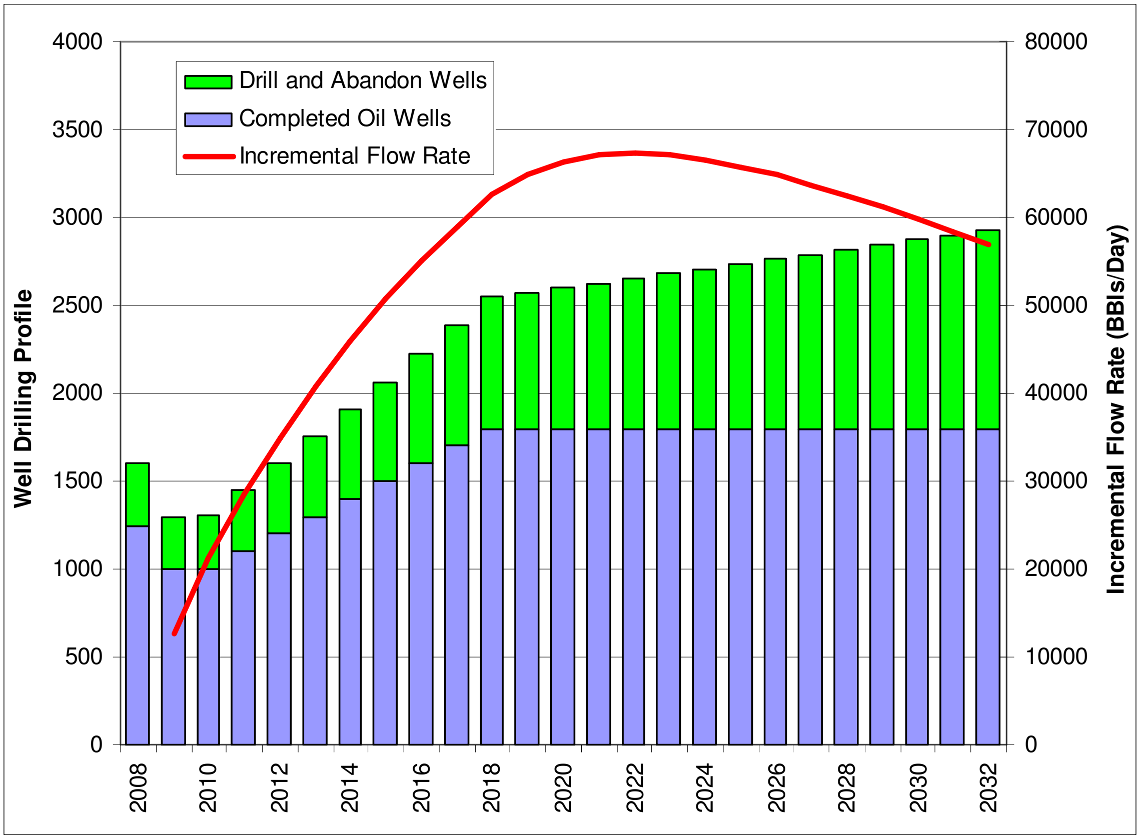
[14] Alberta Department of Energy, Alberta's *Energy Industry: An Overview 2007*. http://www.energy.gov.ab.ca/Org/pdfs/Alberta_ Energy_Overview.pdf

[15] Energy Resources Conservation Board, *ST98-2008*.

### 4.2.2 Forecasts

Figure 4.9 represents CERI's view of conventional oil resource developments broken down into forecasted new oil well connections and associated non-productive wells that are a typically part of the exploration and development activities. The latter are labeled dead and abandoned wells. This figure also indicates the resulting incremental oil flow rate from the completed oil wells.

**Figure 4.9**
**Well Drilling Profile and Incremental Flow Rate in Alberta (25-Year Forecast)**




### 4.2.3 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 4.2 and 4.3, 85 percent of the impacts are directly related to Alberta, with the remaining 15 percent being felt across the other provinces and territories.

**Table 4.2**
**Impacts Associated with Investment in Alberta**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 71,404 | 366 | 11,826 | 7,530 | 4,296 |
| **British Columbia** | 3,562 | 41 | 974 | 501 | 473 |
| **Manitoba** | 1,110 | 15 | 354 | 169 | 185 |
| **New Brunswick** | 103 | 2 | 36 | 18 | 18 |
| **Newfoundland & Labrador** | 152 | 2 | 47 | 20 | 27 |
| **Northwest Territories** | 110 | 1 | 28 | 19 | 9 |
| **Nova Scotia** | 148 | 3 | 52 | 25 | 28 |
| **Nunavut** | 15 | 0 | 8 | 6 | 2 |
| **Ontario** | 4,607 | 66 | 1,193 | 586 | 607 |
| **Prince Edward Island** | 21 | 0 | 8 | 4 | 4 |
| **Quebec** | 1,016 | 17 | 315 | 136 | 179 |
| **Saskatchewan** | 1,925 | 21 | 511 | 251 | 260 |
| **Yukon Territory** | 19 | 0 | 8 | 6 | 3 |
| **Canada** | 84,192 | 535 | 15,361 | 9,270 | 6,091 |

**Table 4.3**
**Impacts Associated with Operation in Alberta**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 35,851 | 184 | 5,938 | 3,781 | 2,157 |
| **British Columbia** | 1,789 | 21 | 489 | 252 | 237 |
| **Manitoba** | 557 | 8 | 178 | 85 | 93 |
| **New Brunswick** | 52 | 1 | 18 | 9 | 9 |
| **Newfoundland & Labrador** | 77 | 1 | 24 | 10 | 14 |
| **Northwest Territories** | 55 | 0 | 14 | 9 | 5 |
| **Nova Scotia** | 74 | 1 | 26 | 12 | 14 |
| **Nunavut** | 8 | 0 | 4 | 3 | 1 |
| **Ontario** | 2,313 | 33 | 599 | 294 | 305 |
| **Prince Edward Island** | 10 | 0 | 4 | 2 | 2 |
| **Quebec** | 510 | 8 | 158 | 68 | 90 |
| **Saskatchewan** | 966 | 10 | 257 | 126 | 130 |
| **Yukon Territory** | 9 | 0 | 4 | 3 | 1 |
| **Canada** | 42,271 | 269 | 7,713 | 4,654 | 3,058 |

In addition to the economic impacts listed in the previous tables, the royalties payable to the province of Alberta in regard to Alberta conventional oil, over the next 25-years, will be $3,452 million. On average, this equates to approximately $138 million per year.

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 4.10, Ontario receives 36 percent of the impacts, 28 percent for British Columbia, 15 percent for Saskatchewan and 8 percent for Quebec. Figures 4.11 and 4.12 show the similar impacts on employment, and federal and provincial taxes.

**Figure 4.10**
**Total GDP Impacts ($million)**

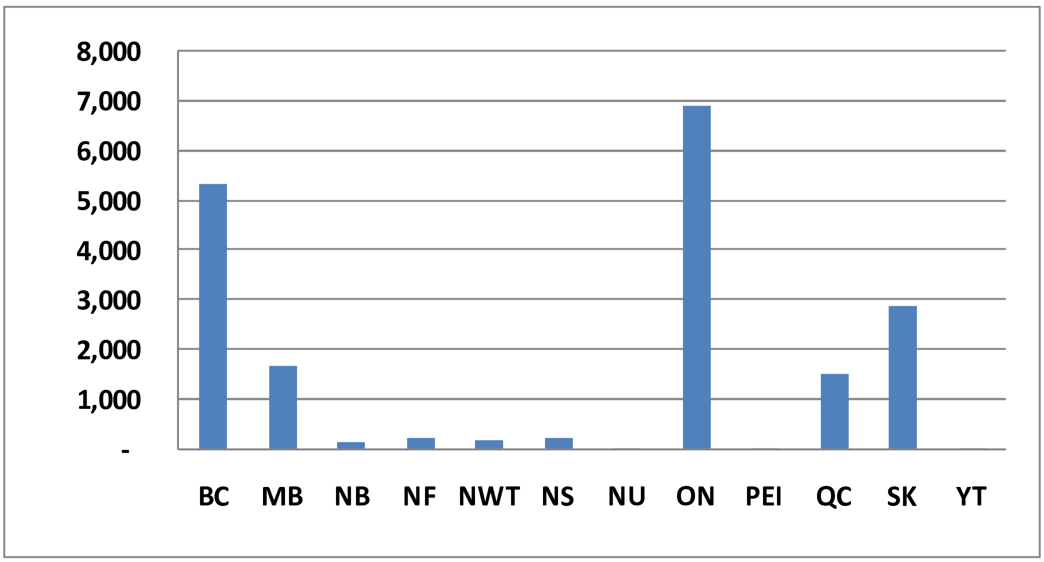


**Figure 4.11**
**Total Employment Impacts (thousand person years)**

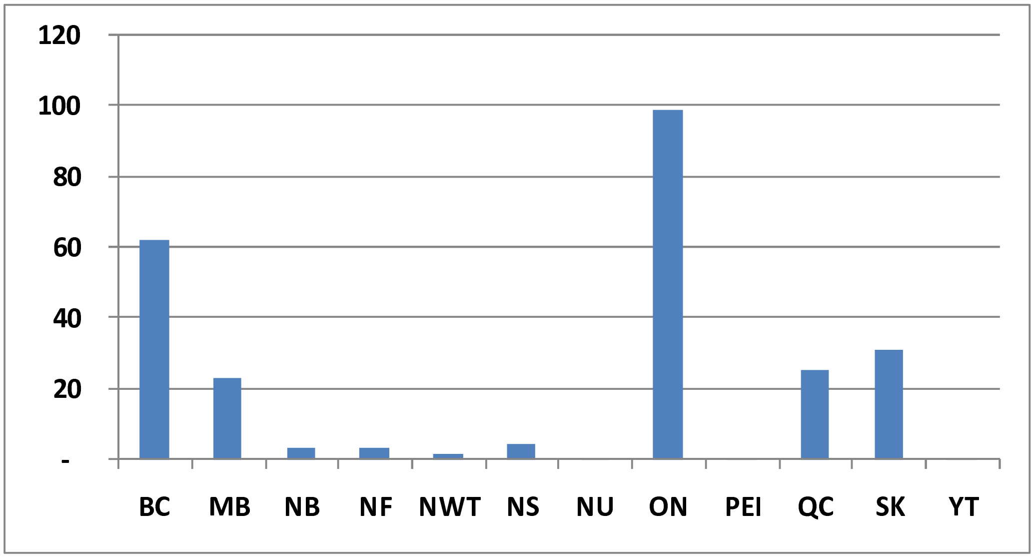
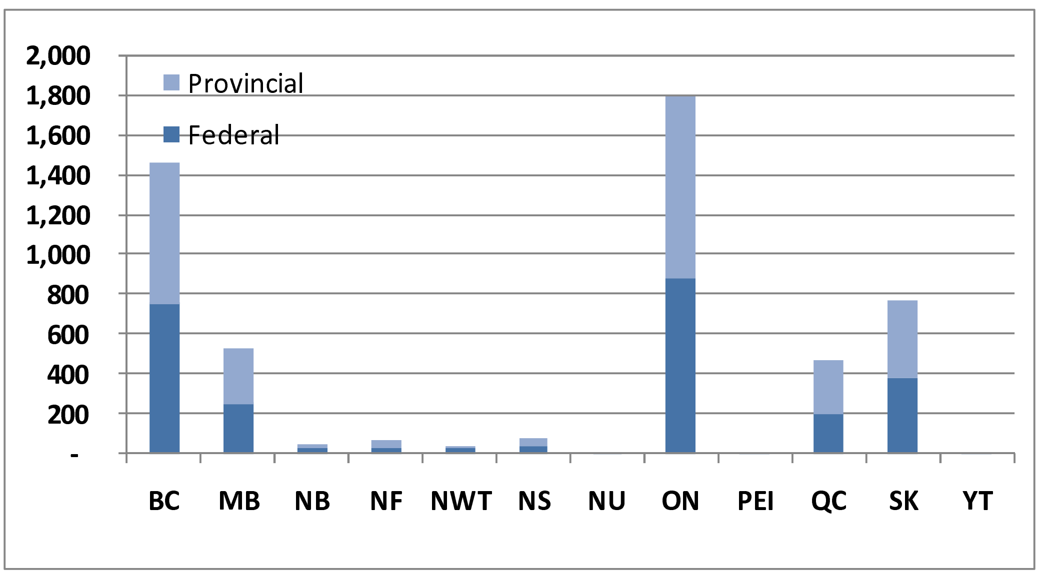



**Figure 4.12**
**Total Federal and Provincial Tax Impacts ($million)**




## 4.3 Conventional Gas Resources

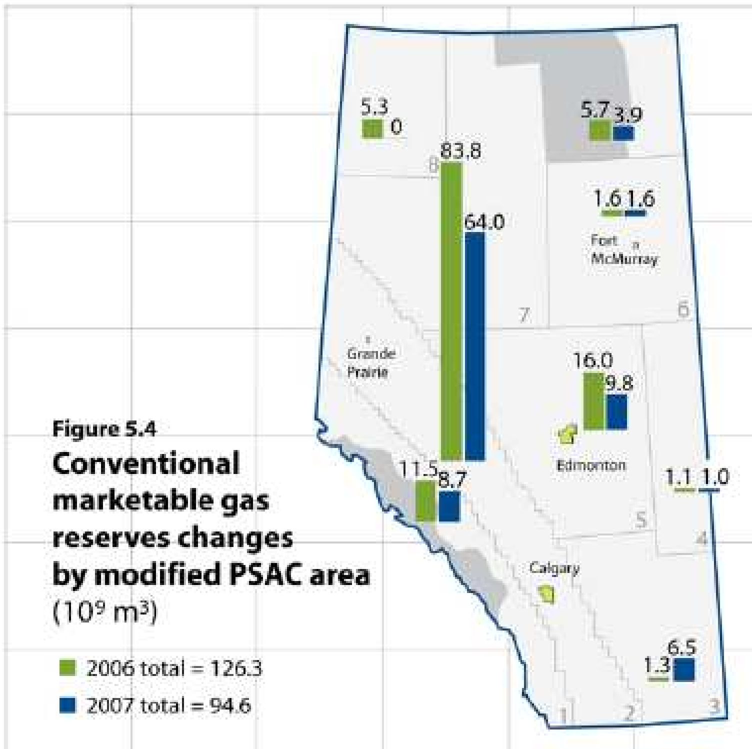
### 4.3.1 Background

Conventional natural gas was first discovered in Alberta in the late 19th century, and was used in Medicine Hat for cooking, lighting and heating. Commercial gas fields were discovered soon after at Bow Island, and by 1912, a 270 km pipeline had been built connecting Bow Island and

Calgary.[16] This was, however, only the beginning of the natural gas industry in Alberta. By 2007 established reserves of conventional gas amounted to 1,069 billion m$^3$.[17]

These reserves are concentrated mainly in central and southeastern Alberta, as seen in Figure 4.13.[18]

**Figure 4.13**
**Natural Gas Reserves in Alberta**




Source: Energy Resources Conservation Board.

Following the price decrease of natural gas in late 2006 and 2007, drilling in Alberta slowed by 24 percent to 9,220 wells. Despite this, production in 2007 only dropped by 4 percent to 133.7 billion m$^3$. Time delays of bringing wells on-line bolstered production, with more new gas wells being connected than were drilled in 2007.[19] By the end of 2007, there were 95,853 conventional gas wells operating in Alberta.[20]

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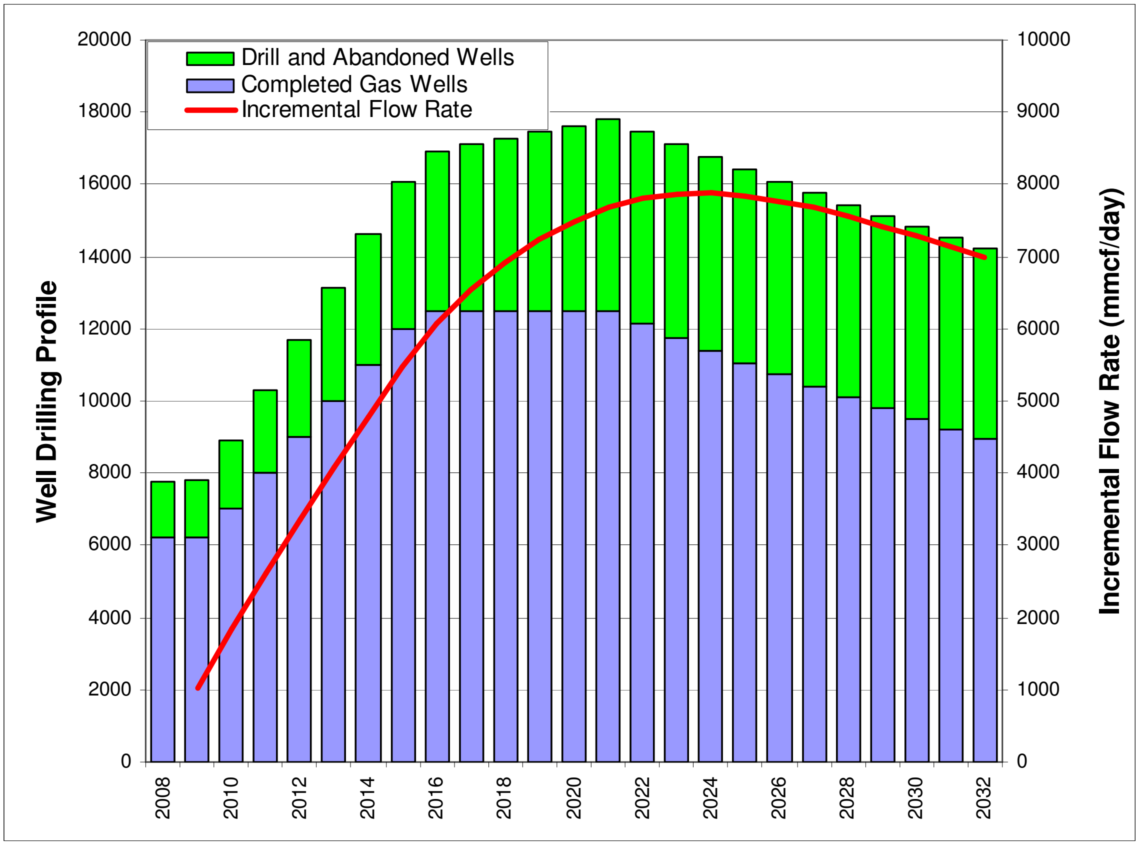
[16] Centre for Energy, *Alberta Energy Facts and Statistics,* http://www.centreforenergy.com/FactsStats/MapsCanada/AB-EnergyMap.asp
[17] Energy Resources Conservation Board (ERCB), *ST98-2008*.
[18] Ibid.
[19] Ibid.
[20] Centre for Energy, *Natural Gas Timeline*, http://www.centreforenergy.com/AboutEnergy/ONG/NaturalGas/History.asp

### 4.3.2 Forecasts

Figure 4.14 represents CERI's view of conventional gas resource developments broken down into forecasted new gas well connections and associated non-productive wells that are a typically part of the exploration and development activities. The latter are labeled dead and abandoned wells. This figure also indicates the resulting incremental gas flow rate from the completed gas wells.

**Figure 4.14**
**Well Drilling Profile and Incremental Flow Rate in Alberta (25-Year Forecast)**




### 4.3.3 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 4.4 and 4.5, 86 percent of the impacts are directly related to Alberta, with the remaining 14 percent being felt across the other provinces and territories.

**Table 4.4**
**Impacts Associated with Investment in Alberta**

| | $ million | Thousand Person Years | | $ million | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 450,118 | 2,306 | 74,551 | 47,470 | 27,081 |
| **British Columbia** | 22,367 | 259 | 6,117 | 3,148 | 2,969 |
| **Manitoba** | 2,884 | 54 | 920 | 439 | 481 |
| **New Brunswick** | 641 | 13 | 222 | 110 | 112 |
| **Newfoundland & Labrador** | 583 | 12 | 180 | 77 | 103 |
| **Northwest Territories** | 696 | 5 | 176 | 118 | 58 |
| **Nova Scotia** | 1,282 | 21 | 453 | 212 | 241 |
| **Nunavut** | 96 | 2 | 49 | 37 | 11 |
| **Ontario** | 28,800 | 412 | 7,459 | 3,661 | 3,797 |
| **Prince Edward Island** | 131 | 3 | 53 | 25 | 28 |
| **Quebec** | 6,295 | 105 | 1,951 | 842 | 1,109 |
| **Saskatchewan** | 12,068 | 130 | 3,203 | 1,574 | 1,629 |
| **Yukon Territory** | 116 | 2 | 52 | 36 | 16 |
| **Canada** | 526,075 | 3,322 | 95,386 | 57,750 | 37,636 |

**Table 4.5**
**Impacts Associated with Operation in Alberta**

| | $ million | Thousand Person Years | | $ million | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 295,882 | 1,516 | 49,006 | 31,204 | 17,802 |
| **British Columbia** | 14,703 | 170 | 4,021 | 2,069 | 1,952 |
| **Manitoba** | 1,896 | 36 | 605 | 289 | 316 |
| **New Brunswick** | 421 | 8 | 146 | 72 | 73 |
| **Newfoundland & Labrador** | 383 | 8 | 119 | 51 | 68 |
| **Northwest Territories** | 458 | 4 | 116 | 78 | 38 |
| **Nova Scotia** | 843 | 14 | 298 | 140 | 158 |
| **Nunavut** | 63 | 1 | 32 | 25 | 7 |
| **Ontario** | 18,931 | 271 | 4,903 | 2,407 | 2,496 |
| **Prince Edward Island** | 86 | 2 | 35 | 17 | 18 |
| **Quebec** | 4,138 | 69 | 1,282 | 553 | 729 |
| **Saskatchewan** | 7,933 | 85 | 2,106 | 1,035 | 1,071 |
| **Yukon Territory** | 76 | 1 | 34 | 24 | 11 |
| **Canada** | 345,812 | 2,183 | 62,701 | 37,962 | 24,740 |

In addition to the economic impacts listed in the previous tables, the royalties payable to the province of Alberta in regard to Alberta conventional gas, over the next 25-years, will be $99,966 million. On average, this equates to approximately $4 billion per year.

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 4.15, Ontario receives 38 percent of the impacts, 29 percent for British Columbia, 16 percent for Saskatchewan and 8 percent for Quebec. Figures 4.16 and 4.17 show the similar impacts on employment, and federal and provincial taxes.

**Figure 4.15**
**Total GDP Impacts ($million)**

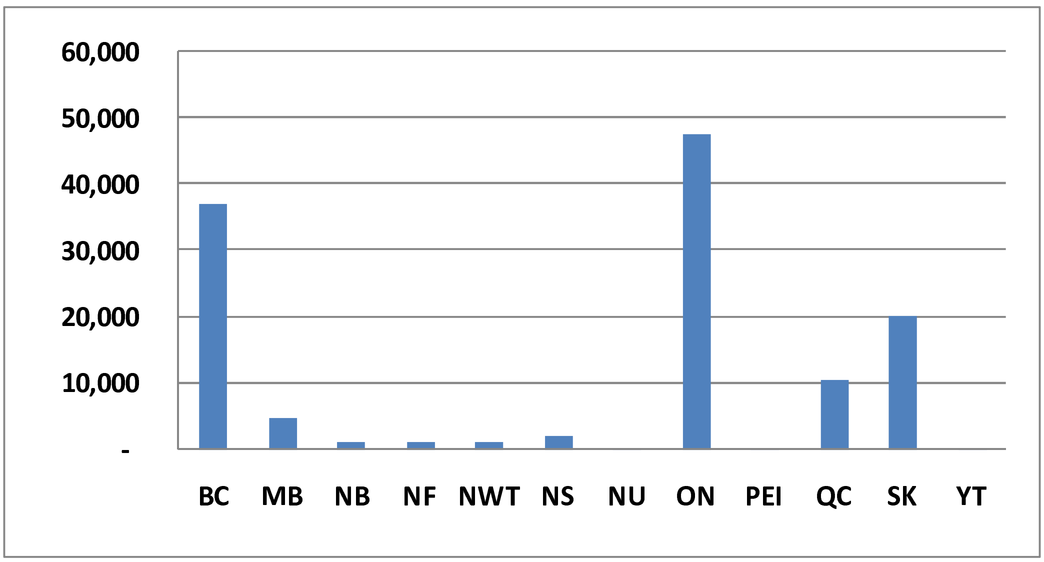


**Figure 4.16**
**Total Employment Impacts (thousand person years)**

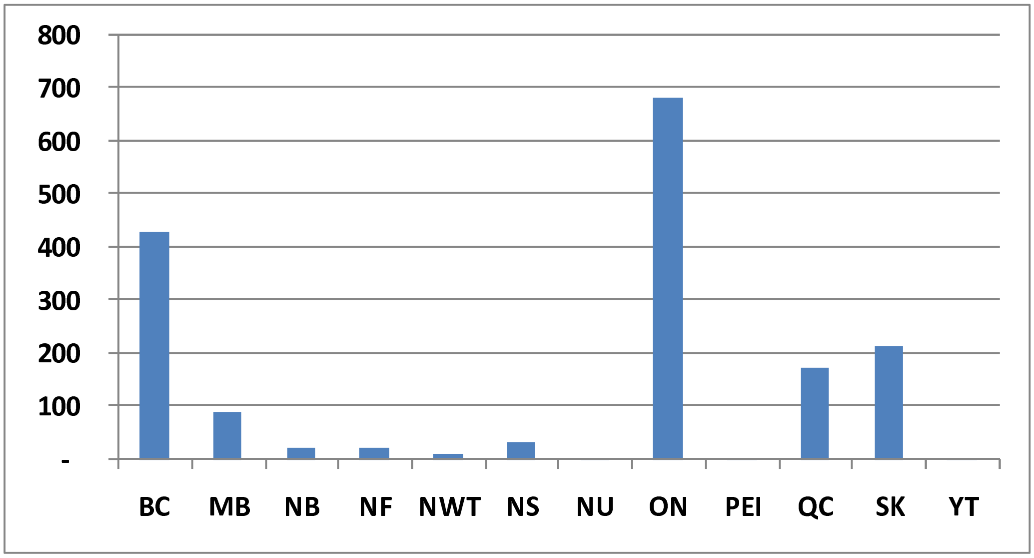
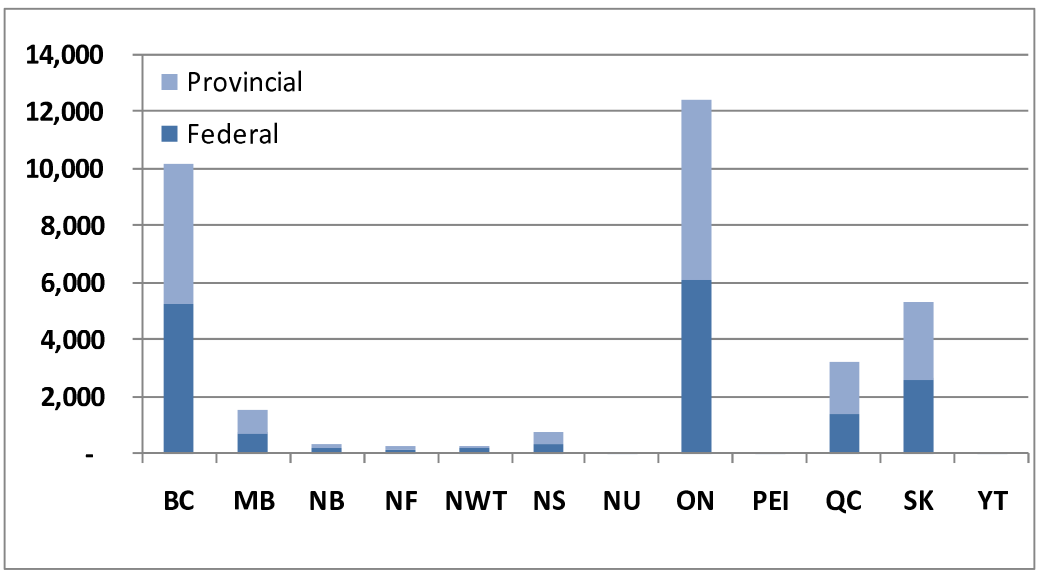



**Figure 4.17**
**Total Federal and Provincial Tax Impacts ($million)**




## 4.4 Coalbed Methane (CBM) Resources

The following section presents a background on CBM resources in Alberta, including an overview of coal geology and brief review of description of the geology of the coal seams of the Plains region of Alberta. As with previous sections, the remainder of this section reviews forecasts as well as the economic impacts of this particular resource to the province and the rest of Canada's provinces.

### 4.4.1 Background

4.4.1.1 Coal Geology Background

Coal is an organic-rich rock derived primarily from plant material that underwent burial and compaction, resulting in progressive physical and chemical changes in the original plant material. With increasing depth of burial, plant material progressively loses moisture and volatile matter while increasing carbon content and reflectance properties (see Table 4.6). This process, referred to as coalification, generates gaseous hydrocarbons, composed mainly of methane. This gas is stored in the coal as an adsorbed component within the coal matrix and, to a lesser extent, as a free gas within the pore structure of the matrix.

Coal rank indicates the maturity level of a coal, which is the degree of chemical and physical alteration to which the plant matter has been subjected. As illustrated in Table 4.6, coal rank ranges from peat through lignite, sub-bituminous, high-, medium- and low-volatile bituminous to anthracite. Coal rank, temperature and pressure are important factors in determining the capacity of coal to adsorb gas.

**Table 4.6**
**Coal Rank Properties (approximate values, %)**

| Rank | Reflectance | Volatile Matter | Carbon Content | Moisture |
|---|---|---|---|---|
| Peat | 0.3 | 64 | 60 | 75 |
| Lignite | 0.3 | 63-53 | 60-68 | 75-30 |
| Sub-bituminous | 0.4-0.6 | 53-43 | 68-75 | 30-20 |
| High-volatile bituminous | 0.5-1.1 | 45-32 | 73-85 | 25-8 |
| Medium-volatile bituminous | 1.1-1.5 | 32-23 | 85-88 | 10-8 |
| Low-volatile bituminous | 1.5-1.9 | 23-14 | 88-89 | 10-8 |
| Semi-anthracite | 1.9-2.8 | 14-8 | 89-91 | 10-8 |
| Anthracite | >2.8 | <8 | >91 | 10-8 |

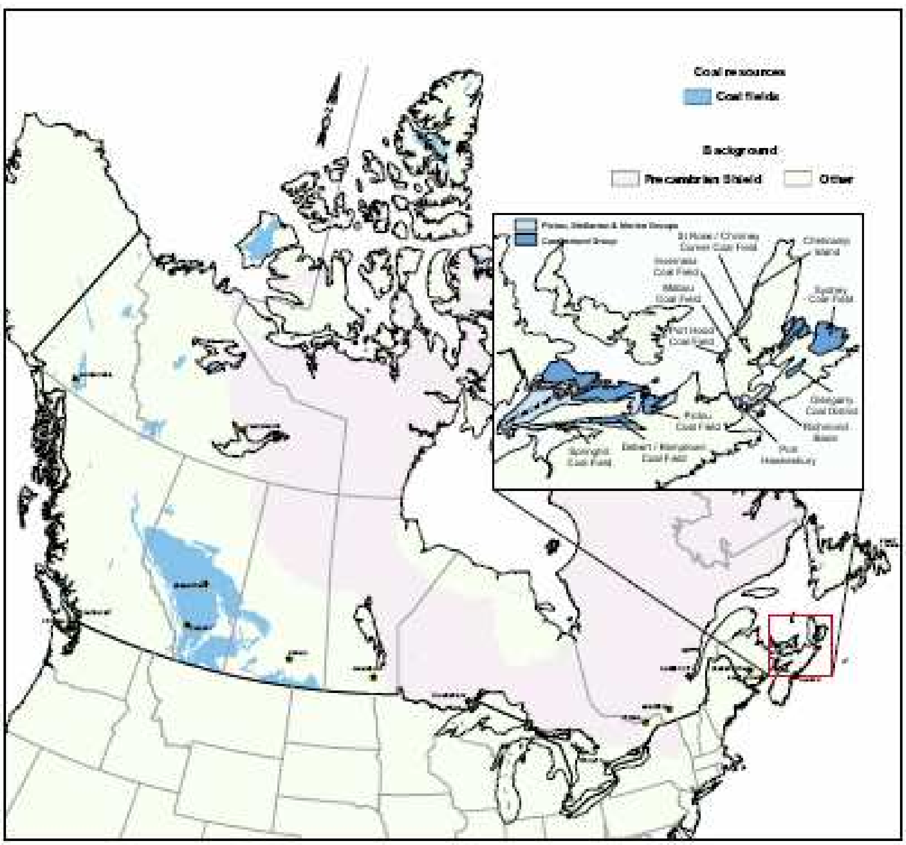
The gas content of coal generally increases with its maturity level and peaks in coals of high-volatile bituminous rank. Anthracite contains little methane. Coals above sub-bituminous rank contain methane produced primarily by thermal processes, whereas coals of sub-bituminous and lower rank contain methane produced primarily by bacterial and biogenic processes. The amount of gas that a coal of a given rank can hold is also a function of coal seam pressure.

The permeability of a coal seam is related to the degree of fracturing or cleat of the seam. Cleats or fractures in a coal seam are developed during burial, tectonic deformation and subsequent uplift. They form the primary pathways for adsorbed gas to migrate to a production well. Cleats occur in coals of all ranks but are best developed in high-volatile coals. Cleat spacing decreases in higher rank coals and is greatest in low-rank coals. Permeability of coal seams generally decreases with depth, due to the overburden pressure, which compresses the coal.

4.4.1.2 Coal of the Alberta Plains Region

Coal deposits with the potential for CBM production are widespread in Canada, occurring in the coastal, foothills and mountain regions of British Columbia, the foothills and plains regions of Alberta and in Nova Scotia. This is illustrated by Figure 4.18. While pilot projects to assess the production potential of CBM in Canada have been conducted in these areas since the beginning of the 1980s, commercial production is developing rapidly in the Plains Region of Alberta, from a few test wells in 2001 to over 10,000 wells in 2008.

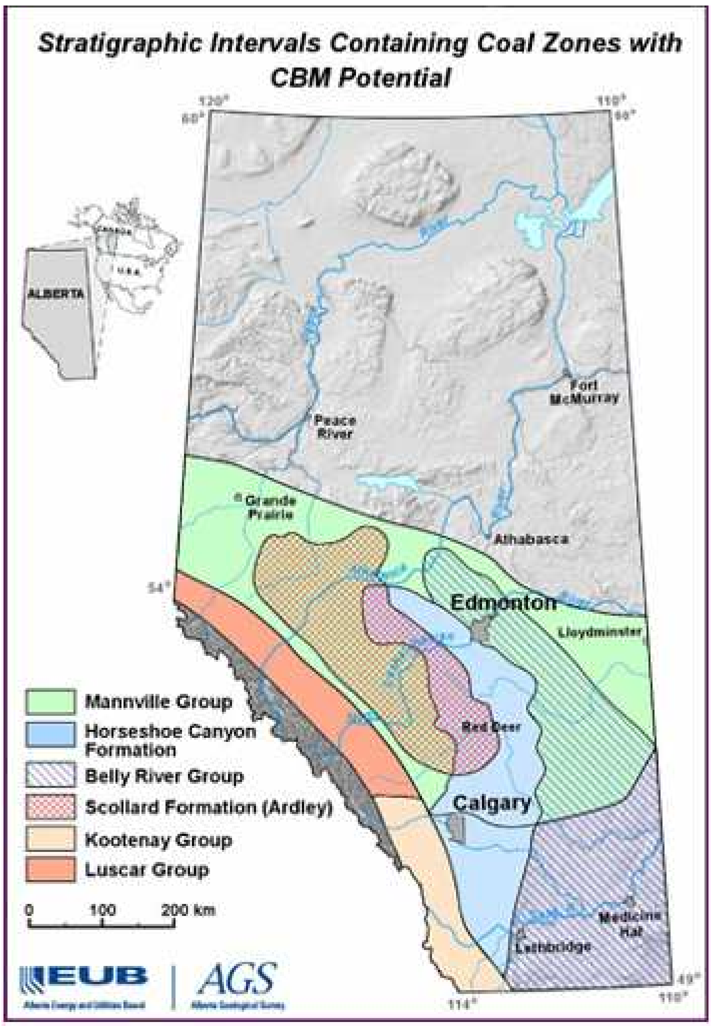
**Figure 4.18**
**Surface Distribution of Coal Bearing Sediments in Canada**



Source: Canadian Gas Potential Committee, 2001.

This section discusses in greater detail the coal bearing formations of the Alberta Plains region: Horseshoe Canyon, Mannville, the Scollard (Ardley) and Belly River formations. Figure 4.19 illustrates the surface locations of the coal bearing formations in Alberta. The figure shows that the coal zones of Alberta are extensive and widely distributed, extending from the US border in the south to Athabasca and beyond Grande Prairie in the north. Most of the coal zones in Alberta have potential as CBM targets.

**Figure 4.19**
**Coal Zones of Alberta (Surface Location)**



A 2002 estimate by the Alberta Geological Survey (AGS) of the CBM in place in the Plains region of Alberta amounts to 505 Tcf. The breakdown of this estimate by formation is: Ardley (53 Tcf), Horseshoe Canyon (66 Tcf), Belly River (66 Tcf) and Mannville (320 Tcf).

The following sub-sections discuss the two prominent coal-bearing coal formations of the Alberta Plains in greater detail, the Horseshoe Canyon Formation and the Mannville. Horseshoe Canyon coals, being relatively shallow, have relatively low gas contents but favourable cleats have made them a target for CBM exploration and production. Mannville coals, being deeper, have higher gas concentrations and, although deeper, also show potentially favourable cleats.

<u>Horseshoe Canyon Formation</u>

The Horseshoe Canyon formation contains three coal zones: the Drumheller, the Daly-Weaver and the Carbon-Thompson. Individual coal seams of the Horseshoe Canyon range from less than one to five metres thick and are generally discontinuous.

The Drumheller coal zone has been a primary target for industry and is located in the lower part of the Horseshoe Canyon formation, overlain by the Daly-Weaver and Carbon-Thompson zones. Net pays up to 20 metres occur in the upper part of the Drumheller with individual coal seams up to 5 metres thick and can be relatively shallow (about 300 metres). The zone may contain 20 or more individual thin seams with interbedded sandstone and shale, which combine to make an attractive multi-completion CBM target. The coal seams of the Daly-Weaver and Carbon-Thompson zones are thin and discontinuous.

Estimates of resources for the Drumheller zone can exceed 3 bcf per section but the Carbon-Thompson and the Daly-Thompson coal zones are generally lower (<1 bcf/section). The shallow strata in southern Alberta are under-pressured relative to hydrostatic pressure. Low formation pressures translate into lower gas retention.

Coal rank in the Horseshoe Canyon formation ranges from sub-bituminous to high-volatile bituminous. The Drumheller coal zone ranges from sub-bituminous at shallow depths in the southeast, increasing westward and northward to high-volatile bituminous. Carbon-Thompson and Daly-Weaver coals are generally within the high-volatile bituminous rank range.

Permeability data are limited for the Horseshoe Canyon formation, and were initially thought to be unfavourable for CBM production. However, recent commercial CBM activity has prompted many to rethink the viability of Horseshoe Canyon coals.

<u>Mannville</u>

The Lower Cretaceous Mannville group coals are the oldest and deepest coals of the Alberta Plains and occur throughout the three stratigraphic units of the group – the Lower, Middle, and Upper units. The Mannville coals are widely distributed across the Alberta Plains and thicken from east to west with the thickest coals generally occurring in the Upper Mannville unit. Typically six or seven seams with net coal thickness ranging from 2 to 14 metres occur over a stratigraphic interval of 40 to 100 metres at depths ranging from about 800 metres up to 2,800 metres. While thickness is extremely variable in coals in northeastern Alberta, they are typically thinner and shallower than in central Alberta.

Coals in the Gething formation (Lower Mannville equivalent), located in west-central Alberta and northeast British Columbia, are an important coal-bearing unit. While the coals at the western edge of the Gething may reach a thickness of 18 metres, the average net coal accumulation in western Alberta is only two to four metres. These coals are laterally discontinuous and seams tend to be less than three metres thick. Gething seams range from 0.2 to two metres thick.

Coal rank of Mannville coals of the Alberta Plains ranges from sub-bituminous to high-volatile bituminous in the north and east, with rank increasing westward. Mannville coals at the western edge of the deep basin, range from medium- to low-volatile bituminous. Gething coals range in rank from high-volatile bituminous to semi-anthracite. Estimates of gas-in-place for Mannville coals range up to 10 bcf per section.

Although data are limited, the permeability of Mannville coals is considered to be low. For the central Plains, reported permeability is in the range of 0.1 to 0.2 millidarcies. However, recent tests of Mannville coals in the central Plains report a higher permeability, in the order of three to five millidarcies.

### 4.4.2 Forecasts

Figures 4.20 and 4.21 represents CERI's view of CBM gas resource developments broken down into forecasted new CBM well connections and associated non-productive wells that are a typically part of the exploration and development activities. The latter are labeled dead and abandoned wells. These figures also indicate the resulting incremental gas flow rate from the completed CBM wells. Figure 4.20 illustrates cumulative investment and incremental flow rates for the Horseshoe Canyon while Figure 4.21 pertains to the Mannville.

**Figure 4.20**
**Cumulative Investment and Incremental Flow Rate for the Horseshoe Canyon (25-Year Forecast)**

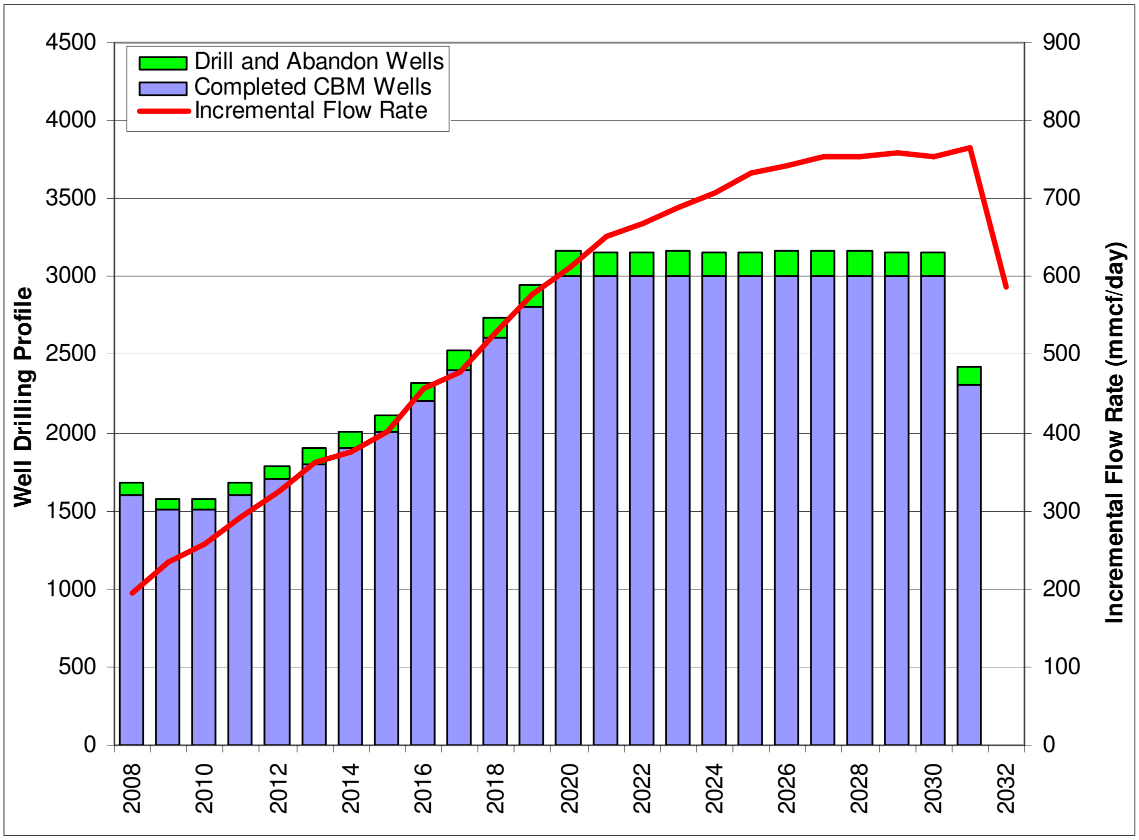
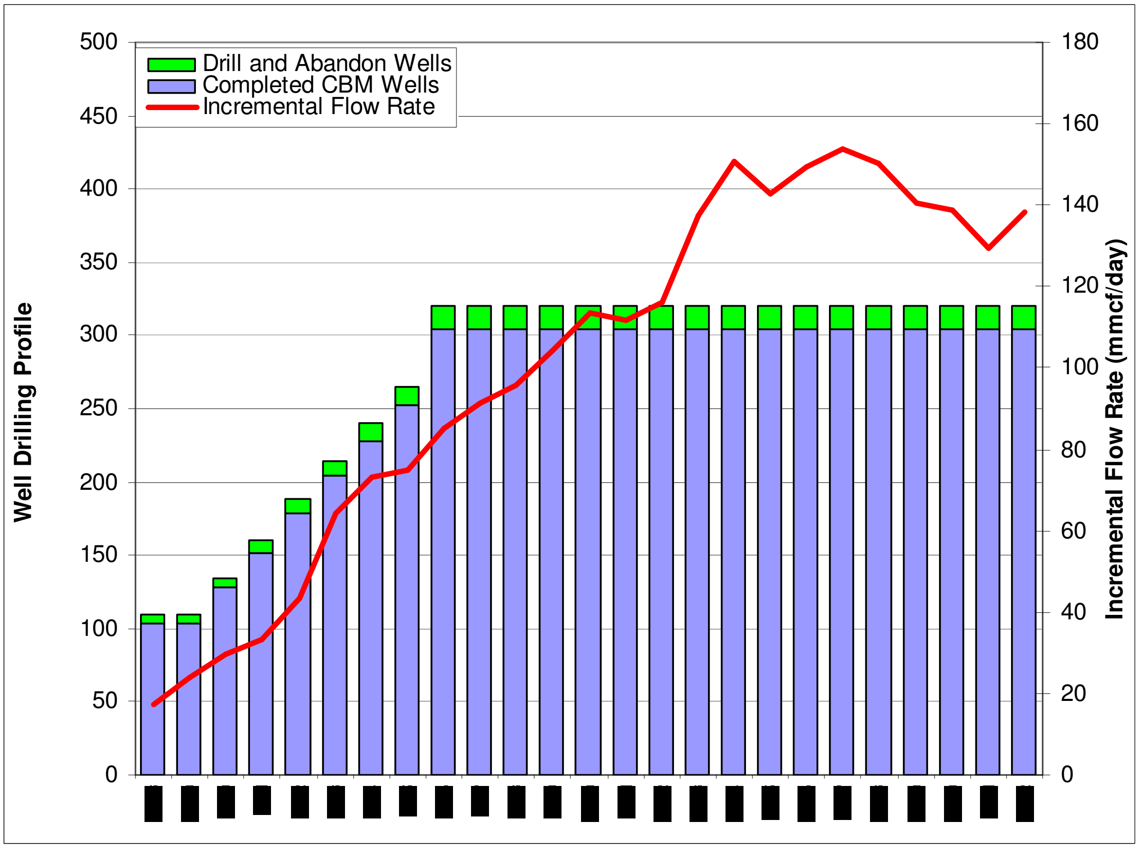


**Figure 4.21**
**Cumulative Investment and Incremental Flow Rate for the Mannville (25-Year Forecast)**




### 4.4.3 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 4.7 and 4.8, 86 percent of the impacts are directly related to Alberta, with the remaining 14 percent being felt across the other provinces and territories.

**Table 4.7**
**Impacts Associated with Investment in Alberta**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 56,607 | 290 | 9,376 | 5,970 | 3,406 |
| **British Columbia** | 2,813 | 33 | 769 | 396 | 373 |
| **Manitoba** | 363 | 7 | 116 | 55 | 60 |
| **New Brunswick** | 81 | 2 | 28 | 14 | 14 |
| **Newfoundland & Labrador** | 73 | 2 | 23 | 10 | 13 |
| **Northwest Territories** | 88 | 1 | 22 | 15 | 7 |
| **Nova Scotia** | 161 | 3 | 57 | 27 | 30 |
| **Nunavut** | 12 | 0 | 6 | 5 | 1 |
| **Ontario** | 3,622 | 52 | 938 | 460 | 478 |
| **Prince Edward Island** | 16 | 0 | 7 | 3 | 3 |
| **Quebec** | 792 | 13 | 245 | 106 | 139 |
| **Saskatchewan** | 1,518 | 16 | 403 | 198 | 205 |
| **Yukon Territory** | 15 | 0 | 7 | 5 | 2 |
| **Canada** | 66,159 | 418 | 11,996 | 7,263 | 4,733 |

**Table 4.8**
**Impacts Associated with Operation in Alberta**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 41,844 | 214 | 6,930 | 4,413 | 2,518 |
| **British Columbia** | 2,079 | 24 | 569 | 293 | 276 |
| **Manitoba** | 268 | 5 | 86 | 41 | 45 |
| **New Brunswick** | 60 | 1 | 21 | 10 | 10 |
| **Newfoundland & Labrador** | 54 | 1 | 17 | 7 | 10 |
| **Northwest Territories** | 65 | 0 | 16 | 11 | 5 |
| **Nova Scotia** | 119 | 2 | 42 | 20 | 22 |
| **Nunavut** | 9 | 0 | 5 | 3 | 1 |
| **Ontario** | 2,677 | 38 | 693 | 340 | 353 |
| **Prince Edward Island** | 12 | 0 | 5 | 2 | 3 |
| **Quebec** | 585 | 10 | 181 | 78 | 103 |
| **Saskatchewan** | 1,122 | 12 | 298 | 146 | 151 |
| **Yukon Territory** | 11 | 0 | 5 | 3 | 2 |
| **Canada** | 48,905 | 309 | 8,867 | 5,369 | 3,499 |

In addition to the economic impacts listed in the previous tables, the royalties payable to the province of Alberta in regard to Alberta CBM gas from Horseshoe Canyon and Mannville, over the next 25-years, will be $5,563 million and $1,597 million, respectively. On average, this equates to approximately $286 million per year.

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 4.22, Ontario receives 38 percent of the impacts, 29 percent for British Columbia, 16 percent for Saskatchewan and 8 percent for Quebec. Figures 4.23 and 4.24 show the similar impacts on employment, and federal and provincial taxes.

**Figure 4.22**
**Total GDP Impacts ($million)**

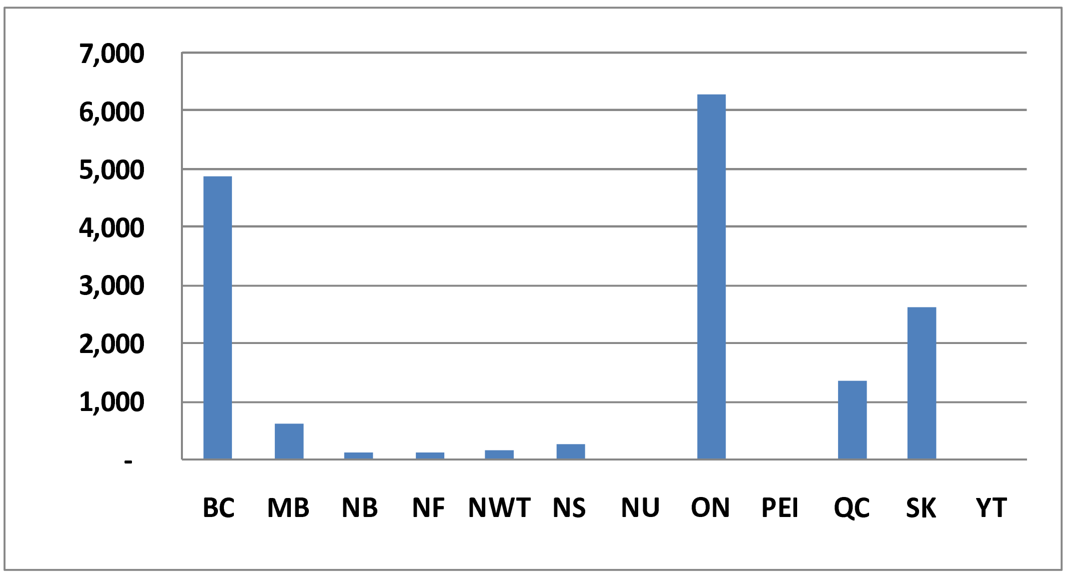


**Figure 4.23**
**Total Employment Impacts (thousand person years)**

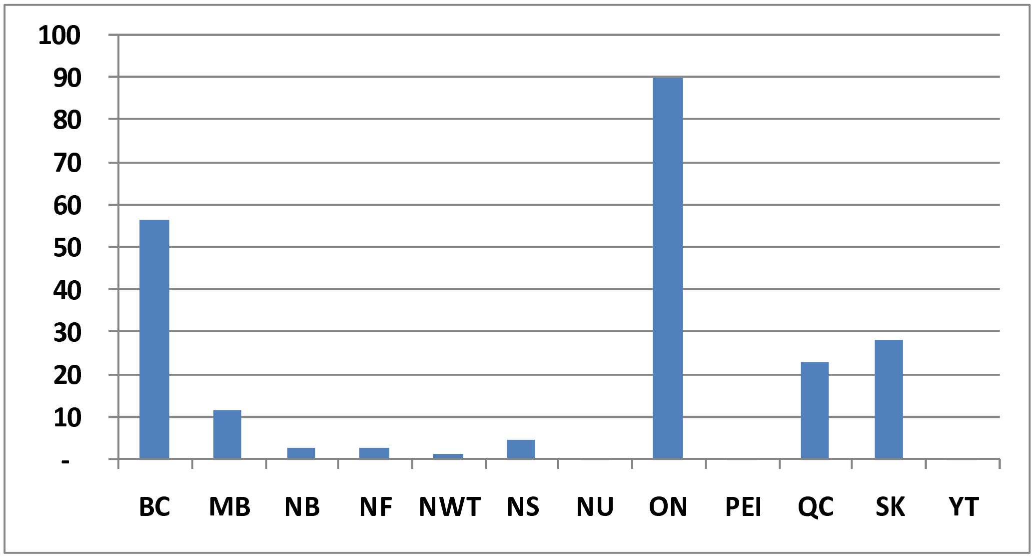
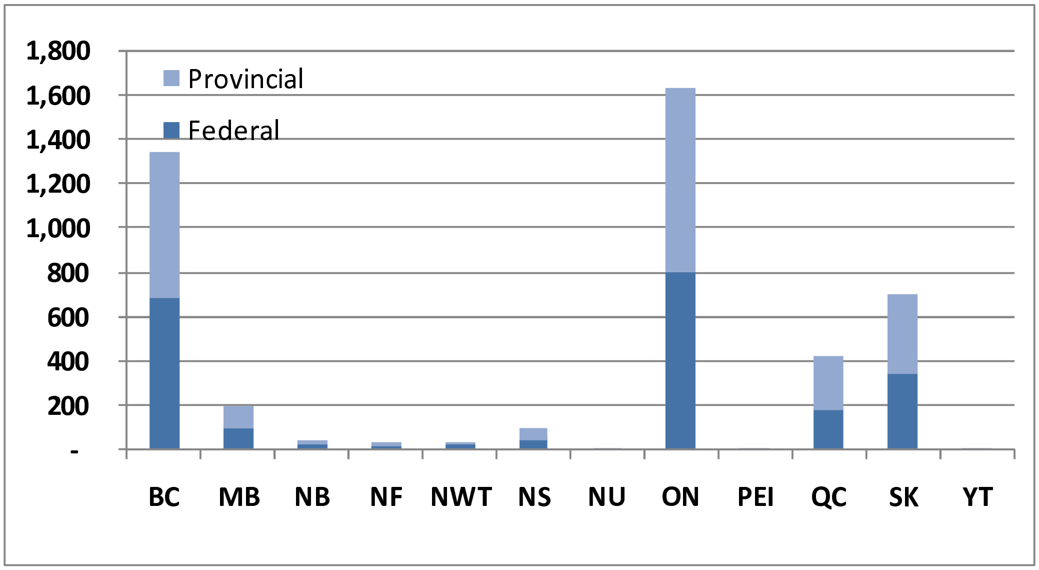



**Figure 4.24**
**Total Federal and Provincial Tax Impacts ($million)**

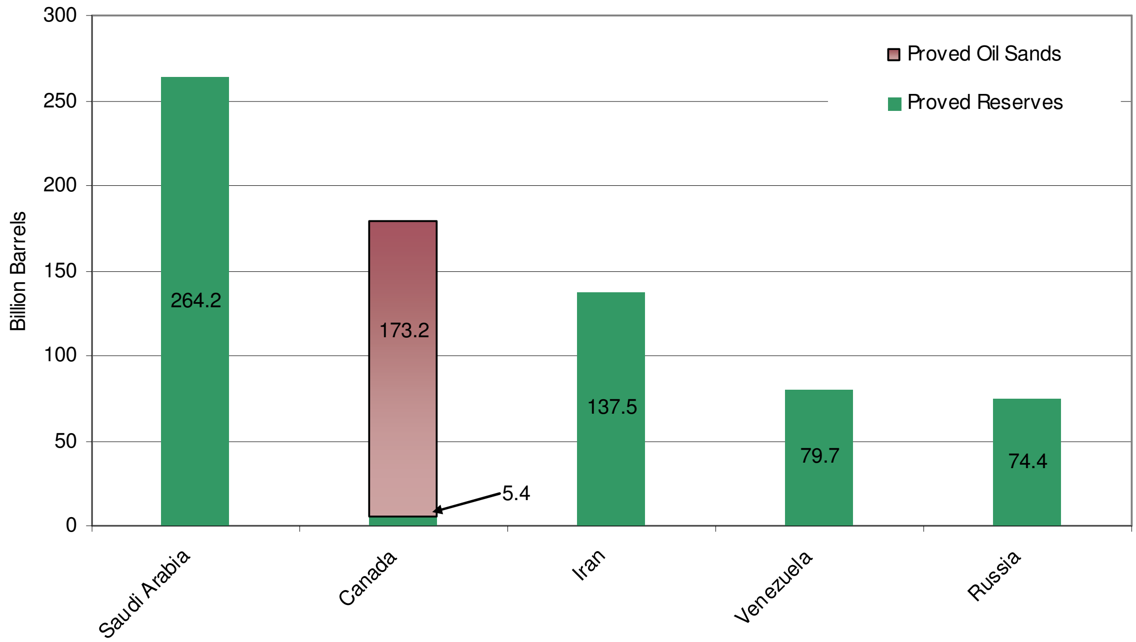



## 4.5 Oil Sands Resources

### 4.5.1 Background

As reserves and production of conventional crude oil decline, unconventional resources have moved to center stage in Canada, and are becoming increasingly important to the global oil industry. With an estimated initial volume in-place of approximately 1.7 trillion barrels (269 billion $m^3$) of crude bitumen, Alberta's oil sands are one of the largest hydrocarbon deposits in the world.[21] While not quite matching Saudi Arabia's conventional oil reserves, the enormous remaining established reserves of Canada's crude bitumen places Canada in the top tier of the world's oil reserves (see Figure 4.25)[22], cutting the Organization of Petroleum Exporting Countries' (OPEC's) share of world oil reserves by more than 10 percent.

**Figure 4.25**
**Top Five World Proven Reserves**




SOURCES: (1) Statistical Series 2003-98, Alberta's Reserves 2005 and Supply/Demand Outlook 2006-2015, (AEUB); and (2) BP Statistical Review of World Energy 2006.

Located in northern Alberta in the Western Canada Sedimentary Basin (WCSB), Alberta's oil sands resources are spread across more than 140,000 square kilometers (see Figure 4.26).[23] They are primarily contained in sand and carbonate formations that are located in the following areas:

- Athabasca in the northeast;
- Cold Lake in the east-central; and
- Peace River in the northwest parts of the province.

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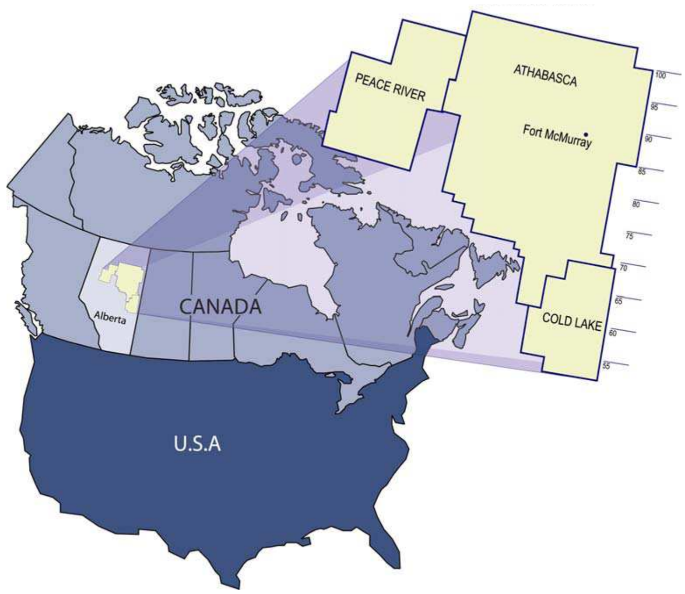
[21]Alberta Energy and Utilities Board, *Alberta's Reserves 2005 and Supply/Demand Outlook 2006 – 2015,* http://www.eub.gov.ab.ca/bbs/products/STs/st98_current.pdf, June 2006.

[22]The BP Group, *BP Statistical Review of World Energy 2003*, www.bp.com. Saudi Arabia's proved oil reserves at the end of 2002 stood at 261.8 billion barrels. Proved reserves are generally taken to be those quantities that geological and engineering information indicates can be recovered in the future from known reservoirs under existing economic and operating conditions with reasonable certainty.

[23] Oil sands deposits also exist in Saskatchewan.

**Figure 4.26**
**Oil Sands Areas in Alberta**




SOURCE: Alberta Department of Energy.

Oil sands are composed of approximately 80 to 85 percent sand, clay and other mineral matter, 5 to 10 weight percent water, and anywhere from 1 to 18 weight percent crude bitumen. Bitumen content greater than 12 percent is considered rich, while anything less than 6 percent is poor and not usually considered economically feasible to develop.

In the Athabasca region, the oil sands are hydrophilic or "water wet". A thin film of water, which is surrounded by crude bitumen, envelops each grain of sand. The sands are unconsolidated with grain-to-grain contact. Being silica quartz, the sands are extremely abrasive, thus posing significant challenges in the mining and extraction processes. Early developers of the oil sands experienced the challenges associated with this abrasive product, damaging pipelines and equipment. This resulted in alternative methods to transport the bitumen in pipelines, such as creating bitumen emulsions and adding large quantities of water into pipelines for hydro transport. These and other innovative initiatives helped turn the resource into a viable source of oil.

Crude bitumen is a thick, viscous crude oil that, at room temperature, is in a near solid state. The definition used in the industry is that crude bitumen is "a naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulphur compounds and that, in its naturally occurring viscous state, will not flow to a well".[24]

[24]Alberta, Canada, *Oil Sands Conservation Act, Section 1(1)(c)*, Alberta Statutes and Regulations. Note that more than 100 thousand b/d (16,000 $m^3$/d) of crude bitumen from the Cold Lake and Athabasca Oil Sands Areas was produced using primary production techniques during 2002, in apparent contravention of this definition.

The term crude bitumen generally refers to petroleum with a density greater than 960 kilograms per cubic meter.[25] In fact, much of the bitumen in Canada's oil sands deposits has densities that exceed 1,000 kg/m$^3$ (API Gravity of less than 10 degrees). Because of its high gravity and high viscosity characteristics, crude bitumen may be blended with a light hydrocarbon liquid (condensate) before it is shipped to markets by pipeline.

Table 4.9 compares the densities of a number of crude oil types, including blended bitumen from Athabasca and Cold Lake.

**Table 4.9**
**Crude Oil Densities (kg/m3)**

| Crude Oil Type | Density |
|---|---|
| Athabasca Crude Bitumen | 1,015 |
| Cold Lake Crude Bitumen | 1,009 |
| Maya | 921 |
| Athabasca Bitumen Blend | 919[a] |
| Cold Lake Bitumen Blend | 919[a] |
| Bow River Blend | 894 |
| Arab Light | 858 |
| Bonny Light | 841 |
| West Texas Intermediate | 827 |
| Federated Light | 826 |
| Commercial Condensate | 720 |

[a]Athabasca and Cold Lake Bitumen Blends are derived by adding diluent to crude bitumen to reduce viscosity prior to being transported by pipeline. The most commonly used diluent is very light natural gas liquid (C5+ or pentanes plus), which is a by-product of natural gas processing. A condensate diluent typically constitutes 24-32 percent of the bitumen blend.

SOURCES: (1) *Markets for Canadian Bitumen-Based Feedstock*, CERI Study No. 101; and (2) Alberta Research Council Open File Report 1993-25.

### 4.5.2 Crude Bitumen Reserves

The Alberta Energy and Utilities Board estimates the initial volume of crude bitumen in-place to be 270.3 billion m$^3$ (1,701 billion barrels) as of December 31, 2006. The Athabasca region alone accounts for almost 80 percent or 217.7 billion m$^3$ (1,369 billion barrels) of the total.

Table 4.10 summarizes the volumetric resources by oil sands area (OSAs) and oil sands deposit (OSDs). OSAs define the geographical boundaries of crude bitumen occurrence, while OSDs contain the specific geological zones declared as oil sands deposits. Both, OSAs and OSDs are designated by the ERCB.

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[25] Alberta Department of Energy, http://www.energy.gov.ab.ca/OilSands/793.asp, February 2008.

**Table 4.10**
**Initial In-Place Volumes of Crude Bitumen**

| Oil Sands Area<br>Oil Sands Deposit | Initial Volume In-Place ($10^6 m^3$) | Average Pay Thickness (m) | Average Bitumen Saturation (%) Mass | Pore Volume | Average Porosity |
|---|---|---|---|---|---|
| **Athabasca** | | | | | |
| Grand Rapids | 8,678 | 7.2 | 6.3 | 56 | 30 |
| Wabiskaw-McMurray (mineable) | 16,087 | 30.5 | 9.7 | 69 | 30 |
| Wabiskaw-McMurray (in situ) | 132,128 | 13.2 | 10.2 | 73 | 29 |
| Nisku | 10,330 | 8.0 | 5.7 | 63 | 21 |
| Grosmont | 50,500 | 10.4 | 4.7 | 68 | 16 |
| Sub-Total | 217,723 | | | | |
| **Cold Lake** | | | | | |
| Grand Rapids | 17,304 | 5.9 | 9.5 | 66 | 31 |
| Clearwater | 9,422 | 11.8 | 8.9 | 59 | 31 |
| Wabiskaw-McMurray | 4,287 | 5.4 | 7.3 | 59 | 27 |
| Sub-Total | 31,013 | | | | |
| **Peace River** | | | | | |
| Bluesky-Gething | 10,968 | 6.1 | 8.1 | 68 | 26 |
| Belloy | 282 | 8.0 | 7.8 | 64 | 27 |
| Debolt | 7,800 | 23.7 | 5.1 | 65 | 18 |
| Shunda | 2,510 | 14.0 | 5.3 | 52 | 23 |
| Sub-Total | 21,560 | | | | |
| **Total** | 270,296 | | | | |

SOURCE: Alberta Energy and Utilities Board, Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007 – 2016, June 2007, http://www.eub.gov.ab.ca/bbs/products/STs/st98_current.pdf

As of December 31, 2006, remaining established reserves were estimated by the EUB to be 27.53 billion $m^3$ (173.2 billion barrels). Remaining established reserves are calculated separately for those that are likely to be recovered by mining methods and those by in situ methods using established technology and under anticipated economic conditions.

Bitumen from the shallower oil sands deposits is extracted through open-pit mining operations. These mines expose the oil sands by stripping the overburden. The oil sand is then removed by using truck and shovel mining methods. Bitumen is separated from the sand through a process of adding warm water and agitation. Roughly two tons of sand are mined, moved and processed to produce one barrel of bitumen.

In situ, on the other hand, means "in-place", and indicates that the bitumen is extracted from the sand in the reservoir. These techniques are employed for deeper oil sands deposits (generally greater than about 75m to the top of the oil sands formation). The two main in situ processes currently being used are cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD). These methods inject steam into the formation to heat the bitumen, allowing it to flow and be pumped to the surface.

The EUB determined mineable established reserves by identifying potential mineable areas using economic strip ratio (ESR) criteria, a minimum saturation cutoff of 7 weight percent, and a minimum saturated zone thickness cutoff of 3.0 metres. The ESR criteria are fully explained in *ERCB Report 79-H, Appendix 3.*[26]

The EUB determined in situ established reserves for those areas considered amenable to in situ recovery methods. Reserves attributable to thermal development were determined using a minimum saturation cutoff of three weight percent crude bitumen and a minimum zone thickness of ten metres. For primary development, the same saturation cutoff of three weight percent was used, with a minimum zone thickness of three metres. Recovery factors of twenty percent for thermal development and five percent for primary development were applied to the areas within the cutoffs. The recovery factor for future thermal development is assumed to be lower than recoveries being achieved by some of the active in situ projects. This is to account for the uncertainty in the future recovery processes and the uncertainties inherent with developing poorer quality resource areas (areas under active development are of higher quality than future areas). While the resource base is very large, it is worth noting that many in situ recovery technologies are still in the early development stage and there is still considerable uncertainty about how much crude bitumen will ultimately be recovered.

Table 4.11 summarizes the EUB's estimates of in-place volumes and established mineable and in situ crude bitumen reserves.[27]

[26]Alberta Canada, Alberta Energy Resources Conservation Board, *Alsands Fort McMurray Project, ERCB Report 79-H,* 1979.
[27]Alberta, Canada, Alberta Energy and Utilities Board, *EUB Statistical Series 2007-98: Alberta's Reserves 2006 and Supply Demand Outlook 2007-2016* (Calgary, Alberta, 2007), http://www.eub.gov.ab.ca/bbs/products/STs/st98_current.pdf.

**Table 4.11**
**In-Place Volumes and Established Reserves of Crude Bitumen ($10^9 m^3$ as of December 31, 2006)**

| Recovery Method | Initial Volume In-Place | Initial Established Reserves | Cumulative Production | Remaining Established Reserves | Remaining Established Reserves Under Active Development |
|---|---|---|---|---|---|
| Mineable | 16.1 | 5.59 | 0.58 | 5.01 | 2.95 |
| In situ | 254.2 | 22.80 | 0.28 | 22.53 | 0.39 |
| Total | 270.3 | 28.39 | 0.86 | 27.53 | 3.34 |
| | (1,701)[a] | (178.7)[a] | (5.4)[a] | (173.2)[a] | (21.0)[a] |

[a] Imperial equivalent in billions of stock-tank barrels.

SOURCE: Alberta Energy and Utilities Board, *Statistical Series 2007-98, Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007-2016*.

Of the remaining established reserves of 27.53 billion $m^3$, 3.34 billion $m^3$ (21.0 billion barrels), or 12.13 percent, were under active development at year-end 2006. Significantly, more than 80 percent of remaining established reserves are estimated to be recoverable from in situ techniques.[28]

### 4.5.3 Mineable Crude Bitumen Reserves (under active development)

Oil sands mines currently comprise operations by Suncor Energy Inc., Syncrude Canada Ltd. and Albian Sands Energy Inc. The first commercial development of Alberta's oil sands began when Great Canadian Oil Sands (now Suncor) opened its mine, extraction plant and upgrader north of Fort McMurray in 1967. This was followed by development of the Syncrude mine, extraction plant and upgrader, in the same area, in the 1970s. Construction began on the Syncrude site in 1973 and, after five years of construction, Syncrude commenced production in 1978. Albian Sands operates the Muskeg River Mine located 75 kilometers north of Fort McMurray. The project reached a major milestone with start-up and first bitumen production on December 29, 2002. Albian Sands is part of the Athabasca Oil Sands Project (AOSP), a joint venture between Shell Canada Limited (60 percent), Chevron Canada Limited (20 percent) and Marathon Oil Canada Corporation (20 percent).

The EUB publishes estimates of mineable crude bitumen reserves for each of the three operators as shown in Table 4.12.

[28] Ibid.

**Table 4.12**
**Mineable Crude Bitumen Reserves ($10^6$m3 as of December 31, 2006)**

| Development | Initial Volume In-Place | Initial Established Reserves | Cumulative Production | Remaining Established Reserves |
|---|---|---|---|---|
| Albian Sands | 672 | 419 | 32 | 387 |
| Fort Hills | 699 | 364 | 0 | 364 |
| Horizon | 834 | 537 | 0 | 537 |
| Jackpine | 361 | 222 | 0 | 222 |
| Suncor | 990 | 687 | 220 | 467 |
| Syncrude | 2,071 | 1,306 | 330 | 976 |
| Total | 5,627 | 3,535 | 582 | 2,953 |

SOURCE: Alberta Energy and Utilities Board, *Statistical Series 2007-98, Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007-2016.*

#### 4.5.4 Oil Sands Production and Investment Forecast

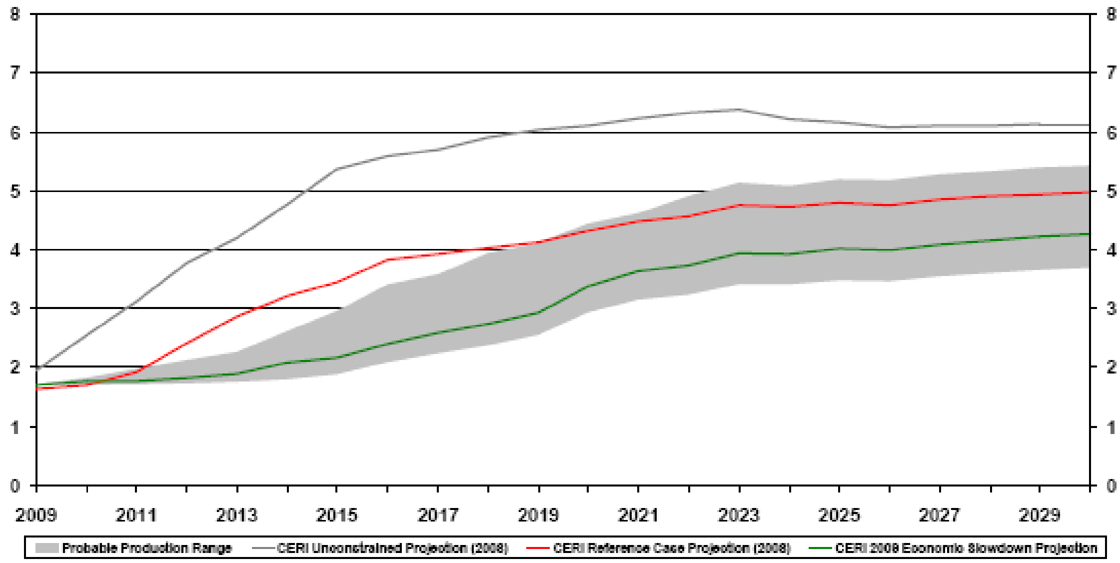
The oil sands production and investment forecast used in this study are based heavily on an oil sands briefing entitled "The Eye of the Beholder: Oil Sands Calamity or Golden Opportunity?" released by David McColl in February of this year. In late 2008, CERI released[29] updated oil sands projections[30]. The landscape has, however, dramatically changed since then; these sentiments are shared and reflected in the useful briefing released in February 2009.

Various proponents of oil sands projects have withdrawn their applications, announced delays and/or placed their proposed projects on hold until the economy rebounds and the investment can generate a reasonable rate of return. Figure 4.27 represents CERI's outlook for oil sands production.

[29] D. McColl, M. Slagorsky, "Canadian Oil Sands Supply Costs and Development Projects (2008 – 2030)", Study No. 118, November 2008: http://www.ceri.ca/#OilSandsIndustryUpdate, January 29, 2009.

[30] The values that are presented in this briefing reflect the "name plate capacity" for the oil sands and will be higher than actual production. While a facility is built for a certain capacity, it typically doesn't achieve that level of production on a constant basis. There is a litany of reasons why this is the case, and discussing it goes beyond the scope and purpose of the briefing. Actual production values are only slightly under the name plate capacity.

**Figure 4.27**
**Bitumen Production Capacity, Million Barrels per Day (mmbpd)**




In 2008, CERI was projecting a potential for oil sands production of over 5 million barrels per day (mmbpd) by 2015, and over 6 mmbpd by 2030. It was our opinion that the likely development path of the oil sands would be far lower than the CERI Unconstrained Projection (2008). The CERI Reference Case Projection (2008) indicated 3.4 mmbpd of bitumen production by 2015, increasing to 5 mmbpd by 2030. In the 2008 report, CERI provided a global slowdown case: based upon information available in late October, relating to both the global slowdown and the initial signs of an eventual slowdown in the oil sands. While these data are not presented in this report, CERI has updated the scenario and it is now presented as the "CERI 2009 Economic Slowdown Projection".

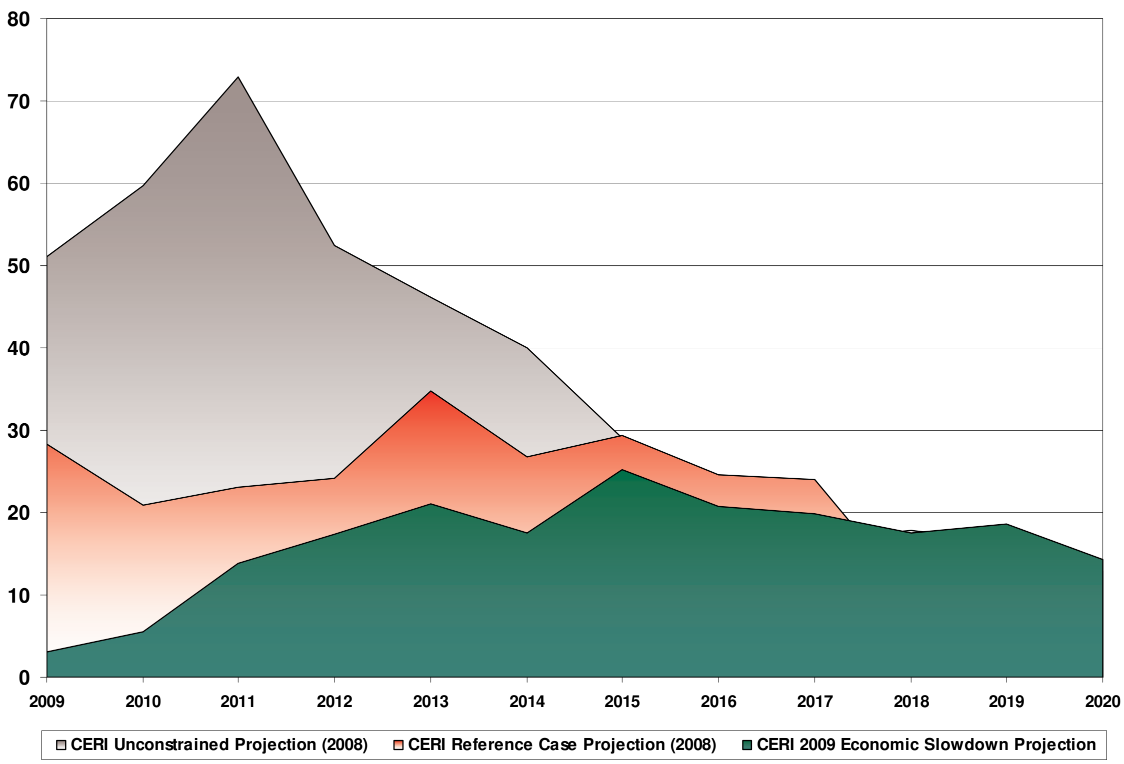
The slowdown projection reflects a scenario in which the price of oil stays below US$60 WTI / bbl for most of 2009 and the credit markets still lack liquidity. Under this projection, economic recovery begins in early 2010, as indicated by the previously provided oil price forecast, and liquidity slowly starts to return to the economy. In conjunction with the economic recovery, oil sands development stalls until 2013, with no major growth until 2015. Previously announced and approved (by government) projects remain delayed, and some remain in peril. This scenario is similar to what is currently taking place in the oil sands industry.

While the price of oil and the global economy are expected to rebound in 2010, it will take another two years before oil sands production growth resumes. CERI assumes this resumption to be limited to established oil sands projects and others with adequate financing in place prior to the credit collapse of 2008; it takes at least two years for most mining and in situ projects to start production after construction begins. However, many projects will not start construction in 2010, but will begin a reassessment and refinancing period that could take several years. Some projects are likely to be deferred until 2015, which will create a further backlog in projects, pushing those with 2015 plans (as announced in 2006 to early 2008) beyond 2020.

While CERI does not anticipate a rapid recovery and explosion in growth, as many had previously projected, we have included a margin of error in our projections, as indicated by the grey area on Figure 4.27. This reflects the Probable Production Range for oil sands development, which is highly dependent upon the recovery in the price of oil and increased liquidity in the capital markets. In 2015 the total production band is 1.9 to 2.9 mmbpd, which broadens by 2030 to 3.7 to 5.4 mmbpd.

Figure 4.28 depicts the total capital expenditure on new oil sands projects (i.e., excluding ongoing or sustaining capital) for the period 2009 to 2020.[31]

**Figure 4.28**
**Oil Sands Capital Investment (2008 Billion Canadian Dollars)**




As is apparent, capital spending peaks that were previously projected are not likely to occur over the next 11 years.[32] Oil sands spending will be modest, and at a level that CERI believes the Canadian economy can easily absorb (based upon historic oil sands spending).

[31] Upon request, annual capital spending beyond 2020 is available to organizations that purchase(d) our 2008 report.

The harsh reality is the total "loss" of investment that CERI is projecting. While part of this is a direct result of the economic slowdown, it cannot be solely attributed to the slowdown; there are other factors involved, such as labour and equipment availability. Another way to look at the "loss" is as a gain that is created by the existence and development of the oil sands. The CERI 2009 Economic Slowdown Projection indicates that $218 billion will be invested in the oil sands for new production. This is $97 billion less (the "loss") than previously projected under the CERI Reference Case Projection (2008) and a shocking $241 billion less than the CERI Unconstrained Projection (2008).

### 4.5.5 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 4.13 and 4.14, 90 percent of the impacts are directly related to Alberta, with the remaining 10 percent being felt across the other provinces and territories.

**Table 4.13**
**Impacts Associated with Investment in Alberta**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 156,395 | 1,352 | 25,903 | 16,494 | 9,410 |
| **British Columbia** | 8,631 | 138 | 2,360 | 1,215 | 1,146 |
| **Manitoba** | 2,715 | 52 | 866 | 413 | 453 |
| **New Brunswick** | 477 | 9 | 165 | 82 | 83 |
| **Newfoundland & Labrador** | 366 | 8 | 113 | 49 | 65 |
| **Northwest Territories** | 202 | 2 | 51 | 34 | 17 |
| **Nova Scotia** | 630 | 13 | 223 | 104 | 118 |
| **Nunavut** | 54 | 1 | 27 | 21 | 6 |
| **Ontario** | 11,406 | 172 | 2,954 | 1,450 | 1,504 |
| **Prince Edward Island** | 89 | 2 | 36 | 17 | 19 |
| **Quebec** | 5,221 | 84 | 1,618 | 698 | 920 |
| **Saskatchewan** | 3,552 | 56 | 943 | 463 | 479 |
| **Yukon Territory** | 64 | 1 | 29 | 20 | 9 |
| **Canada** | 189,801 | 1,889 | 35,288 | 21,060 | 14,228 |

[32] The previous peaks were over 70 billion in 2011 for the CERI Unconstrained Projection (2008), and over 40 billion in 2013 for the CERI Reference Case Projection (2008).

**Table 4.14**
**Impacts Associated with Operation in Alberta**

| | $ million GDP | Thousand Person Years Employment | $ million Total Net Tax | Federal | Provincial |
|---|---|---|---|---|---|
| **Alberta** | 1,418,135 | 7,465 | 234,881 | 149,558 | 85,322 |
| **British Columbia** | 36,843 | 575 | 10,076 | 5,185 | 4,891 |
| **Manitoba** | 8,833 | 163 | 2,818 | 1,345 | 1,473 |
| **New Brunswick** | 1,786 | 34 | 618 | 307 | 311 |
| **Newfoundland & Labrador** | 1,689 | 35 | 522 | 224 | 298 |
| **Northwest Territories** | 966 | 12 | 245 | 164 | 81 |
| **Nova Scotia** | 2,626 | 50 | 928 | 435 | 493 |
| **Nunavut** | 312 | 5 | 158 | 121 | 37 |
| **Ontario** | 43,444 | 640 | 11,251 | 5,523 | 5,728 |
| **Prince Edward Island** | 368 | 7 | 149 | 72 | 78 |
| **Quebec** | 17,951 | 292 | 5,563 | 2,400 | 3,163 |
| **Saskatchewan** | 15,142 | 246 | 4,019 | 1,975 | 2,044 |
| **Yukon Territory** | 359 | 5 | 162 | 111 | 50 |
| **Canada** | 1,548,452 | 9,530 | 271,389 | 167,420 | 103,969 |

In addition to the economic impacts listed in the previous tables, the royalties payable to the province of Alberta in regard to Alberta oil sands, over the next 25 years, will be $184,616 million. On average, this equates to approximately $7.4 billion per year. Royalties payable to the province of Alberta in regard to in situ and mining will be $94,296 million and $90,318 million, respectively.

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 4.29, Ontario receives 34 percent of the impacts, 28 percent for British Columbia, 14 percent for Quebec and 11 percent for Saskatchewan. Figures 4.30 and 4.31 shows the similar impacts on employment, and federal and provincial taxes.

**Figure 4.29**
**Total GDP Impacts ($million)**

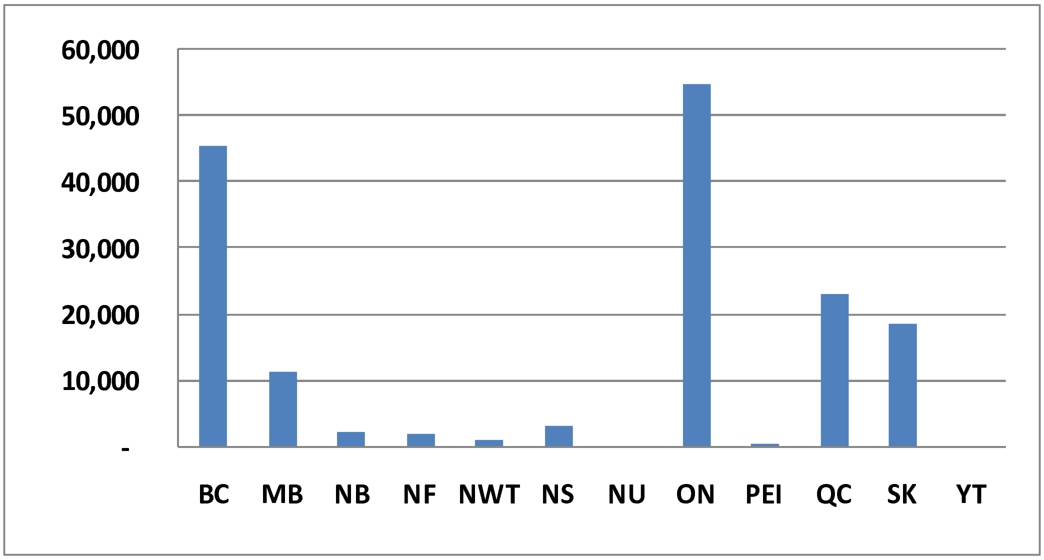



**Figure 4.30**
**Total Employment Impacts (thousand person years)**

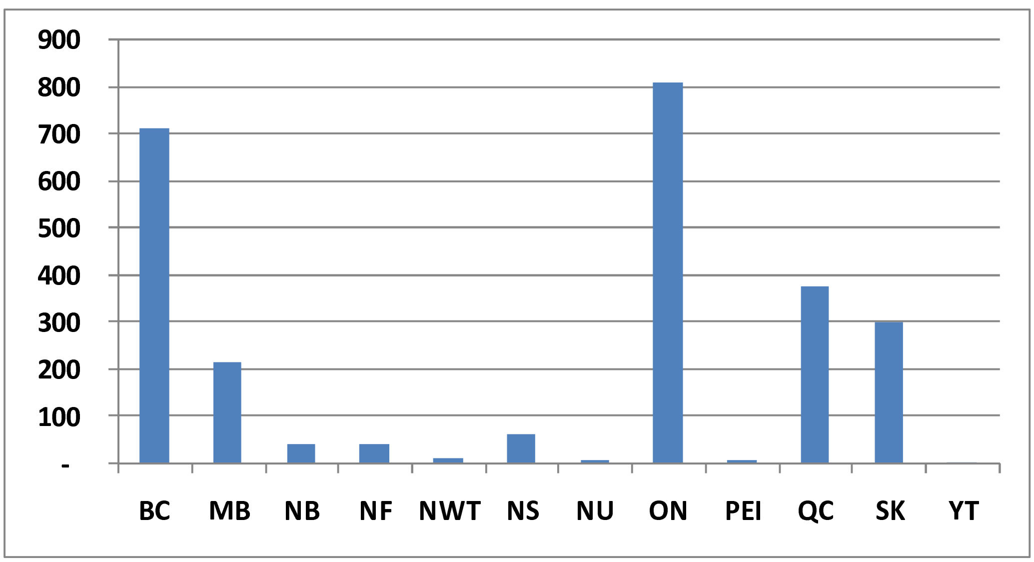
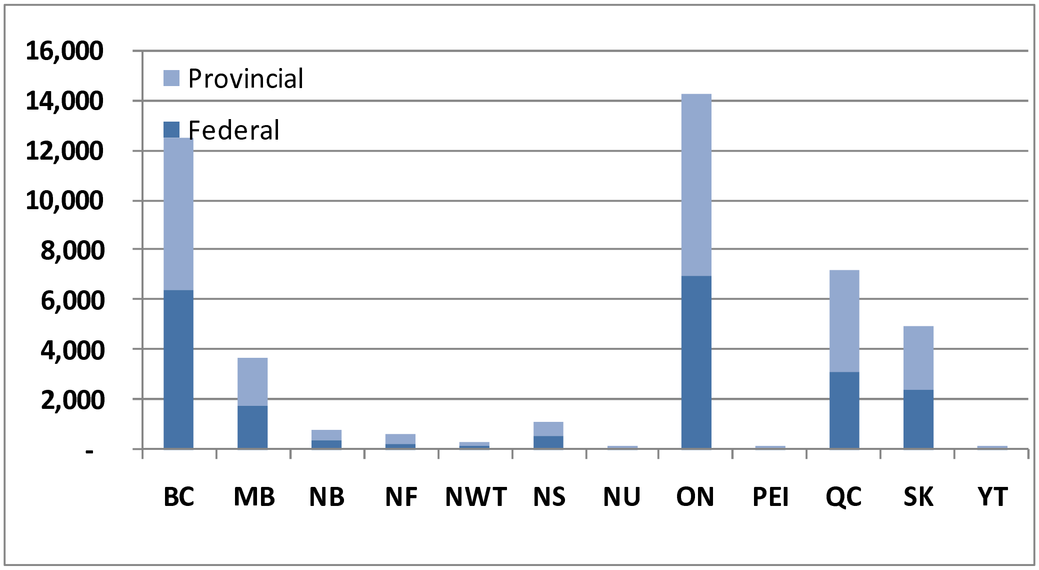


**Figure 4.31**
**Total Federal and Provincial Tax Impacts ($million)**




## 4.6 Major Capital Projects

### 4.6.1 Background

The following table presents a summary of mid-stream oil and gas projects announced in the province, as of Q1 2009. The table includes a brief description of the projects, its cost and approximate timeline. Due to the extensive nature of the list, this study, however, analyzes only the economic impacts of the Enbridge Pipeline Gateway project. The results of this are included in Section 4.6.2.

**Table 4.15**
**Summary of Alberta Major Oil and Gas Project Inventory**

| Project Name/Organization | Description | Cost ($million) | Time Duration |
|---|---|---|---|
| Enbridge Midstream Inc. | Hardisty Crude Oil Terminal (16 Tanks) | 400 | 2006-2009 |
| Keyera Facilities Income Fund | Ethane Extraction Project | 28 | 2008-2009 |
| Kinder Morgan Canada Inc. | Trans Mountain Pipeline Edmonton Terminal Expansion (13 Tanks) | 245 | 2008-2010 |
| Enbridge Athabasca | Stonefell' Terminal (Tankage and Pipelines) | 100 | 2007-2009 |
| Enbridge Inc. | Fort Hills' Bitumen / Diluent Pipelines and Terminal Facilities | 2000 | |
| Enbridge Pipelines Inc. | Line 4 Extension Project | 300 | 2008-2009 |
| Enbridge Pipelines Inc. | Alberta Clipper' Crude Oil Pipeline | 2000 | 2008-2010 |
| Enbridge Pipelines Inc. | Southern Access' Pipeline Expansion | 300 | 2005-2009 |
| Enbridge Pipelines Inc. | Gateway' Bitumen and Condensate Pipelines (Alberta portion) | 1500 | |
| Inter Pipeline Fund | Pipeline Capacity Expansion | 60 | 2008 |
| Inter Pipeline Fund | Corridor' Pipeline Expansion (Bitumen Pipeline and Pumpstation Upgrades) | 1800 | 2006-2010 |
| Kinder Morgan Canada | TMX - Anchor Loop Phase 2 | 460 | 2007-2008 |
| NOVA Gas Transmission Ltd. | North Central Corridor Natural Gas Pipeline and Associated Facilities | 983 | |
| NOVA Gas Transmission Ltd. | Northwest Mainline Extension (Dickins Lake and Vardie Lake sections) | 212 | Proposed for 2013 - 2014 |
| SemCAMS Redwillow ULC | 'Redwillow' Natural Gas Pipeline | 161 | Start late 2008 |

Sources: Inventory of Major Alberta Projects, Dec. 2008; Alberta Finance and Enterprise

### 4.6.2 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 4.16 and 4.17, 80 percent of the impacts are directly related to Alberta, with the remaining 20 percent being felt across the other provinces and territories.

**Table 4.16**
**Impacts Associated with Investment in Alberta**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 1,932 | 25 | 320 | 204 | 116 |
| **British Columbia** | 108 | 2 | 29 | 15 | 14 |
| **Manitoba** | 28 | 1 | 9 | 4 | 5 |
| **New Brunswick** | 5 | 0 | 2 | 1 | 1 |
| **Newfoundland & Labrador** | 5 | 0 | 1 | 1 | 1 |
| **Northwest Territories** | 3 | 0 | 1 | 0 | 0 |
| **Nova Scotia** | 8 | 0 | 3 | 1 | 1 |
| **Nunavut** | 1 | 0 | 0 | 0 | 0 |
| **Ontario** | 122 | 2 | 32 | 16 | 16 |
| **Prince Edward Island** | 1 | 0 | 0 | 0 | 0 |
| **Quebec** | 53 | 1 | 17 | 7 | 9 |
| **Saskatchewan** | 45 | 1 | 12 | 6 | 6 |
| **Yukon Territory** | 1 | 0 | 0 | 0 | 0 |
| **Canada** | 2,312 | 31 | 426 | 256 | 171 |

**Table 4.17**
**Impacts Associated with Operation in Alberta**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 2,489 | 32 | 412 | 263 | 150 |
| **British Columbia** | 198 | 3 | 54 | 28 | 26 |
| **Manitoba** | 52 | 1 | 16 | 8 | 9 |
| **New Brunswick** | 10 | 0 | 3 | 2 | 2 |
| **Newfoundland & Labrador** | 7 | 0 | 2 | 1 | 1 |
| **Northwest Territories** | 7 | 0 | 2 | 1 | 1 |
| **Nova Scotia** | 13 | 0 | 5 | 2 | 2 |
| **Nunavut** | 2 | 0 | 1 | 1 | 0 |
| **Ontario** | 246 | 4 | 64 | 31 | 32 |
| **Prince Edward Island** | 2 | 0 | 1 | 0 | 0 |
| **Quebec** | 92 | 2 | 29 | 12 | 16 |
| **Saskatchewan** | 77 | 1 | 20 | 10 | 10 |
| **Yukon Territory** | 2 | 0 | 1 | 1 | 0 |
| **Canada** | 3,197 | 45 | 610 | 360 | 251 |

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 4.32, Ontario receives 34 percent of the impacts, 28 percent for British Columbia, 13 percent for Quebec and 11 percent for Saskatchewan. Figures 4.33 and 4.34 show the similar impacts on employment, and federal and provincial taxes.

**Figure 4.32**
**Total GDP Impacts ($million)**

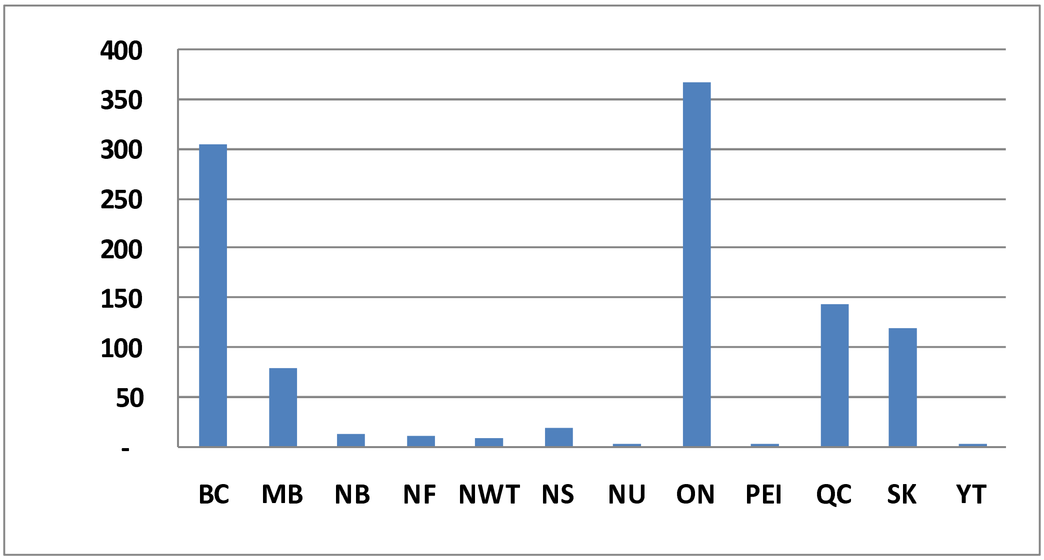



**Figure 4.33**
**Total Employment Impacts (thousand person years)**

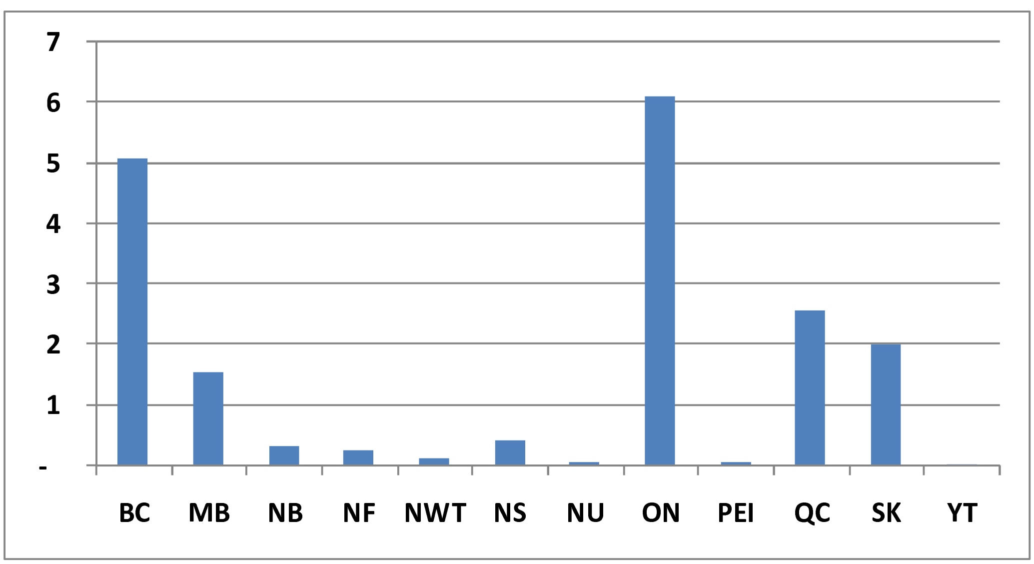
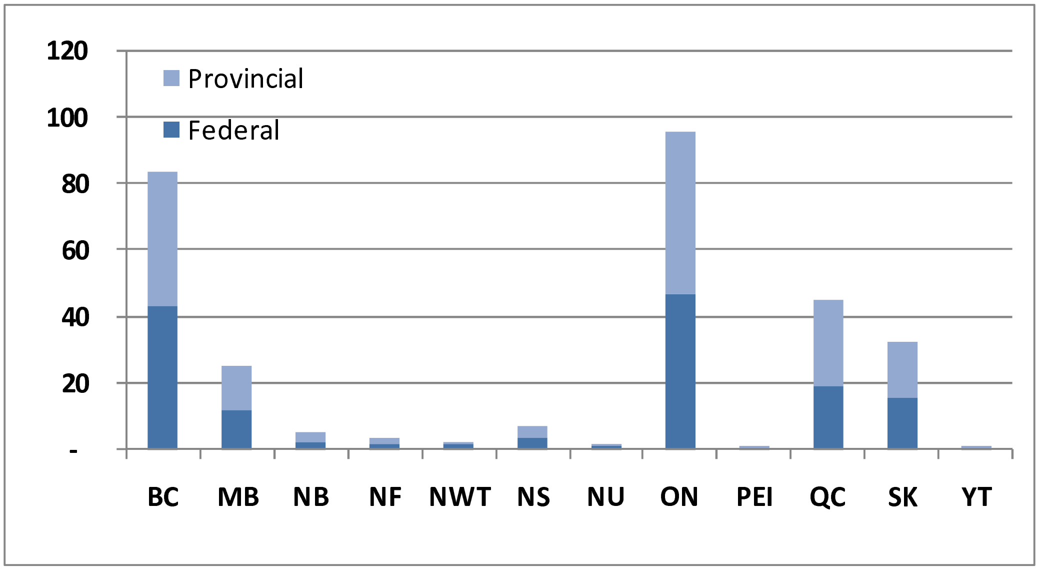


**Figure 4.34**
**Total Federal and Provincial Tax Impacts ($million)**



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# CHAPTER 5
# ECONOMIC IMPACTS: BRITISH COLUMBIA

This chapter discusses the economic impacts for the province of British Columbia. It is divided into five sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in British Columbia. The following four sections discuss and review the economic impacts of conventional oil resources, conventional gas resources, shale/tight gas resources, and major capital projects in the province. Each section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 5.1 Background

This section describes the reserves, production, and expenditures of the petroleum industry in the province of British Columbia. In this section, the methodology that has been used for regrouping components of petroleum industry's expenditures, and their disaggregation into oil and natural gas is demonstrated.

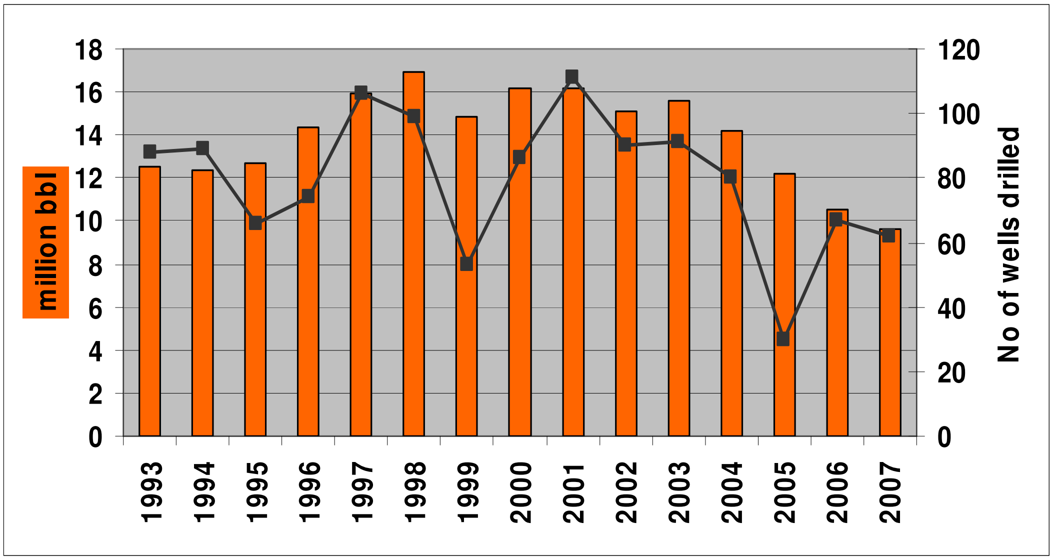
### 5.1.1 Reserves and Production

According to CAPP, the remaining established reserves of crude oil in British Columbia are 117 million bbl. Estimated as of December 2006; this is a net decrease of 13 percent from 2005.

Crude oil production in British Columbia has been on a downward trend since 2003 and is down from 1993 levels. Production declined at an average annual rate of 1.9 percent over this time period. In 2007, British Columbia produced slightly less than 10 million barrels of oil. Crude oil production and the number of wells drilled are illustrated in Figure 5.1. Not surprisingly, the number of oil wells drilled also declined from 88 wells in 1993 to 62 wells in 2007.

The crude oil reserves production ratio is approximately 12 years.

**Figure 5.1**
**British Columbia Crude Oil Production and Number of Wells Drilled**
**1993 - 2007**



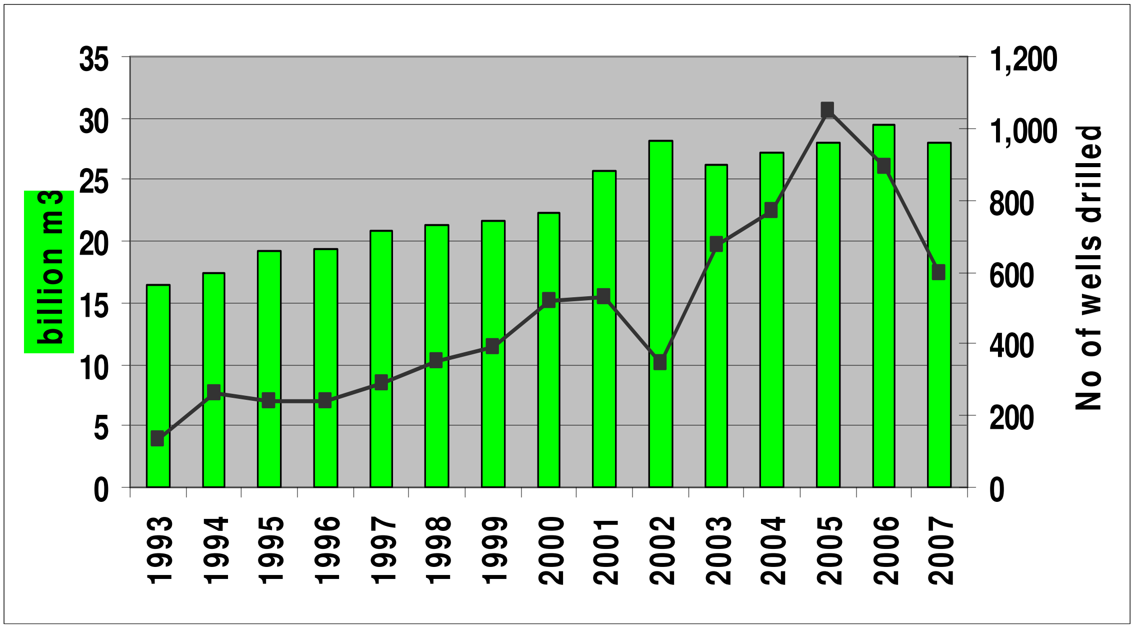

Source: CAPP, Statistical Handbook, September 2008.

According to CAPP, as of December 2006, the remaining established reserves of marketable natural gas were 367.6 billion cubic meters, an increase of almost 19 billion $m^3$ from the previous year.

Figure 5.2 illustrates marketable natural gas production and the number of wells drilled between 1993 and 2007. Marketable natural gas production in British Columbia increased from 16.4 billion $m^3$ in 1993 to 28.1 billion $m^3$ in 2007, an average annual growth rate of 3.9 percent. Over the same period, the number of gas wells drilled increased from 134 wells in 1993 to 597 wells in 2007. The number of gas well drilled peaked at 1,049 in 2005, and has subsequently declined.

The natural gas reserves production ratio is about 13 years.

**Figure 5.2**
**British Columbia Marketable Natural Gas Production and Number of Wells Drilled**
**1993 - 2007**




Source: CAPP, Statistical Handbook, September 2008.

### 5.1.2 Expenditures of the Petroleum Industry in British Columbia

The Canadian Association of Petroleum Producers[33] reports the net cash expenditures[34] of British Columbia petroleum industry for exploration, development, operating and royalties as follows.

A- Exploration
  - A1- Geological & Geophysical
  - A2- Drilling
  - A3- Land

B- Development
  - B1- Drilling
  - B2- Field Equipment
  - B3- EOR
  - B4- Gas Plant

C- Operating
  - C1- Wells & Flow lines
  - C2- Gas Plants

D- Royalties

According to CAPP[35], in 2007 $8.2 billion dollars were spent by the petroleum industry in British Columbia. The largest investment expenditures were for development, approximately 40 percent.

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[33] Canadian Association of Petroleum Producers, *Statistical Handbook*.
[34] Net cash expenditure exclude inter-industry transactions
[35] Canadian Association of Petroleum Producers, *Statistical Handbook*.

Exploration, operating and royalties follow this at 27 percent, 18 percent and 15 percent, respectively.

Table 5.1 summarizes the methodology, which will be referred to in latter sections, that has been used for regrouping the components of petroleum expenditures to the following: drilling investment expenditure, field equipment investment expenditure and operating expenditure.

**Table 5.1**
**Disaggregation of Oil and Gas Expenditures**

| Crude Oil | Natural Gas |
|---|---|
| Drilling Expenditure:<br>A1 + A2 + B1 | Drilling Expenditure:<br>A1 + A2 + B1 |
| Field Equipment Expenditure:<br>B2 + B3 | Field Equipment Expenditure:<br>B2 + B4 |
| Operating Expenditure:<br>C1 | Operating Expenditure:<br>C1 + C2 |

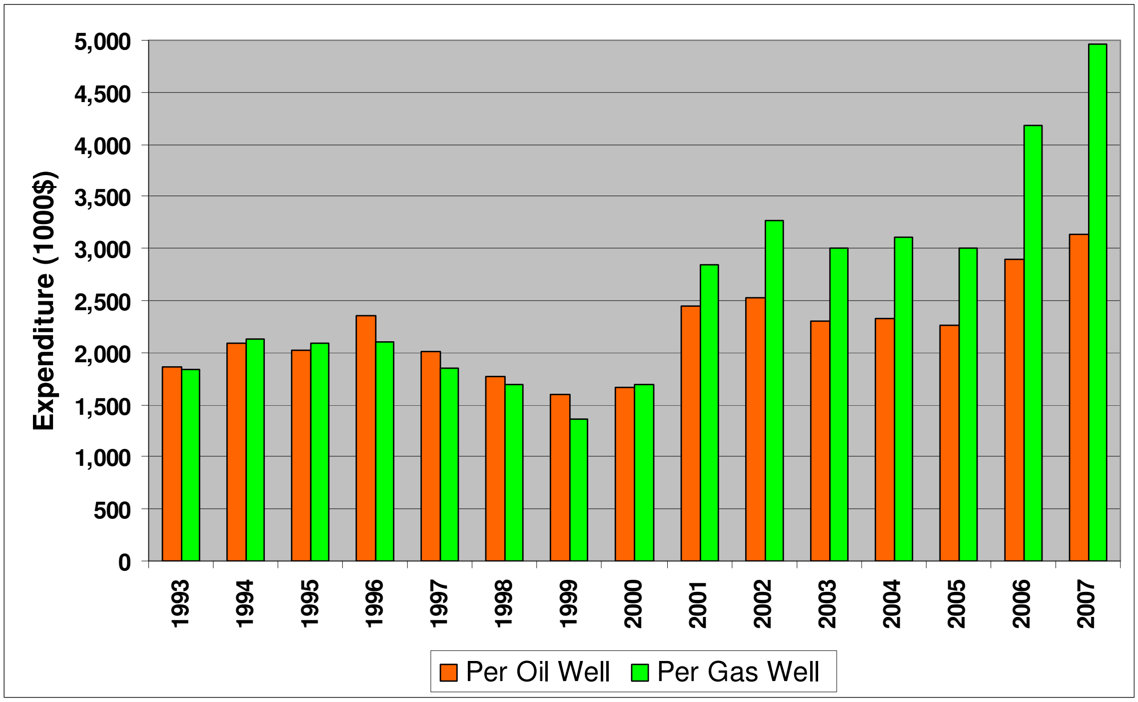
Drilling Investment Expenditure

In 2007, British Columbia drilled 659 oil and gas wells, of which more than 90 percent were natural gas. In the same year, total depth of drilled wells was 1.3 million meters. The share of natural gas wells was approximately 94 percent.

Between 1955 and 2007, CAPP reports a total of 2,823 oil wells and 9,853 gas wells drilled in British Columbia. Drilling expenditures of petroleum industry (A1, A2, and B1) are taken from CAPP's Statistical Handbook, released in September 2008. These expenditures are disaggregated into oil and gas in proportion to meters oil and gas drilled wells.

Figure 5.3 shows that in the last eight years, British Columbia drilling investment per well was greater for natural gas than for oil, approximately $3.1 million per oil well and $4.9 million per gas well. Both are at record levels for the province.

**Figure 5.3**
**British Columbia Oil and Gas Drilling Investment per Well Drilled**
**1993 - 2007**



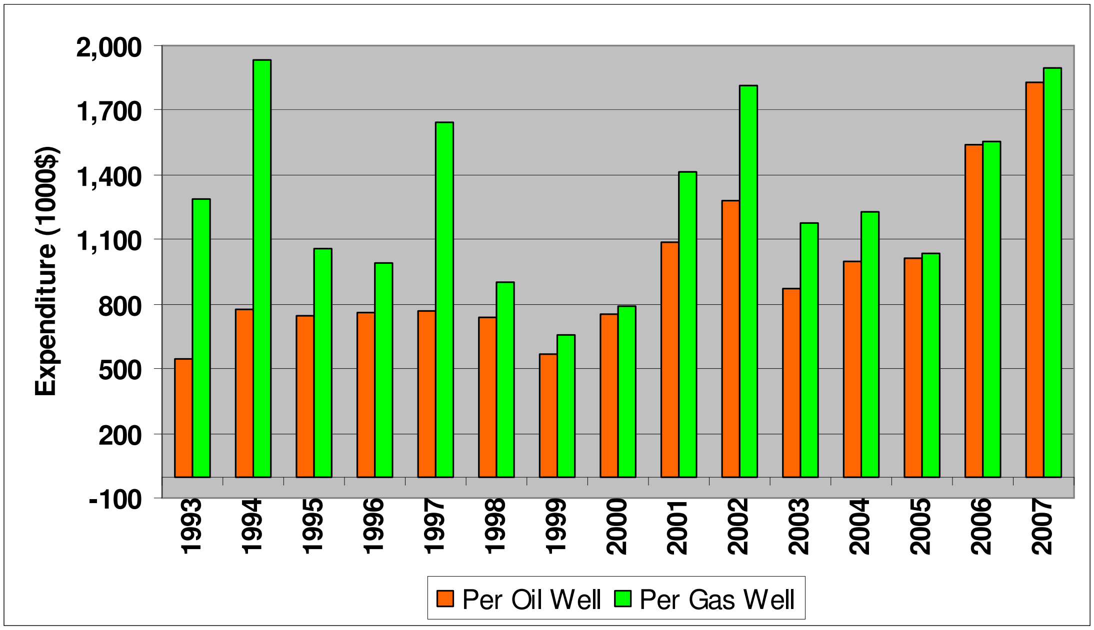

Source: CAPP, Statistical Handbook, September 2008.

<u>Field Investment Expenditure</u>

The major part of field equipment expenditures results from field facilities, crude oil battery and gathering systems. CAPP reports combined oil and gas field equipment expenditure (B2). CERI has disaggregated the above expenditures into oil and gas in proportion to the number of wells drilled. Enhanced oil recovery expenditure (B3) was added to oil field investment; similarly, gas plant expenditure (B4) was added to the gas field investment.

It should be noted that from 2005 to 2007, field investment per oil and gas wells were almost identical. In 2007, field investment per oil well and per gas well was approximately $1.8 million, as illustrated in Figure 5.4.

**Figure 5.4**
**British Columbia Oil and Gas Field Expenditure per Well Drilled**
**1993-2007**

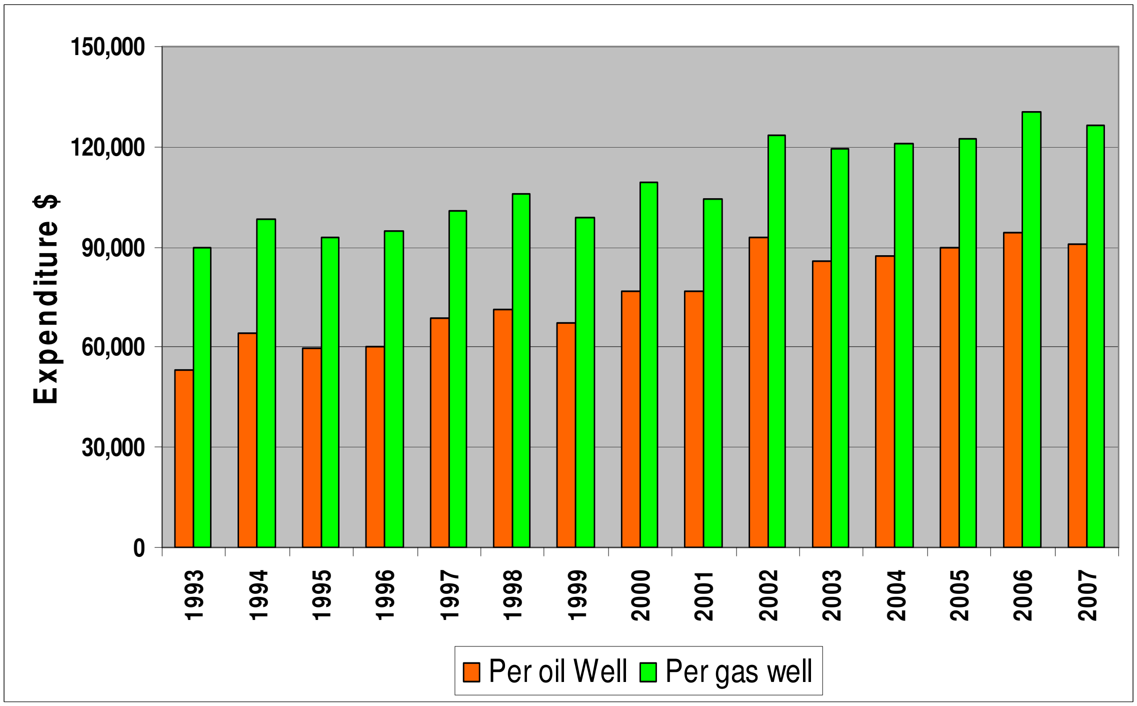



Source: CAPP, Statistical Handbook, September 2008.

Operating Expenditure

For estimation of per well operating expenditures, CERI assumes that "wells and flow lines" operating expenditures (C1) for oil and gas are the same, and therefore divides C1 by the total cumulative combined oil and gas wells drilled. Gas plant operating expenditure (C2) per cumulative well is added to the operating expenditure of gas wells. This is illustrated in Figure 5.5 below.

**Figure 5.5**
**British Columbia Oil and Gas Operating Expenditures per Cumulative Successful Well 1993-2007**




Source: CAPP, Statistical Handbook, September 2008.

Operating expenditures per gas well were higher than oil for each year observed in Figure 5.6, both, however, are near record levels. In 2007, operating expenditures per cumulative successful oil well were approximately $90,000 and gas well were $126,000.

## 5.2 Conventional Oil Resources

### 5.2.1 Background

Since 1950, when development began near Fort St. John, more than 30 conventional oil fields have been developed in British Columbia. As illustrated in Figure 5.6, oil reserves are concentrated solely in the northeast corner of the province.[36]

[36] Centre for Energy, *British Columbia Energy Facts & Statistics*. http://www.centreforenergy.com/FactsStats/MapsCanada/BC-EnergyMap.asp

**Figure 5.6**
**Oil Reserves in British Columbia**


Source: Centre for Energy.

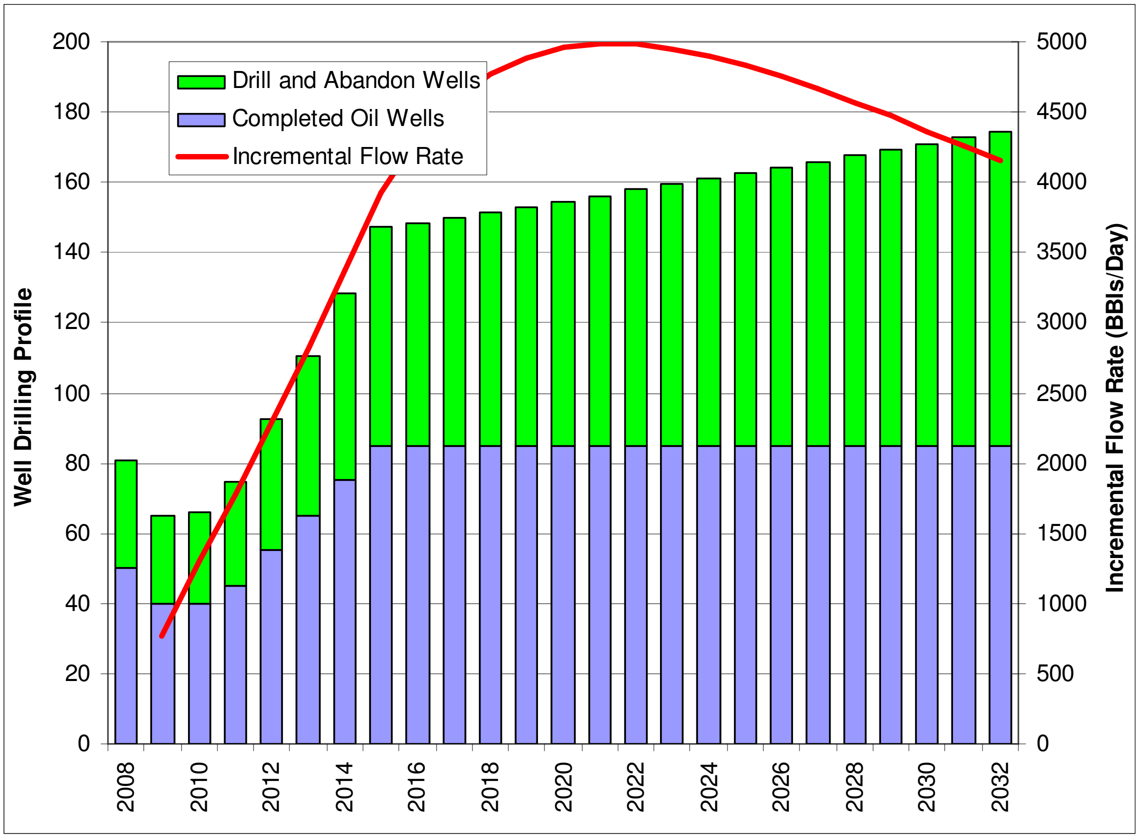
In 2006, 1,100 active conventional oil wells produced on averaged around 4,100 $m^3$ of oil per day. During the year, 62 new wells were drilled, continuing a largely decreasing trend in drilling activity since 2001.[37] By year end 2006, reserves of conventional oil were estimated to be 18.6 million $m^3$.[38]

### 5.2.2 Forecasts

Figure 5.7 represents CERI's view of conventional oil resource developments broken down into forecasted new oil well connections and associated non-productive wells that are a typically part of the exploration and development activities. The latter are labeled dead and abandoned wells. This figure also indicates the resulting incremental oil flow rate from the completed oil wells.

[37] Canadian Association of Petroleum Producers, Industry Facts and Information, British Columbia. *British Columbia Statistics for the Past Eight Years.*. http://membernet.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=34089
[38] Ibid.

**Figure 5.7**
**Well Drilling Profile and Incremental Flow Rate in British Columbia (25-Year Forecast)**




### 5.2.3 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 5.2 and 5.3, 91 percent of the impacts are directly related to British Columbia, with the remaining 9 percent being felt across the other provinces and territories.

**Table 5.2**
**Impacts Associated with Investment in British Columbia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 188 | 2 | 31 | 20 | 11 |
| **British Columbia** | 5,718 | 40 | 1,564 | 805 | 759 |
| **Manitoba** | 27 | 0 | 9 | 4 | 5 |
| **New Brunswick** | 9 | 0 | 3 | 1 | 1 |
| **Newfoundland & Labrador** | 5 | 0 | 2 | 1 | 1 |
| **Northwest Territories** | 3 | 0 | 1 | 1 | 0 |
| **Nova Scotia** | 11 | 0 | 4 | 2 | 2 |
| **Nunavut** | 1 | 0 | 0 | 0 | 0 |
| **Ontario** | 175 | 3 | 45 | 22 | 23 |
| **Prince Edward Island** | 2 | 0 | 1 | 0 | 0 |
| **Quebec** | 85 | 1 | 26 | 11 | 15 |
| **Saskatchewan** | 36 | 1 | 10 | 5 | 5 |
| **Yukon Territory** | 3 | 0 | 1 | 1 | 0 |
| **Canada** | 6,263 | 48 | 1,697 | 873 | 824 |

**Table 5.3**
**Impacts Associated with Operation in British Columbia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 86 | 1 | 14 | 9 | 5 |
| **British Columbia** | 2,610 | 18 | 714 | 367 | 346 |
| **Manitoba** | 13 | 0 | 4 | 2 | 2 |
| **New Brunswick** | 4 | 0 | 1 | 1 | 1 |
| **Newfoundland & Labrador** | 2 | 0 | 1 | 0 | 0 |
| **Northwest Territories** | 2 | 0 | 0 | 0 | 0 |
| **Nova Scotia** | 5 | 0 | 2 | 1 | 1 |
| **Nunavut** | 0 | 0 | 0 | 0 | 0 |
| **Ontario** | 80 | 1 | 21 | 10 | 11 |
| **Prince Edward Island** | 1 | 0 | 0 | 0 | 0 |
| **Quebec** | 39 | 1 | 12 | 5 | 7 |
| **Saskatchewan** | 16 | 0 | 4 | 2 | 2 |
| **Yukon Territory** | 1 | 0 | 1 | 0 | 0 |
| **Canada** | 2,859 | 22 | 774 | 399 | 376 |

In addition to the economic impacts listed in the previous tables, the royalties payable to the province of British Columbia in regard to British Columbia conventional oil, over the next 25-years, will be $897 million. On average, this equates to approximately $36 million per year.

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 5.8, Alberta receives 34 percent of the impacts, 32 percent for Ontario, 15 percent for Quebec and 6.5 percent for Saskatchewan. Figures 5.9 and 5.10 show the similar impacts on employment, and federal and provincial taxes.

**Figure 5.8**
**Total GDP Impacts ($million)**

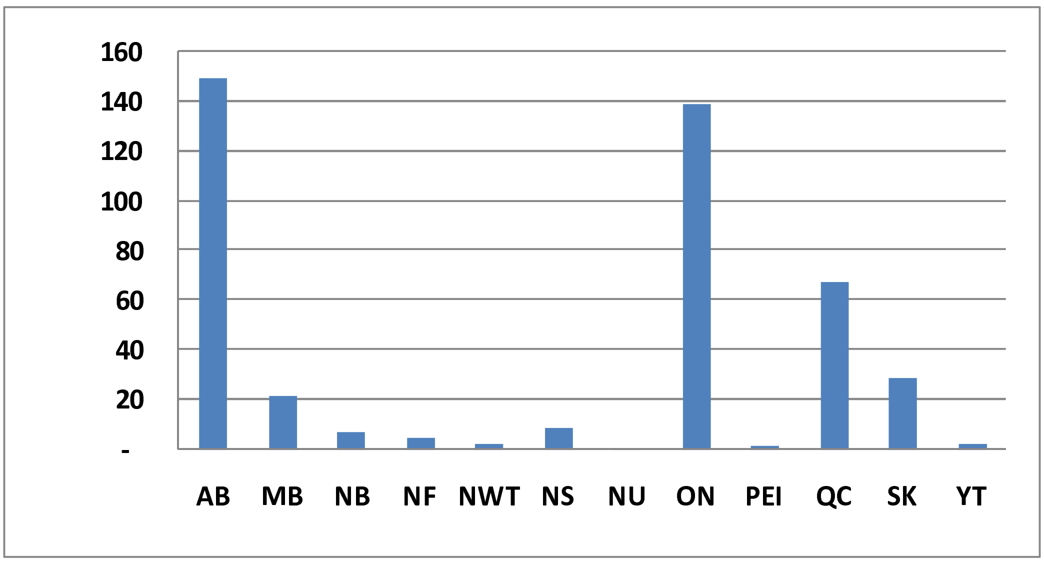


**Figure 5.9**
**Total Employment Impacts (thousand person years)**

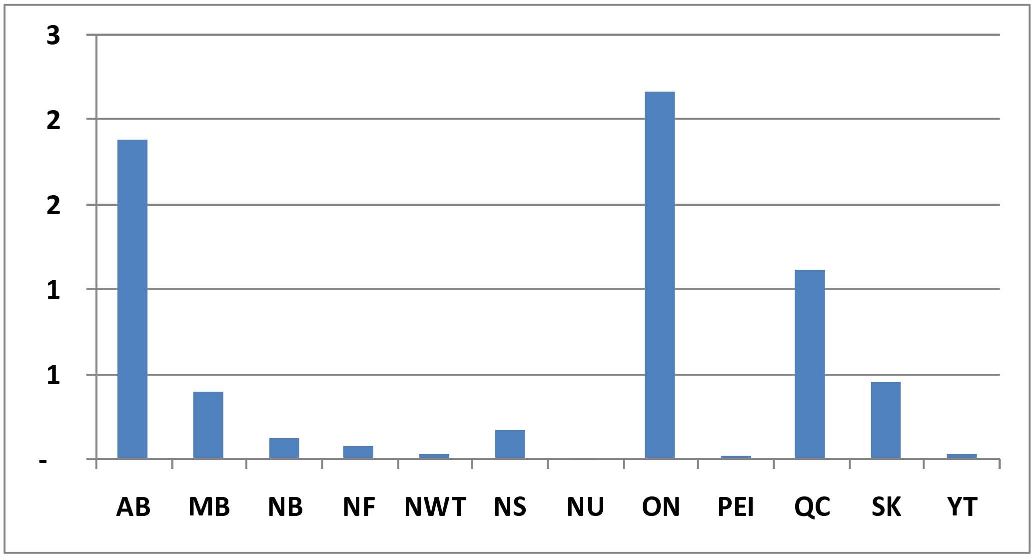
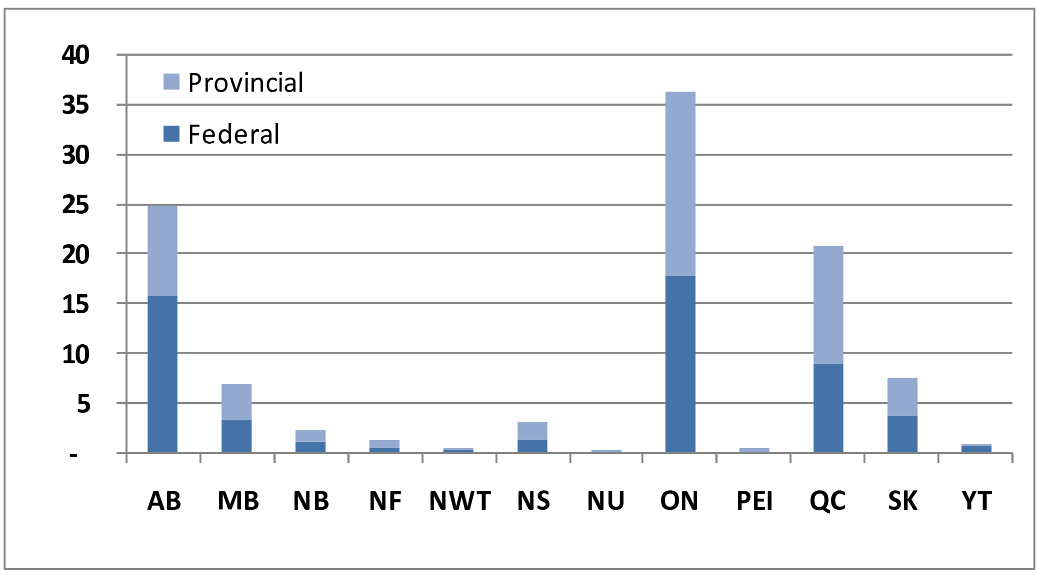



**Figure 5.10**
**Total Federal and Provincial Tax Impacts ($million)**



## 5.3 Conventional Gas Resources

### 5.3.1 Background

Like conventional oil, the commercial development of conventional natural gas in British Columbia began in the early 1950s in the proximity of Fort St. John. And like conventional oil, as the graphic bellow shows, gas pools are also concentrated in the northeast part of the province.[39]

**Figure 5.11**
**Natural Gas Reserves in British Columbia**


Source: Centre for Energy.

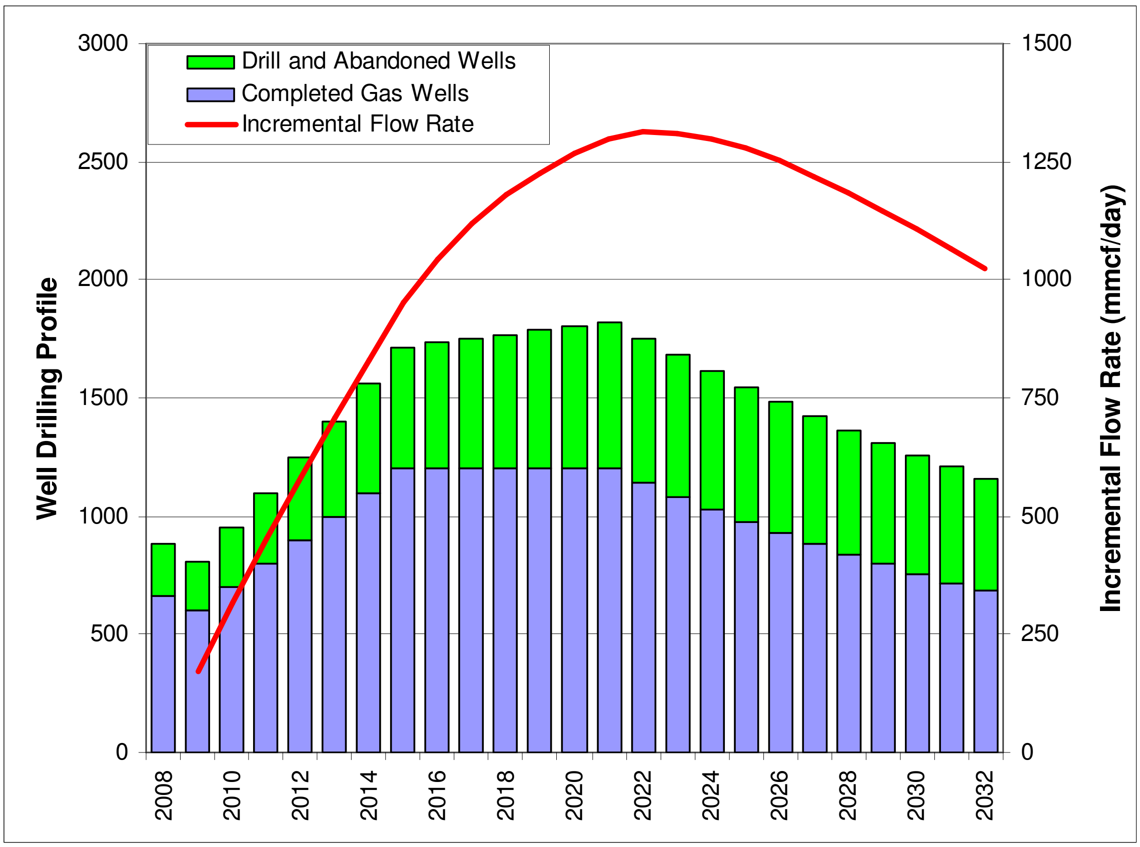
By the end of 2007, 18,811 billion cubic feet of conventional natural gas had been produced in British Columbia. Remaining marketable gas reserves at the end of 2007 were estimated to be 13,965 billion cubic feet. There were 749 new wells connected in 2007, which was less than the new connections from 2004 to 2006.

[39] Ibid.

### 5.3.2 Forecasts

The figure below represents CERI's view of conventional gas resource developments broken down into forecasted new gas well connections and associated non-productive wells that are a typically part of the exploration and development activities. The latter are labeled dead and abandoned wells. This figure also indicates the resulting incremental gas flow rate from the completed gas wells.

**Figure 5.12**
**Well Drilling Profile and Incremental Flow Rate in British Columbia (25-Year Forecast)**




### 5.3.3 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 5.4 and 5.5, 91 percent of the impacts are directly related to British Columbia, with the remaining 9 percent being felt across the other provinces and territories.

**Table 5.4**
**Impacts Associated with Investment in British Columbia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 1,619 | 20 | 268 | 171 | 97 |
| **British Columbia** | 49,261 | 345 | 13,472 | 6,932 | 6,539 |
| **Manitoba** | 229 | 4 | 73 | 35 | 38 |
| **New Brunswick** | 73 | 1 | 25 | 13 | 13 |
| **Newfoundland & Labrador** | 46 | 1 | 14 | 6 | 8 |
| **Northwest Territories** | 29 | 0 | 7 | 5 | 2 |
| **Nova Scotia** | 101 | 2 | 36 | 17 | 19 |
| **Nunavut** | 7 | 0 | 3 | 3 | 1 |
| **Ontario** | 1,508 | 23 | 391 | 192 | 199 |
| **Prince Edward Island** | 14 | 0 | 6 | 3 | 3 |
| **Quebec** | 729 | 12 | 226 | 97 | 128 |
| **Saskatchewan** | 310 | 5 | 82 | 41 | 42 |
| **Yukon Territory** | 26 | 0 | 12 | 8 | 4 |
| **Canada** | 53,953 | 415 | 14,615 | 7,521 | 7,094 |

**Table 5.5**
**Impacts Associated with Operation in British Columbia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 2,084 | 26 | 345 | 220 | 125 |
| **British Columbia** | 63,405 | 444 | 17,340 | 8,923 | 8,417 |
| **Manitoba** | 295 | 5 | 94 | 45 | 49 |
| **New Brunswick** | 95 | 2 | 33 | 16 | 16 |
| **Newfoundland & Labrador** | 59 | 1 | 18 | 8 | 10 |
| **Northwest Territories** | 37 | 0 | 9 | 6 | 3 |
| **Nova Scotia** | 130 | 2 | 46 | 22 | 24 |
| **Nunavut** | 9 | 0 | 4 | 3 | 1 |
| **Ontario** | 1,941 | 30 | 503 | 247 | 256 |
| **Prince Edward Island** | 19 | 0 | 8 | 4 | 4 |
| **Quebec** | 938 | 16 | 291 | 125 | 165 |
| **Saskatchewan** | 400 | 6 | 106 | 52 | 54 |
| **Yukon Territory** | 33 | 0 | 15 | 10 | 5 |
| **Canada** | 69,444 | 534 | 18,812 | 9,681 | 9,131 |

In addition to the economic impacts listed in the previous tables, the royalties payable to the province of British Columbia in regard to British Columbia conventional gas, over the next 25-years, will be $21,003 million. On average, this equates to approximately $840 million per year.

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 5.13, Alberta receives 35 percent of the impacts, 32 percent for Ontario, 16 percent for Quebec and 7 percent for Saskatchewan. Figures 5.14 and 5.15 show the similar impacts on employment, and federal and provincial taxes.

**Figure 5.13**
**Total GDP Impacts ($million)**

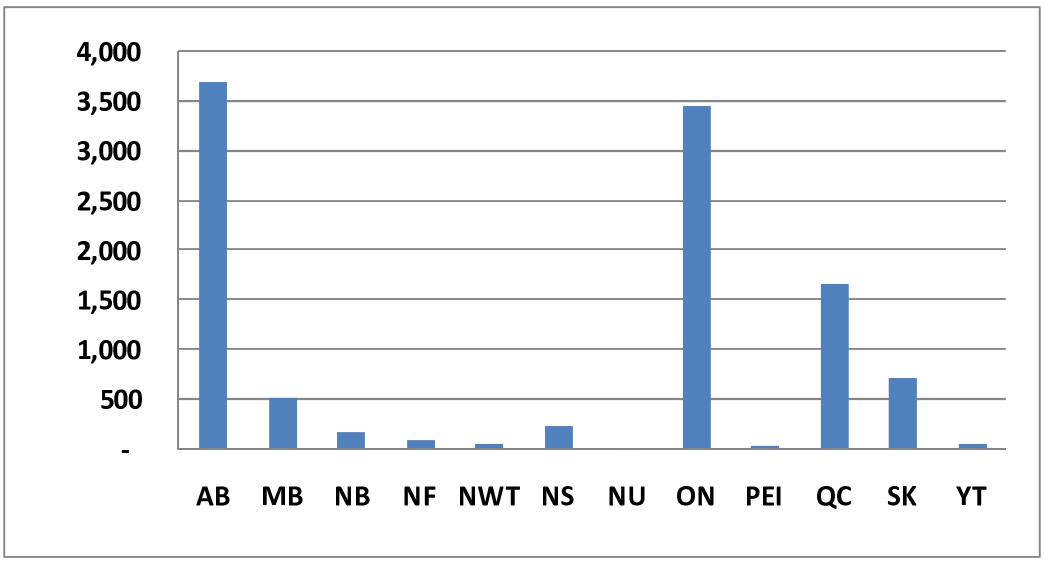


**Figure 5.14**
**Total Employment Impacts (thousand person years)**

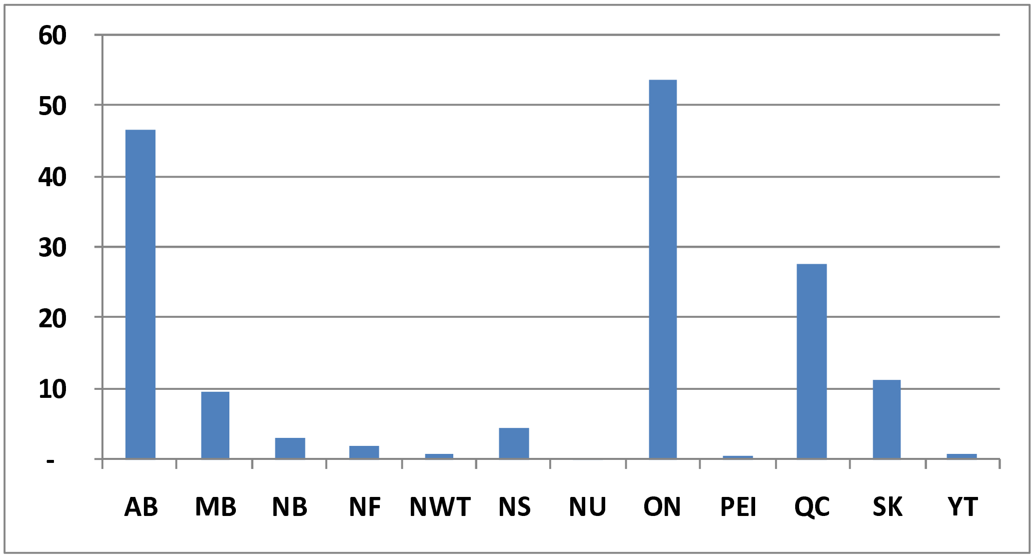
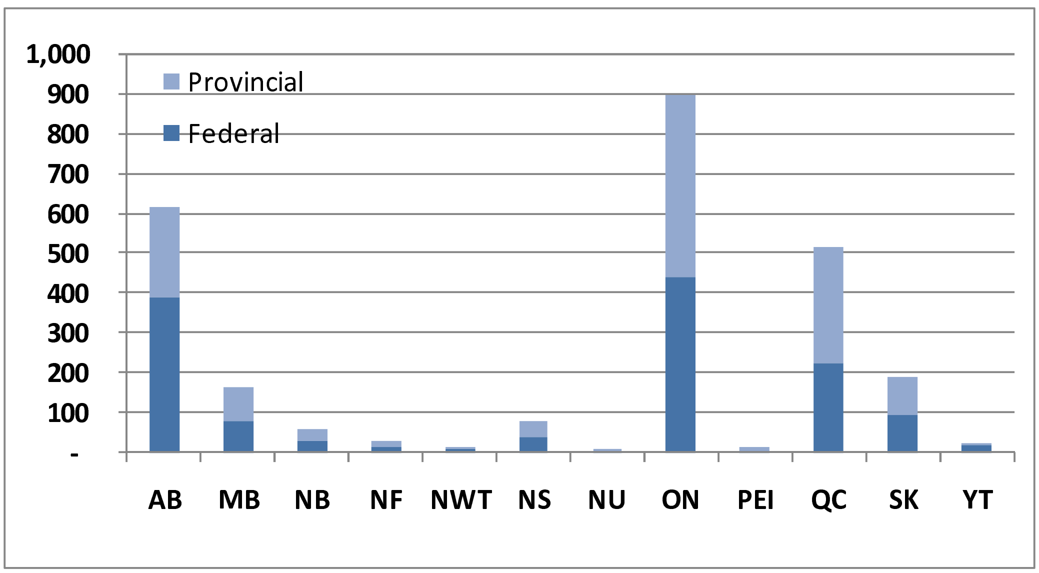



**Figure 5.15**
**Total Federal and Provincial Tax Impacts ($million)**




## 5.4 Shale/Tight Gas Resources

The following section presents a brief overview of shale gas and tight gas geology, reviews British Columbia's resources and provides a discussion of potential constraints. As with previous sections, the remainder of this section reviews forecasts as well as the economic impacts of this particular resource to the province and the rest of Canada.

### 5.4.1 Background

5.4.1.1 Shale/Tight Gas Background

Shale gas is natural gas stored in dark coloured, organic rich rocks. Although considered source rocks in the past, shales can act as the source, reservoir, and seal for the gas. According to the Centre for Energy, the natural gas molecules are generally stored in three ways: adsorbed into the organic matter in the shales, trapped in the pore spaces of the fine-grained sediments interbedded with the shale, or trapped in fractures within the shale itself.[40] The exploitable occurrences are, however, typically low permeability, with low production rates from the natural fracture system. Tight gas, like shale gas, is another form of unconventional natural gas. Tight gas is gas that is stuck in a very tight formation underground, trapped in unusually impermeable, hard rock, or in sandstone or limestone formation that is unusually impermeable and non-porous (tight sand).[41]

The recent boom in shale gas development in the US and increased interest in Canada is, in part due to rapid technological advancements in drilling and the stimulations of the shale-bearing formations. Fracturing (Fracking) and other forms of stimulation are necessary to release tight gas. British Columbia is the Canadian province that is attracting the most attention from Exploration and Production (E&P) companies. Shale gas and tight gas hold enormous supply potential in the province. The shale gas potential is in rocks from several parts of British Columbia, ranging from the prolific Western Canada Sedimentary Basin (WCSB) to the Bowser Basin north central part of the province.

While production volumes from shale gas resources in Canada are currently insignificant, compared to that in the United States, there is substantial potential for future growth. Energy companies, led by shale gas discoveries, have added $220 million to British Columbia's land sale coffers in the September 2008 auction. According to the Ministry of Energy, Mines and Petroleum Resources, British Columbia closed out the 2008-09 fiscal year with an all-time high of $2.4 billion sold—more than doubling the previous record set in 2007. [42]

Production from British Columbia shale and tight gas will likely play a large role in mitigating the effects of declining conventional production on total production in Canada. In its report, *Short-term Natural Gas Deliverability 2008-2010,* the NEB suggests that production is expected to decrease by 7 percent by 2010. The report suggests that the Horn River and Montney plays could alter the projections of decline.

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[40] Centre For Energy, http://www.centreforenergy.com/generator.asp?xml=/silos/ong/ShaleGas/shaleGasOverview01XML.asp&template=1,2,4

[41] http://www.naturalgas.org/overview/unconvent_ng_resource.asp

[42] Marketwire, Press Release, "Government of British Columbia: Oil and Gas Produce Record-Breaking Fiscal Year". http://www.marketwire.com/press-release/Government-Of-British-Columbia-966555.html, March 26, 2009.

5.4.1.2 Resources

While there are several shale and tight gas formations that are attracting attention, there are three that are particularly noticeable: the Ootla/Muskwa Shale (Horn River), the Montney Shale and the Jean Marie.

The Ootla/Muskwa Shale, Horn River Basin

Horn River is located in northeastern British Columbia and stretches north up to Fort Liard, southern Northwest Territories. According to Platts, in early May 2008 the Scotland-based Wood Mackenzie stated that the Horn River Basin could rival the Barnett Shale, with recoverable reserves in the region at 37 Tcf and easily rising to 50 Tcf or greater as drilling activity increases. Industry pundits suggest that the Horn River Basin may one-day rival Alaska's North Slope. The Horn River Basin, according to CSUG, may contain over 500 Tcf of original gas in place (OGIP).[43]

It is important to note that particular shale formations have unique properties and characteristics, depending on porosity, thickness, brittleness and permeability. The Ootla/Muskwa shale lies in at a depth range of 7,800-13,300 ft. and is located predominantly in northeast British Columbia. In terms of thickness, the Ootla/Muskwa shale, with thickness ranging between 360 ft. and 580 ft., is comparable to the Barnett shale, which ranges in thickness from 150 ft. to 700 ft. Table 5.6 provides a summary of Horn River's key characteristics.

**Table 5.6**
**Horn River Characteristics**

| Parameter | Muskwa/Ootla, Horn River |
|---|---|
| Depth Range (ft) | 7800 to 13300 |
| Shale thickness (ft) | 360 to 580 |
| GIP/sq mi (Bcf) | 180 to 320 |
| Porosity (%) | 4.0 |
| Total organic carbon (%) | 3.0 |
| Thermal maturity (Ro) | 2.8 |
| Expected Recovery Factor (%) | 20-30 |
| Lateral lengths (ft) | 4600 to 8200 |
| Fracturing stages | 6 to 12 |
| Initial production rates (MMcf/d) | 5 to 12 |
| Expected EUR/Well (Bcfe) | 4 to 6 |
| Average well cost ($MM) | 7 to 10 |
| Typical Well Spacing (acres/well) | 40 |
| Expected F&D/Mcfe | 2.0 |

Source: Deutsche Bank, 2008.

The enormous potential of the Horn River Basin is attracting large independent producers, as well as several mid-sized E&P companies. Currently, the top landholders in the region are EnCana

[43] F.M., Dawson, "Shale Gas in North America: Emerging Supply Opportunities", Canadian Society for Unconventional Gas, October, 2008.

Corp., Apache Corp., EOG Resources, and Nexen Inc. Together these four companies hold exploration rights to over 760,000 net acres of Horn River land.

EnCana began purchasing land in the Horn River Basin in 2003, and now holds 260,000 net acres in the region. In 2008, the company drilled 4 horizontal wells using techniques similar to those used in the Texas Barnet.[44] EnCana's 50/50 joint venture with Apache in the Horn River produced extremely positive results in 2008. Initial production rates for the first 30 days of production were reported to reach 8 MMcfpd.[45] Apache's plans include drilling 25 wells and installing a 24" pipeline in 2009.[46]

EOG Resources holds 157,500 net acres of Horn River land. Due to the regions limited pipeline infrastructure, EOG does not believe full scale production will be possible until 2012. EOG will drill seven horizontal wells in the Horn River formation in 2009.[47]

Nexen announced the potential for a net 3 to 6 Tcf of recoverable reserves in the Horn River Basin, where it has 123,000 net acres in the play, and drilled and tested several wells over the past two years. Nexen's 2009 capital budget plans include the drilling of seven test wells in the Horn River Basin.[48] $160 million of Nexen's $690 million 2009 exploration program has been allocated to Horn River developments.[49]

Other companies with significant land holdings in the Horn River Basin include ExxonMobil, Devon, and Quicksilver Resources.

The Montney Shale

Although geologists have known about the Triassic-aged Montney formation for many years, it was largely ignored until recent years. As with other shale plays, advancements in technology and a high market price for natural gas, have encouraged exploration and development in British Columbia's Montney Shale play.

The Gas Technology Institute (GTI) estimates that the Montney and neighbouring Doig formations may hold over 300 Tcf. Industry estimates range from 50 Tcf up to 700 Tcf in place. In 2008, the Canadian Society for Unconventional Gas estimated that the Montney Shale's OGIP

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[44] EnCana News Release, June 16, 2008.
[45] Oil Voice, "EnCana Generates Third Quarter Cash Flow of US$2.8 billion" http://www.oilvoice.com/n/EnCana_Generates_Third_Quarter_Cash_Flow_of_US28_billion/0fce3636.aspx, October 23, 2008.
[46] Roger, Plank, CFO Apache Corporation, Presentation at the Credit Suisse Annual Energy Conference, February 5, 2009.
[47] Patrick Johnston, and Shannon Nome, Deutsche Bank. Global Market Research, EOG Resources. February 5, 2009.
[48] Nexen Inc. News Release, http://www.nexeninc.com/Newsroom/News_Releases/attachments/928578.pdf. December 9, 2008.
[49] Ibid.

could be as high as 250 Tcf.[50] Recoverable gas volumes from shale are typically low – in the 20 percent range. However, analysts believe that the recovery factor in British Columbia's Montney Shale could be much higher, at up to 50 percent.[51]

The Montney formation is a mature shale and tight gas play in British Columbia, extending into Alberta (where it is referred to as Doig). The British Columbia portion of the Montney is located south of the Horn River Basin, near Dawson Creek. Consisting of a blend of low-permeability sandstone, siltstone, and shale, the Montney is sometimes also referred to as a tight shale play or tight gas play.

Table 5.7 provides a summary of key characteristics of the British Columbia Montney Shale.

**Table 5.7**
**Montney Shale Characteristics**

| Parameter | Montney |
|---|---|
| Depth Range (ft) | 6600 to 8200 |
| Shale thickness (ft) | 950+ |
| GIP/sq mi (Bcf) | 75 to 100 |
| Porosity (%) | 6.0 |
| Total organic carbon (%) | 2.5-6.0 |
| Thermal maturity (Ro) | 1.4-2.5 |
| Expected Recovery Factor (%) | Up to 50% |
| Lateral lengths (ft) | 5000 |
| Fracturing stages | 8 to 11 |
| Initial production rates (MMcf/d) | 5 to 10 |
| Expected EUR/Well (Bcfe) | 2.5 |
| Average well cost ($MM) | 4 to 6 |
| Typical Well Spacing (acres/well) | 80-160 |
| Expected F&D/Mcfe | 2.0-2.5 |

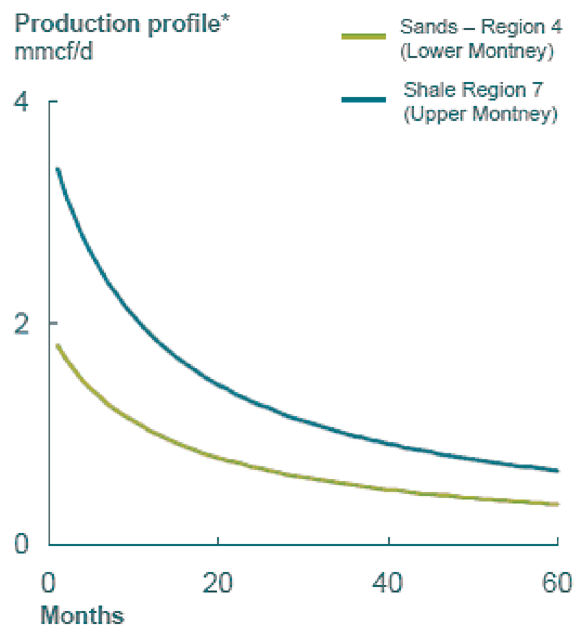
Source: Deutsche Bank, 2008. Talisman, 2009.

Production in the Montney formation is characterized by high initial flow rates, followed by steep declines and low, but stable, long-term output. Figure 5.16 displays horizontal type curves for Upper Montney and Lower Montney plays.

[50] F.M., Dawson, "Shale Gas in North America: Emerging Supply Opportunities", Canadian Society for Unconventional Gas, October, 2008.

[51] Patrick Johston, and Shannon Nome, "From Shale to Shining Shale: A primer on North American natural gas shale plays", Deutsche Bank, July 22, 2008.

**Figure 5.16**
**Upper and Lower Montney Horizontal Type Curves**




Source: Talisman Energy, Investor Presentation – NAO, May 2008.

The Montney formation has attracted a great deal of attention from major oil and gas companies in recent years. In August 2008, Duvernay Oil Corp., a junior Alberta-based E&P company which owned 450,000 net acres of Montney land, was acquired by Shell Canada for $5.9 billion. EnCana Corp., Talisman Energy, and Murphy Oil are the main players in Montney area, with combined net land holdings of 1.4 million acres.

In 2008, EnCana drilled 82 net wells, and produced 296 MMcf/d (after royalties) from their 962,000 net acre Cutbank Ridge resource play.[52] Land holdings in the Montney formation, part of the Cutbank Ridge play, totaled 730,000 net acres as of February 2009.[53] EnCana's operations in the Swan area target turbidites rather than shale.

Talisman owns on 830,000 net (590,000 gross) acres of Montney land in British Columbia and Alberta.[54] The company's 2009 Montney plans include the completion of 2 pilot projects (Legacy in British Columbia, and Cabin Creek in Alberta), and drilling 49 gross wells.[55]

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[52] EnCana Corp, News Release, February 12, 2009.
[53] China Harbir, and Stacy Knull, EnCana Corp., CIBC World Markets Whistler Institutional Investor Conference, February 19, 2009.
[54] Talisman Energy, A Clear Strategy to Unlock Value, Corporate Presentation February 2009.
[55] Talisman Energy, Investor Presentation – NAO, May 2008

ARC Energy, Storm Exploration, Galleon Energy Inc., Celtic Exploration, Canada Energy Partners, West Energy, Approach Resources, and Sabertooth Energy are among the companies operating in the Montney formation.

The Jean Marie Tight Sands

A large portion of the unconventional gas production in British Columbia is produced from tight gas formations. The Devonian Jean Marie tight gas play, located east of Fort Nelson in the Northern Plains region of British Columbia, is estimated to contain over 5 Tcf of gas in place.[56] Unlike shale gas, producing gas from the Jean Marie requires no water and only moderate fracturing.[57]

Table 5.8 highlights some of the characteristics of the Jean Marie.

**Table 5.8**
**Jean Marie Characteristics**

| Parameter | Jean Marie |
|---|---|
| Resource Range (Bcf/DSU) | 1-10 |
| Prospective Area (acres) | 6,918,951 |
| Reservoir Continuity | Moderate - shelfal carbonates |
| Total Gas Resource Range (Tcf) | 25-100 |

Source: British Columbia Ministry of Energy and Mines.

EnCana is the dominant explorer in the Jean Marie, with rights to 2.4 million net acres of land. The company's Greater Sierra play produces tight gas from the Jean Marie formation using a combination of horizontal and unbalanced drilling techniques.[58] With unbalanced drilling, inert nitrogen foam is used in place of water-based mud in order to improve the productivity of the gas well.[59]

5.4.1.3 Potential Constraints

While the hydrocarbon resources in the Horn River, Montney, and Jean Marie formations are believed to be quite substantial, operators in these resource plays face several constraints. The key constraints faced by producers include, but are not limited to, low gas prices, the short drilling season, the lack of existing infrastructure (pipelines and roadways), produced carbon dioxide ($CO_2$), and emerging water issues.

[56] Tight Gas Potential in Northeast British Columbia", British Columbia Ministry of Energy and Mines, http://www.empr.gov.bc.ca/OG/oilandgas/petroleumgeology/UnconventionalOilAndGas/Documents/tightgas_final.pdf, Accessed on February 24, 2009.
[57] Ibid.
[58] EnCana Corporation, http://www.encana.com/operations/canada/greatersierra/index.htm, Accessed on February 24, 2009.
[59] EnCana Corporation, http://www.encana.com/investors/newsreleases/2002/P1161708944020.html, February 24, 2009.

In its report, Short-term Natural Gas Deliverability 2008-2010, the NEB warns that high costs of production, and soft natural gas prices, could be constraining factors for the development of shale gas in Canada. Early in September 2008, Devon Canada estimated that its acreage in the Horn River Shale holds as much as 8 Tcf of gas reserves, but also warned that high development costs could inhibit efforts to extract it. Apache's President, John Crum, shares this sentiment. In early September Crum stated that costs, combined with decreasing natural gas prices, could be an issue in the remote shale play. Analysts have suggested that gas prices of $6 to $7 per Mcf are needed to make the northeastern British Columbia shale plays economically viable.

Accessing much of the northeastern British Columbia hydrocarbon resources is limited to the winter months (December to March), when the land is in a deep freeze. As the ground thaws, it is unable to sustain the weight of the drilling equipment. As such, both workers and production equipment must be removed before the spring break-up commences. A short drilling season, in turn, places limitations on the amount of natural gas that can be produced in the area.

Over time, we can expect to see improvements in technology that will effectively extend the drilling season in northern climates. In EnCana's Greater Sierra resource play, the company has used wooden mats to allow the completion of multi-well programs during the summer months.[60] The ability to drill multiple horizontal wells (8-20 wells) from a single pad can increase production during a given drilling season, and improve the project economics for companies operating in the region. Nexen is among the companies that will be utilizing multi-well pads in 2009.

Without sufficient pipeline capacity to move gas to markets, much of British Columbia's resources could remain shut-in. Existing pipeline takeaway capacity is likely to be adequate initially, however, as the area develops, additional pipe will be required to tie into major export trunk lines.

TransCanada recently completed two binding open seasons for pipeline capacity from the Horn River and Montney areas to its existing Alberta pipeline network. Shipping contracts have been secured to move 378 MMcf/d of gas on the proposed $340 million Horn River pipeline. The Horn River pipeline is expected to commence operations in the middle of 2011.[61] By the end of 2010, TransCanada's $250 million Groundbirch Pipeline will begin transporting up to 1 Bcf/d of gas from British Columbia's Montney region (northwest of Dawson Creek) to the Alberta system near the Gordonale meter station.[62]

Another noteworthy investment in British Columbia's pipeline infrastructure is the recently approved $1 billion proposal by Pacific Trail Pipelines to construct a pipeline from the Sempra

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[60] EnCana, http://www.encana.com/operations/canada/greatersierra/, Accessed on March 4, 2009.
[61] http://uk.reuters.com/article/oilRpt/idUKN2622905120090226, accessed on March 4, 2009.
[62] TransCanada, Groundbirch Pipeline Project Description Submitted to the National Energy Board, November 2008. https://www.neb-one.gc.ca/ll-eng/Livelink.exe/fetch/2000/90464/90550/90715/518313/541647/541467/A1H9X3_-_Project_Description.pdf?nodeid=541354&vernum=0, accessed on March 4, 2009.

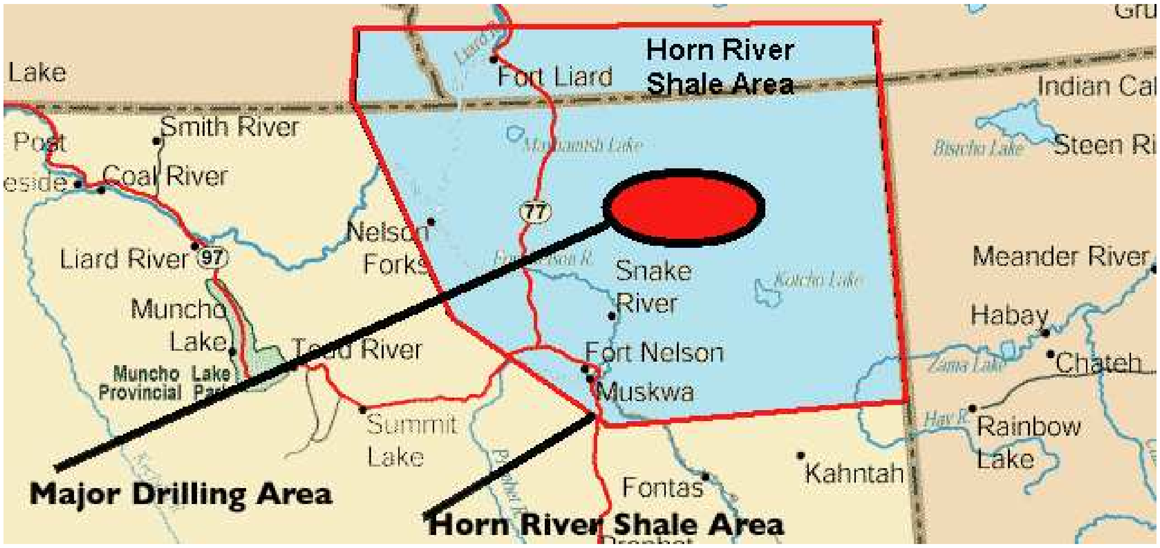
Energy Transmission system at Summit Lake to Kitimat LNG Inc.'s natural gas liquefaction site. The Kitimat to Summit Lake Pipeline Looping Project will be approximately 462 kilometers (287 miles) in length, and have a capacity of 1 Bcf/d. Pipeline construction is slated to begin this year and is anticipated to be complete by 2013. Through Kitimat, northeast British Columbia gas will be transported to Asian markets, where natural gas typically fetches a price premium over the North American market price. The 5 million tonne per year Kitimat LNG, which has already signed a Heads of Agreement with Mitsubishi for 1.5 million tonnes per year, is expected to commence operations in 2013.

The lack of available roadways in northeastern British Columbia makes accessing remote shale areas extremely difficult. As shown in Figure 5.17, Fort Nelson is the largest city center within a relatively close proximity to the Horn River Basin. Before the Montney and Horn River Basin gas can be fully commercialized, government and industry will have to improve the infrastructure in the region.

The Infrastructure Royalty Credit Program, the Heartland Oil and Gas Road Rehabilitation Strategy, and the Public-Private Partnership (P3) for the Sierra-Yoyo-Desan Road, are ways in which the British Columbia government is attempting to promote improvements in regional infrastructure. Announced in March 2009, the British Columbia government plans to spend $187 million over 4 years to upgrade the aforementioned road into the Horn River basin.[63]

63 http://www.ogj.com/display_article/357276/120/ARTCL/none/ExpID/1/British-Columbia/ (March 31, 2009)

**Figure 5.17**
**Horn River Shale Region**




Source: Oilandgasshale.com

Natural gas produced in the Horn River basin consists of 10 percent $CO_2$ or more in some cases. In order for the natural gas to meet pipeline specifications, the $CO_2$ must be removed. Once the $CO_2$ is separated out from the natural gas, it can be disposed of in two ways: injecting it into a suitable reservoir or shipping it through pipelines to be used in Enhanced Oil Recovery (EOR). While both options could prove to be quite costly, utilizing the $CO_2$ in EOR (in either British Columbia or Alberta) may be the more preferred choice, as it will generate an income stream, which would offset some portion of the infrastructure costs. Spectra Energy, in partnership with the British Columbia government, is currently evaluating the technological, geological and economic feasibility of a large-scale Carbon Capture and Storage (CCS) project to be located near the company's existing Fort Nelson gas processing plant.[64]

As production of gas from shale, tight sands, and CBM increases, the strain on existing water resources will become more apparent. The availability of large volumes of water is crucial to northeastern British Columbia's shale development. In 2008, Apache reported using 280,000 barrels of water in 18 fracture stimulations for 3 horizontal Horn River wells.[65] Due to the low permeability inherent in gas shales, sub-surface stimulation is almost always required to fracture the rocks. Using substantial amounts of water and sand, hydraulically fracturing the shale allows the gas to flow to the wellbore.

In neighbouring Alberta, where fresh water concerns are mounting, new technologies and policies are being explored to increase the productivity of fresh water resources. While water is

[64] Spectra Energy, http://www.spectraenergy.com/our_responsibility/climate/carbon_capture/, Accessed on March 4, 2009.
[65] Apache News Release, April 8, 2008. http://investor.apachecorp.com/releasedetail.cfm?ReleaseID=303676, Accessed on February 16, 2009.

more abundant in British Columbia than in Alberta, the successful deployment of new water saving technologies will be crucial to the future development of the province's gas resources.

### 5.4.2 Forecasts

Figures 5.18 and 5.19 represents CERI's view of shale/tight gas resource developments broken down into forecasted new gas well connections and associated non-productive wells that are a typically part of the exploration and development activities. The latter are labeled dead and abandoned wells. These figures also indicate the resulting incremental gas flow rate from the completed gas wells. Figure 5.18 illustrates cumulative investment and incremental flow rates for the Horn River while Figure 5.19 pertains to the Montney.

**Figure 5.18**
**Well Drilling Profile and Incremental Flow Rate for Horn River (25-Year Forecast)**

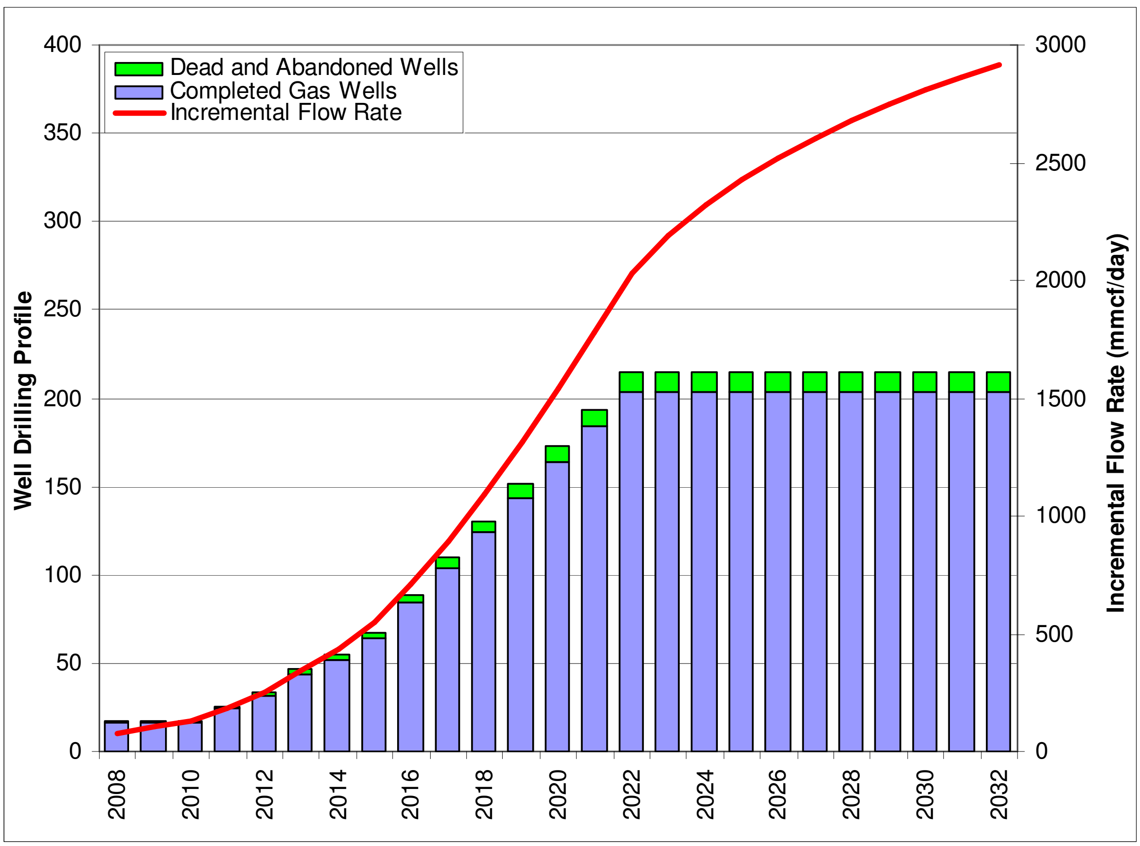
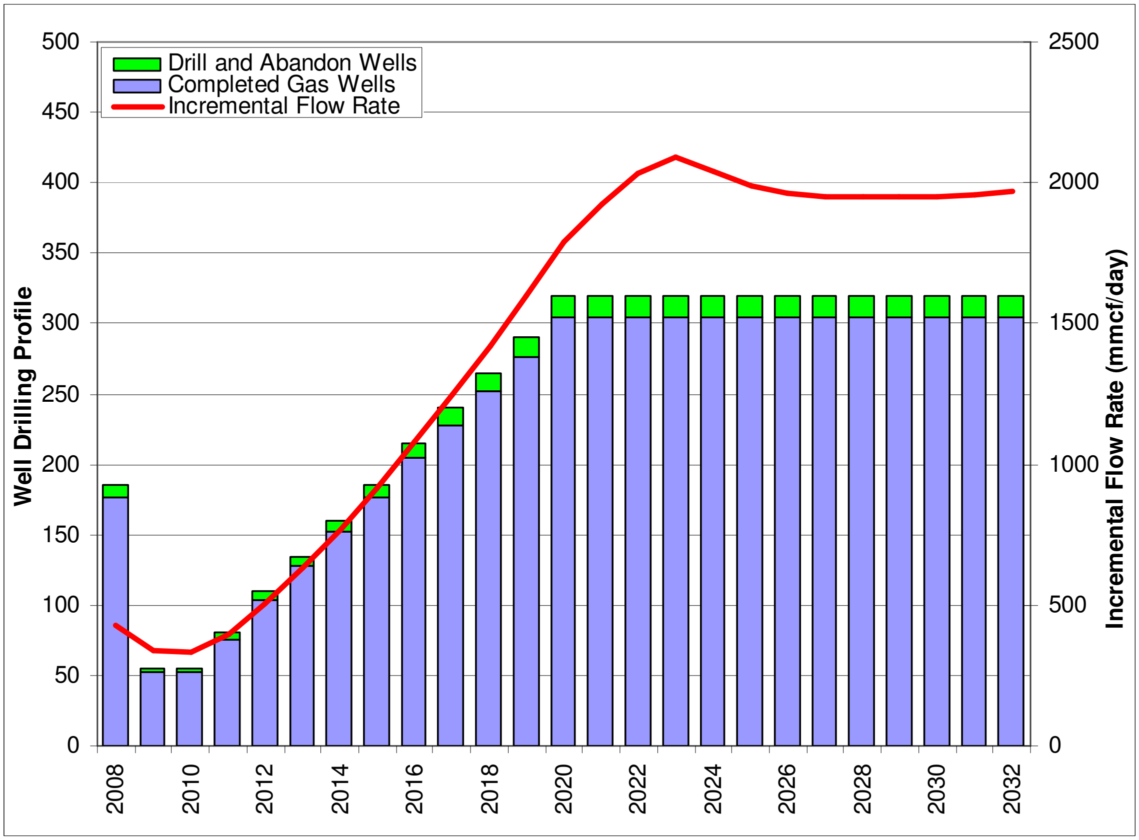


**Figure 5.19**
**Well Drilling Profile and Incremental Flow Rate for Montney (25-Year Forecast)**




### 5.4.3 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Table 5.9 and 5.10, 91 percent of the impacts are directly related to British Columbia, with the remaining 9 percent being felt across the other provinces and territories.

In addition to the economic impacts listed in the tables below, the royalties payable to the province of British Columbia in regard to British Columbia shale/tight gas from Horn River and Montney, over the next 25-years, will be $35,845 million and $31,985 million, respectively. On average, this equates to approximately $2.7 billion per year.

**Table 5.9**
**Impacts Associated with Investment in British Columbia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 1,542 | 19 | 255 | 163 | 93 |
| **British Columbia** | 46,927 | 328 | 12,834 | 6,604 | 6,230 |
| **Manitoba** | 218 | 4 | 70 | 33 | 36 |
| **New Brunswick** | 70 | 1 | 24 | 12 | 12 |
| **Newfoundland & Labrador** | 43 | 1 | 13 | 6 | 8 |
| **Northwest Territories** | 27 | 0 | 7 | 5 | 2 |
| **Nova Scotia** | 96 | 2 | 34 | 16 | 18 |
| **Nunavut** | 6 | 0 | 3 | 3 | 1 |
| **Ontario** | 1,437 | 22 | 372 | 183 | 189 |
| **Prince Edward Island** | 14 | 0 | 6 | 3 | 3 |
| **Quebec** | 695 | 12 | 215 | 93 | 122 |
| **Saskatchewan** | 296 | 5 | 79 | 39 | 40 |
| **Yukon Territory** | 24 | 0 | 11 | 8 | 3 |
| **Canada** | 51,397 | 395 | 13,923 | 7,165 | 6,758 |

**Table 5.10**
**Impacts Associated with Operation in British Columbia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 6,350 | 80 | 1,052 | 670 | 382 |
| **British Columbia** | 193,213 | 1,352 | 52,839 | 27,190 | 25,649 |
| **Manitoba** | 899 | 16 | 287 | 137 | 150 |
| **New Brunswick** | 288 | 6 | 100 | 49 | 50 |
| **Newfoundland & Labrador** | 179 | 4 | 55 | 24 | 32 |
| **Northwest Territories** | 112 | 1 | 28 | 19 | 9 |
| **Nova Scotia** | 397 | 8 | 140 | 66 | 75 |
| **Nunavut** | 27 | 0 | 14 | 10 | 3 |
| **Ontario** | 5,916 | 92 | 1,532 | 752 | 780 |
| **Prince Edward Island** | 57 | 1 | 23 | 11 | 12 |
| **Quebec** | 2,860 | 47 | 886 | 382 | 504 |
| **Saskatchewan** | 1,218 | 20 | 323 | 159 | 164 |
| **Yukon Territory** | 101 | 1 | 45 | 31 | 14 |
| **Canada** | 211,616 | 1,628 | 57,325 | 29,501 | 27,824 |

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 5.20, Alberta receives 35 percent of the impacts, 32 percent for Ontario, 16 percent for Quebec and 7 percent for Saskatchewan. Figures 5.21 and 5.22 show the similar impacts on employment, and federal and provincial taxes.

**Figure 5.20**
**Total GDP Impacts ($million)**

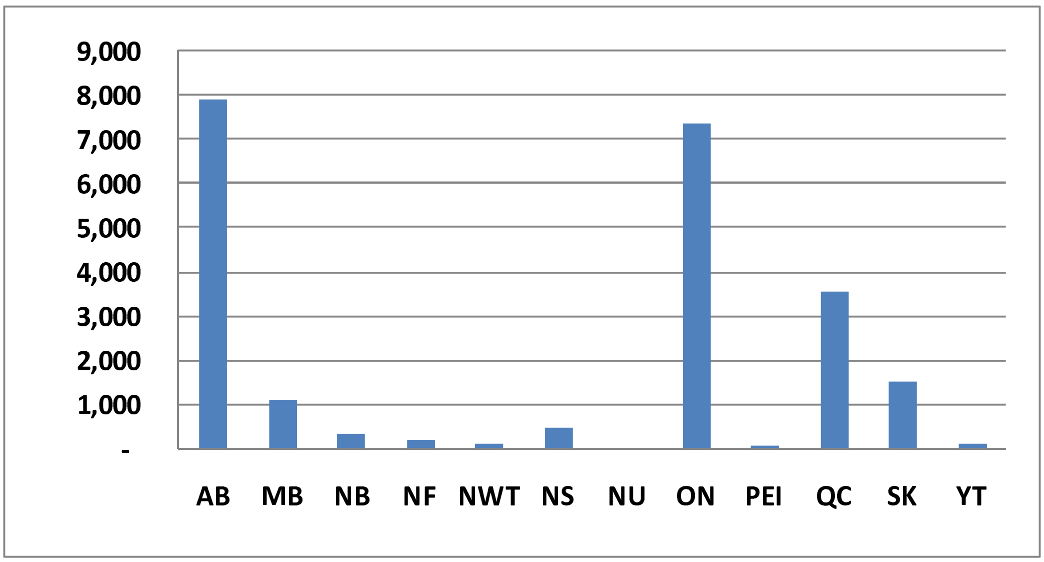



**Figure 5.21**
**Total Employment Impacts (thousand person years)**

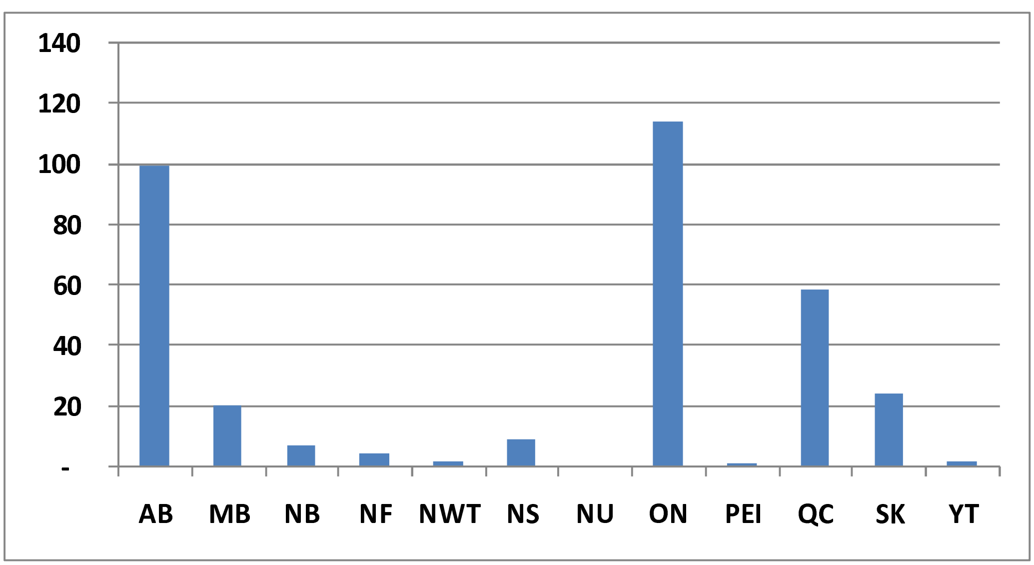
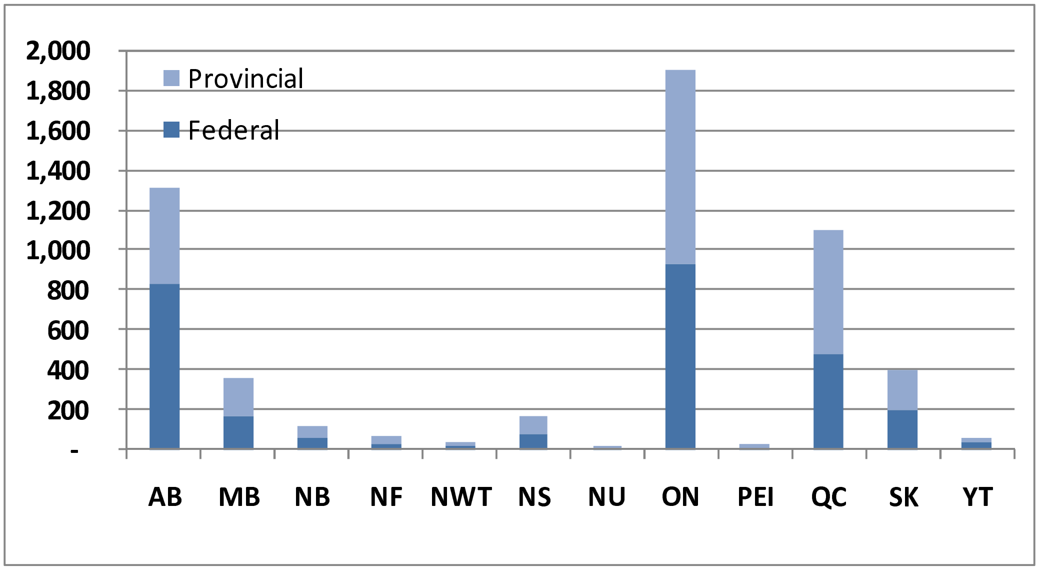


**Figure 5.22**
**Total Federal and Provincial Tax Impacts ($million)**




### 5.5 Major Capital Projects

#### 5.5.1 Background

The following table presents a summary of mid-stream oil and gas projects announced in the province, as of Q1 2009. The table includes a brief description of the projects, its cost and approximate timeline. In the case of British Columbia, this study analyzes separately the economic impacts of the Enbridge Pipeline Gateway project and LNG developments (and accompanying pipelines). The results of the economic impacts for the former are illustrated in Section 5.5.2. The economic impacts for the Kitimat LNG terminal, Kitimat northern Gateway Pipeline and Kitimat to Summit Lake Pipeline are illustrated in Section 5.5.4, following a brief LNG development overview in the province of British Columbia (Section 5.5.3).

**Table 5.11**
**Summary of British Columbia Major Oil and Gas Project Inventory**

| Project Name/Organization | Description | Cost ($million) | Time Duration |
|---|---|---|---|
| Texada Island LNG Terminal 1 | New LNG terminal and gas-fired plant | 2,000 | 2010-014 |
| Terasan LNG Gas System upgrades | Develop storage facility and add pipeline distribution system | 32 | 2008- 2009 |
| Kitimat Northern Gateway Pipeline Condensate Pipeline | Proposed pipeline from Kitimat to Edmonton | 2,500 | 2012-2015 |
| Kitimat<br>Kitimat LNG Terminal | Construction of a marine terminal in Kitimat and a 465 km pipeline | 3,000 | 2008-2010 |
| Kitimat<br>The Spirit Pipeline - TMX North Project | Pipeline project to move 100,000 bpd of condensate from Valemount to Kitimat. | 2,500 | |
| Kitimat to Summit Lake Pipeline<br>Pembina Pipeline Corp. | LNG at Bish Cove to deliver natural gas into the Pacific Natural Gas (PNG) pipeline. | 1,200 | 2009-2011 |
| Kitimat Northern Gateway Pipeline Project - Crude Oil Pipeline | Proposed bitumen export pipeline from Edmonton to deliver crude oil to deep water port at Kitimat. | 1,900 | |
| Kitimat To Summit Lake<br>KSL Pipeline Project | Construction of a new 500 km, 24 inch natural gas pipeline between Summit Lake and Kitimat BC | N/A | 2009-2010 |
| Fort Nelson Cabin Gas Plant<br>EnCana Corporation | Facility for processing natural gas from the Horn River Basin | 400 | |
| Fort St. John To Taylor<br>South Peace Pipeline<br>Spectra Energy Corp. | 85 km gas pipeline from Fort St. John to McMahon processing plant (Taylor) | 100 | 2009 |
| Groundbirch Pipeline<br>TransCanada Pipelines | 77 km natural gas pipeline from Alberta to Groundbirch, BC | 75 | 2009-2010 |
| Whistler Natural Gas Pipeline Terasen Pipelines Inc. | 20 cm natural gas pipeline from Terasen to Whistler. | 37 | 2006-2009 |

Source: BC: British Columbia Major Projects Inventory, Ministry of Small Business, Technology and Economic Development, Dec 2008.

### 5.5.2 Economic Impacts (Gateway Pipeline)

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 5.12 and 5.13, 80 percent of the impacts are directly related to British Columbia, with the remaining 20 percent being felt across the other provinces and territories.

**Table 5.12**
**Impacts Associated with Investment in British Columbia**

| | $ million | Thousand Person Years | | $ million | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 115 | 2 | 19 | 12 | 7 |
| **British Columbia** | 2,155 | 37 | 589 | 303 | 286 |
| **Manitoba** | 19 | 0 | 6 | 3 | 3 |
| **New Brunswick** | 6 | 0 | 2 | 1 | 1 |
| **Newfoundland & Labrador** | 4 | 0 | 1 | 0 | 1 |
| **Northwest Territories** | 2 | 0 | 1 | 0 | 0 |
| **Nova Scotia** | 8 | 0 | 3 | 1 | 2 |
| **Nunavut** | 1 | 0 | 0 | 0 | 0 |
| **Ontario** | 119 | 2 | 31 | 15 | 16 |
| **Prince Edward Island** | 1 | 0 | 0 | 0 | 0 |
| **Quebec** | 60 | 1 | 19 | 8 | 11 |
| **Saskatchewan** | 24 | 0 | 6 | 3 | 3 |
| **Yukon Territory** | 2 | 0 | 1 | 1 | 0 |
| **Canada** | 2,516 | 43 | 679 | 349 | 330 |

**Table 5.13**
**Impacts Associated with Operation in British Columbia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 288 | 4 | 48 | 30 | 17 |
| **British Columbia** | 3,062 | 51 | 837 | 431 | 407 |
| **Manitoba** | 57 | 1 | 18 | 9 | 9 |
| **New Brunswick** | 15 | 0 | 5 | 3 | 3 |
| **Newfoundland & Labrador** | 9 | 0 | 3 | 1 | 2 |
| **Northwest Territories** | 5 | 0 | 1 | 1 | 0 |
| **Nova Scotia** | 20 | 0 | 7 | 3 | 4 |
| **Nunavut** | 2 | 0 | 1 | 1 | 0 |
| **Ontario** | 355 | 6 | 92 | 45 | 47 |
| **Prince Edward Island** | 3 | 0 | 1 | 1 | 1 |
| **Quebec** | 144 | 3 | 45 | 19 | 25 |
| **Saskatchewan** | 63 | 1 | 17 | 8 | 9 |
| **Yukon Territory** | 6 | 0 | 2 | 2 | 1 |
| **Canada** | 4,029 | 67 | 1,078 | 554 | 524 |

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 5.23, Ontario receives 36 percent of the impacts, 30 percent for Alberta, 16 percent for Quebec and 7 percent for Saskatchewan. Figures 5.24 and 5.25 show the similar impacts on employment, and federal and provincial taxes.

**Figure 5.23**
**Total GDP Impacts ($million)**

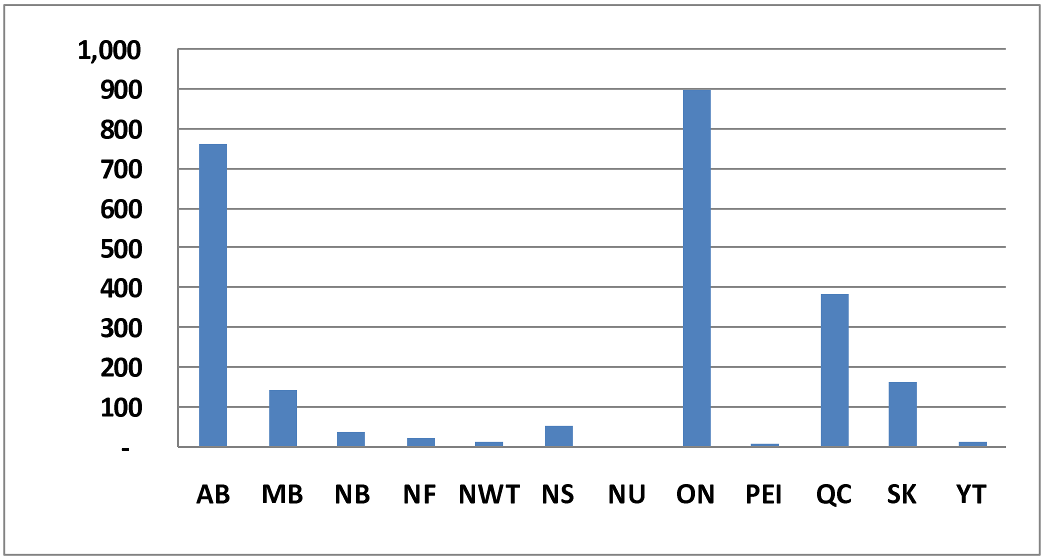



**Figure 5.24**
**Total Employment Impacts (thousand person years)**

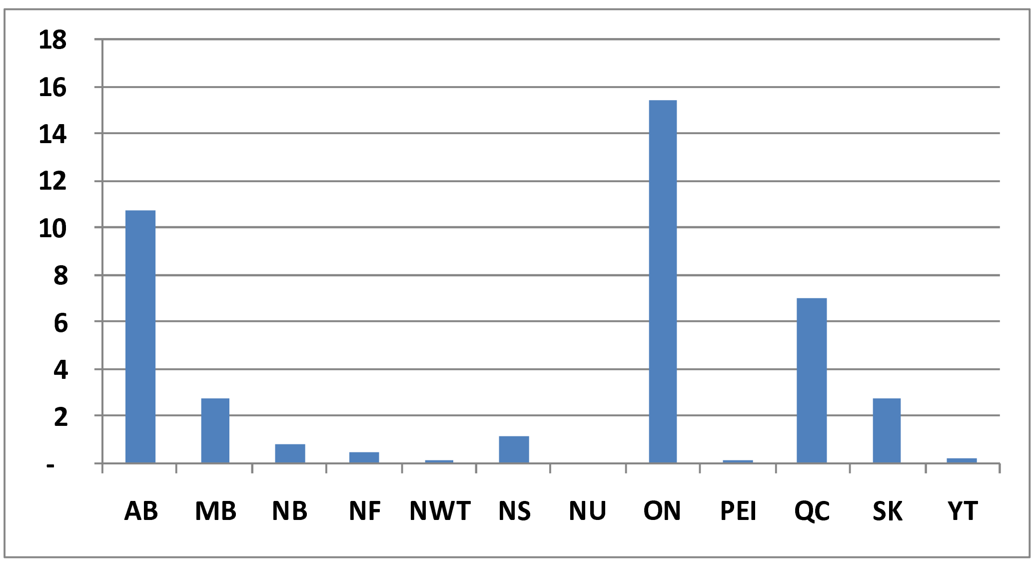
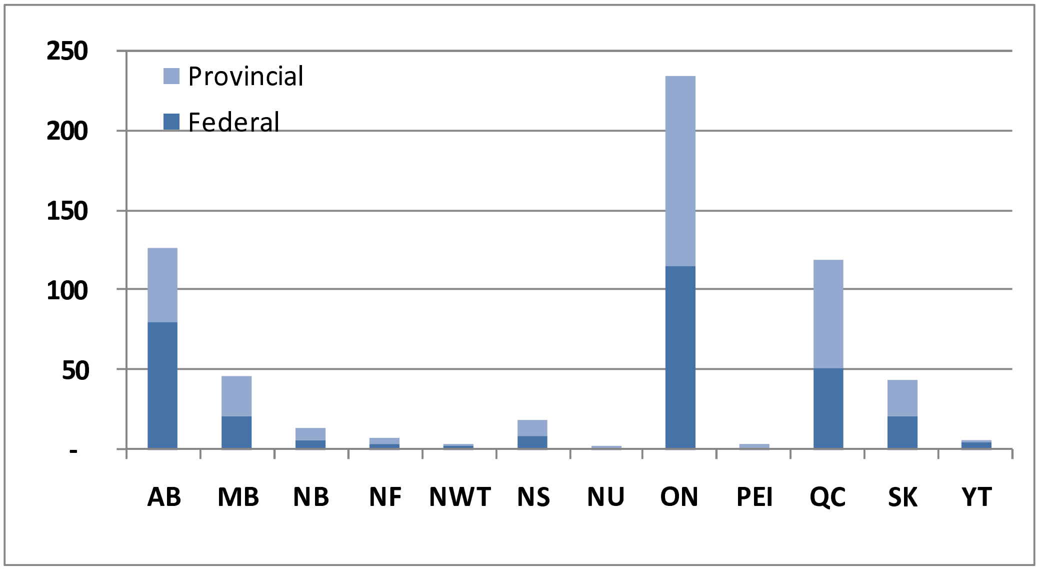


**Figure 5.25**
**Total Federal and Provincial Tax Impacts ($million)**




### 5.5.3 LNG Development

5.5.3.1 Background

LNG is simply natural gas that has been cooled to the point where it condenses into its liquid state. The four main components of the LNG supply cost chain are, exploration and production, liquefaction, shipping, and re-gasification (including onshore storage). Liquefaction and re-gasification are discussed briefly, as both facilities are being proposed in British Columbia. It is important to identify that some of the proposed projects may be mutually exclusive, as the simultaneous operation of re-gasification and gasification terminals may be economically awkward.

<u>Liquefaction</u>

LNG is natural gas that has been cooled to the point when it condenses into its liquid state. This occurs at -163° Celsius (-260° Fahrenheit) and at atmospheric pressure. In its liquid state, natural gas occupies only one six-hundredth of its gaseous volume. This makes it economical to transport between continents and over long distances in specially designed LNG tankers.

In addition, LNG becomes a clear, colourless, odourless liquid that weighs slightly less than half as much as water. It is the same natural gas that many North Americans use in their homes, except in liquid form.

Feed gas to the liquefaction plant comes from the production field. The contaminants found in produced natural gas are removed to avoid freezing up and damaging equipment when the gas is cooled to LNG temperature. Current suppliers deliver gas with the heat content in the range of

980-1,080 Btu/cf, which meets North American pipeline specifications. LNG with Btu value in excess of 1,080, exceeds North American pipeline specifications because it contains almost no inert gases, such as $CO_2$ and $N_2$ and more non-methane hydrocarbons, such as ethane, propane and butanes, than historical US supplies.

Re-gasification

To return LNG to a gaseous state, it is fed into a re-gasification plant. On arrival at the receiving terminal in its liquid state, LNG is pumped first to a double-walled storage tank, similar to those used in the liquefaction plant, at atmospheric pressure, then pumped at high pressure through various terminal components where it is warmed in a controlled environment.

LNG could also be pumped directly from the LNG ship to the pipelines without a storage tank. Then LNG is warmed by passing it through pipes heated by direct-fired heaters, seawater, or through pipes that are in heated water.[66] The vapourized gas is then compressed up to line pressure and enters the pipeline system as natural gas. Finally, residential and commercial consumers receive natural gas for daily use from local gas utilities or in the form of electricity.

5.5.3.2 Terminal Development

There are three LNG developments in British Columbia, one of which is very recent. This section will review Kitimat LNG, WestPac LNG and Teekay FLNG. Both Kitimat and Teekay proposals are export terminals and located in close proximity to each other; the difference being Teekay proposes a floating LNG terminal. WestPac, on the other hand, is an import facility.

Kitimat LNG – Kitimat (Export Terminal)

Kitimat LNG Inc has expressed interest in building a natural gas liquefaction facility 15 km from Kitimat, British Columbia. The planned LNG export terminal will be the first of its kind in North America since Alaska's Kenai plant began operating in 1969. The plant will access natural gas mostly from the unconventional gas sources from the Horn River and Montney area in British Columbia, in addition to gas from the WCSB.[67] Approvals from the Federal government of Canada and the Provincial Government of British Columbia were received in the beginning of 2009.[68] The export facility is now in the process of completing the front-end engineering and design to initiate the construction phase, scheduled to begin in 2010.

The facility is estimated to cost approximately $3 billion and will have a send-out capacity of 5 million tons of LNG per year. Approximately 4 to 5 shipments will be sent out each year to meet

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[66] Federal Energy Regulatory Commission (FERC) views seawater racks as potentially harmful to the sea life. Terminals planning on using this technology have been put on hold pending an environmental assessment.

[67] Preliminary Information Document, December 2008: http://www.kitimatlng.com/upload/documents/pdf/RequestExpressInt_Nov08.pdf

[68] Approval from the Canadian Federal Government was received December 10, 2008 while approval from B.C Provincial Government was received January 9, 2009

demand in the Pacific Rim LNG market. The Asia Pacific region currently is the largest consumer of LNG, represented mostly by Japan (48 percent of total LNG imports) and South Korea (15 percent).[69]

Galveston LNG spearheads the project and its subsidiaries include Kitimat LNG Inc, one of the two wholly-owned subsidiaries of Galveston LNG Inc who are committed to developing, constructing and operating the LNG terminal. Pacific Trail Pipeline will be responsible for building the transmission pipeline system to deliver gas from Summit Lake to Kitimat, British Columbia. As for the marketing and trading aspect of the terminal's LNG production, LNG IMPEL, the other wholly-owned subsidiary of Galveston, has expressed interest in carrying out this duty.

By mid-January of 2009, Mitsubishi Corporation announced that it acquired an equity stake in Kitimat's LNG facility. Mitsubishi also signed a Heads of Agreement contract with Kitimat LNG Inc committing to the purchase of 1.5 million tons per year of the LNG produced from the terminal.[70]

WestPac Terminal – Texada Island (Import Terminal)

The WestPac Corporation is planning on building a LNG import terminal along with a power generation facility in Texada Island, British Columbia. The facility is to be located between Vancouver Island and the mainland, north of Vancouver. The terminal anticipates receiving up to 36 LNG carriers every year from various locations such as South Asia, the Pacific Rim and the Middle East.[71] It is expected to include two LNG storage tanks with a gross capacity of 165,000 $m^3$ each and a re-gasification unit with a capacity of 500 MMcf/d.

In addition, the power generation facility, which will include natural gas-fired turbines and heat-recovery steam generators, will be used to aid the supply of electricity from the B.C. mainland to Vancouver Island. The LNG re-gasification terminal and the power generator unit will be positioned strategically in order for the waste heat produced by the power generator turbines to be used in the re-gasification process to minimize power usage.[72]

Currently, WestPac LNG is preparing a detailed project description to be filed to the BC Environmental Assessment Office and The Canadian Environmental Assessment Agency to start the necessary regulatory and environmental assessment process and public consultation.[73] Provided the project clears regulatory and environmental assessments, it is expected to come online in 2014.

[69] "North American Terminal Survey" (NATS), prepared by Pan EuroAsian Enterprises, Inc., version 7, August 2005.
[70] Kitimat LNG Inc Media Center: http://www.kitimatlng.com/code/navigate.asp?Id=32
[71] WestPac LNG - Texada Island Terminal: http://www.westpaclng.com/index.php?pageId=Texada+Island+Terminal
[72] Ibid
[73] WestPac LNG Company Overview: http://www.westpaclng.com/index.php?pageId=Company+Overview

Teekay FLNG – near Kitimat (Export Terminal)

The Teekay FLNG is the newest proposal, announced in Mid-March 2009, in Canada. Teekay Corp. and Merrill Lynch Commodities have announced a joint bid to convert the S/S Arctic Spirit into a floating LNG facility.[74] The facility, located near Kitimat, BC, will have the production capacity to liquefy 75-100 MMcf/d.

According to the company's website, the project is expected to commence operation in 2012. This is subject to obtaining the necessary regulatory approvals.

### 5.5.4 Economic Impacts (LNG)

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 5.14 and 5.15, 79 percent of the impacts are directly related to British Columbia, with the remaining 21 percent being felt across the other provinces and territories.

**Table 5.14**
**Impacts Associated with Investment in British Columbia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 201 | 3 | 33 | 21 | 12 |
| **British Columbia** | 3,756 | 64 | 1,027 | 529 | 499 |
| **Manitoba** | 33 | 1 | 11 | 5 | 6 |
| **New Brunswick** | 11 | 0 | 4 | 2 | 2 |
| **Newfoundland & Labrador** | 6 | 0 | 2 | 1 | 1 |
| **Northwest Territories** | 4 | 0 | 1 | 1 | 0 |
| **Nova Scotia** | 14 | 0 | 5 | 2 | 3 |
| **Nunavut** | 1 | 0 | 0 | 0 | 0 |
| **Ontario** | 207 | 3 | 54 | 26 | 27 |
| **Prince Edward Island** | 2 | 0 | 1 | 0 | 0 |
| **Quebec** | 105 | 2 | 33 | 14 | 18 |
| **Saskatchewan** | 41 | 1 | 11 | 5 | 6 |
| **Yukon Territory** | 4 | 0 | 2 | 1 | 1 |
| **Canada** | 4,385 | 74 | 1,183 | 608 | 575 |

[74] http://www.teekay.com/index.aspx?page=news_releases&article_id=566 (March 31, 2009)

**Table 5.15**
**Impacts Associated with Operation in British Columbia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 562 | 8 | 93 | 59 | 34 |
| **British Columbia** | 5,971 | 99 | 1,633 | 840 | 793 |
| **Manitoba** | 110 | 2 | 35 | 17 | 18 |
| **New Brunswick** | 29 | 1 | 10 | 5 | 5 |
| **Newfoundland & Labrador** | 17 | 0 | 5 | 2 | 3 |
| **Northwest Territories** | 10 | 0 | 2 | 2 | 1 |
| **Nova Scotia** | 40 | 1 | 14 | 7 | 7 |
| **Nunavut** | 3 | 0 | 2 | 1 | 0 |
| **Ontario** | 693 | 12 | 179 | 88 | 91 |
| **Prince Edward Island** | 6 | 0 | 2 | 1 | 1 |
| **Quebec** | 280 | 5 | 87 | 37 | 49 |
| **Saskatchewan** | 124 | 2 | 33 | 16 | 17 |
| **Yukon Territory** | 11 | 0 | 5 | 3 | 2 |
| **Canada** | 7,856 | 131 | 2,101 | 1,079 | 1,022 |

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 5.26, Ontario receives 36 percent of the impacts, 30 percent for Alberta, 15 percent for Quebec and 7 percent for Saskatchewan. Figures 5.27 and 5.28 show the similar impacts on employment, and federal and provincial taxes.

**Figure 5.26**
**Total GDP Impacts ($million)**

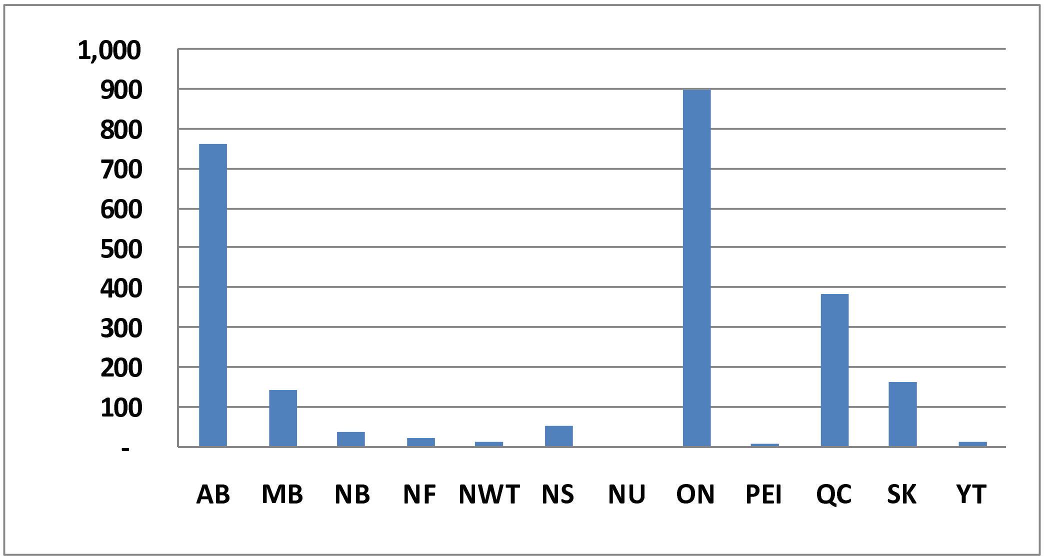



**Figure 5.27**
**Total Employment Impacts (thousand person years)**

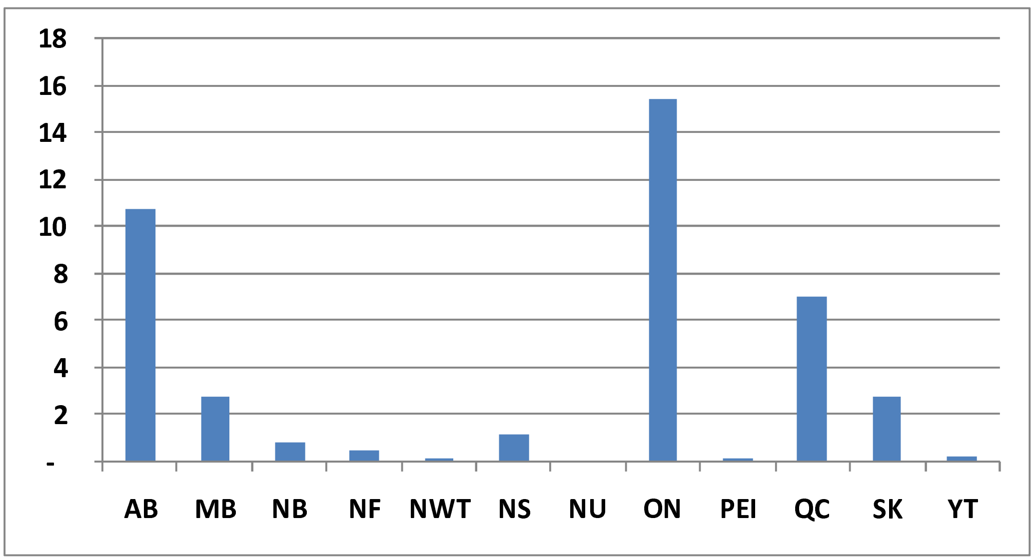
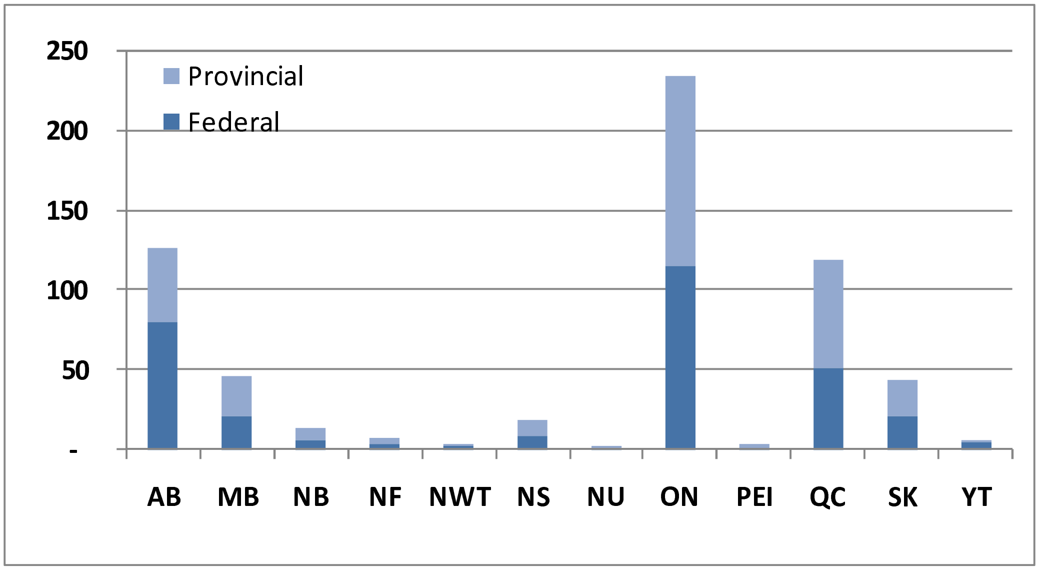


**Figure 5.28**
**Total Federal and Provincial Tax Impacts ($million)**



# CHAPTER 6
# ECONOMIC IMPACTS: SASKATCHEWAN

This chapter discusses the economic impacts for the province of Saskatchewan. Like Alberta, it is divided into six sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Saskatchewan. The following five sections discuss and review the economic impacts of conventional oil resources, conventional gas resources, unconventional gas resources, oil sands resources and major capital projects in the province. Each section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 6.1 Background

This section describes the reserves, productions, and expenditures of the petroleum industry in the province of Saskatchewan. In this section, the methodology that has been used for regrouping components of petroleum industry's expenditures, and their disaggregation into oil and natural gas is demonstrated.

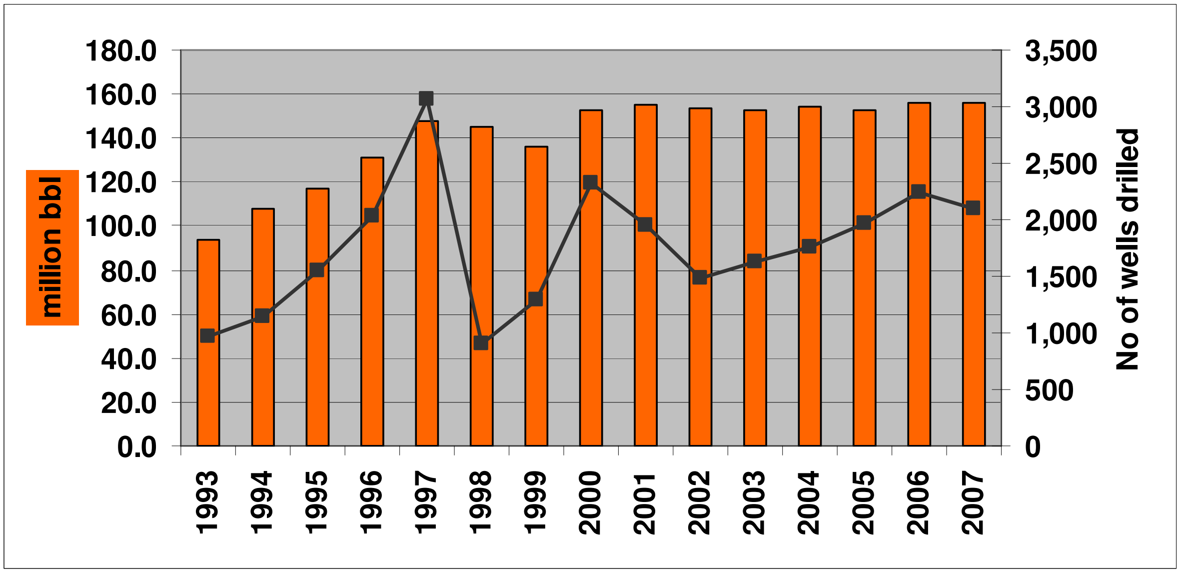
### 6.1.1 Reserves and Production

According to CAPP, as of December 2006, the remaining established reserves of crude oil in Saskatchewan are estimated 1,129 million bbl. This is a net decrease of almost 9 percent from 2005.

Crude oil production in this province has remained somewhat level since 2000, in the range of 153 to 156 million bbl. Production is up from 1993 levels. From 1993 to 2007, Saskatchewan's crude oil production increased on an average annual rate of 3.6 percent. Crude oil production and number of wells drilled are illustrated in Figure 6.1. In Saskatchewan, the number of oil wells drilled increased from 962 wells in 1993, peaked at 3,059 in 1997 and declined thereafter to 2,099 wells in 2007.

The crude oil reserves production ratio is approximately 7.5 years.

**Figure 6.1**
**Saskatchewan Crude Oil Production and Number of Wells Drilled**
**1993 - 2007**



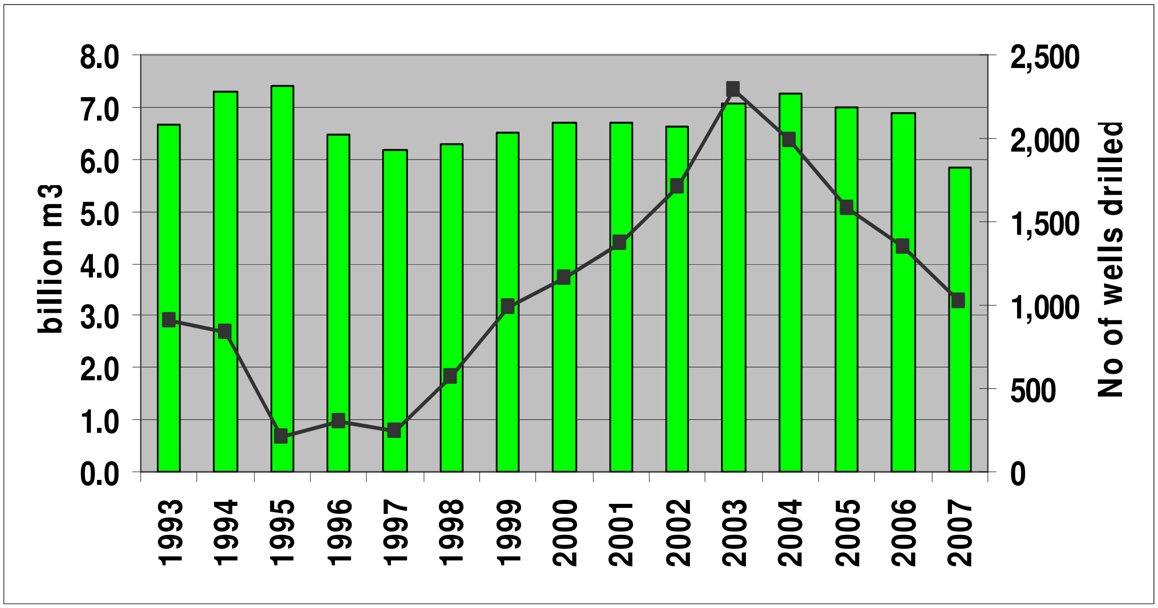

Source: CAPP, Statistical Handbook, September 2008.

According to CAPP, as of December 2006, the remaining established reserve of marketable natural gas was 98.8 billion cubic meters, an increase of almost 7.2 billion $m^3$ from the previous year.

Figure 6.2 illustrates marketable natural gas production and the number of wells drilled between 1993 and 2007. Marketable natural gas production in Saskatchewan decreased from 6.7 billion $m^3$ in 1993 to 5.9 billion $m^3$ in 2007, representing average annual decline rate of less than one percent. Over the same time period the number of gas wells drilled increased from 906 wells in 1993 to 1,023 wells in 2007. The number of gas wells peaked at 2,287 in 2003.

The natural gas reserves production ratio is about 17 years.

**Figure 6.2**
**Saskatchewan Marketable Natural Gas Production and Number of Wells Drilled**
**1993 - 2007**




Source: CAPP, Statistical Handbook, September 2008.

### 6.1.2 Expenditures of the Petroleum Industry in Saskatchewan

The CAPP[75] reports the net cash expenditures[76] of British Columbia petroleum industry for exploration, development, operating and royalties as follows:

A- Exploration
  - A1- Geological & Geophysical
  - A2- Drilling
  - A3- Land

B- Development
  - B1- Drilling
  - B2- Field Equipment
  - B3- EOR
  - B4- Gas Plant

C- Operating
  - C1- Wells & Flow lines
  - C2- Gas Plants

D- Royalties

---

[75] CAPP - TECHNICAL REPORT, Statistical Handbook, For Canada's Upstream Petroleum Industry, September 2008, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=132330
[76] Net cash expenditure exclude inter-industry transactions

The Canadian Association of Petroleum Producers also reports that in 2007, $6.46 billion dollars were spent by the petroleum industry in Saskatchewan. The largest investment expenditures were for development, approximately 37 percent. Operating, royalties and exploration follow at 29 percent, 22 percent and 12 percent, respectively.

Table 6.1 summarizes the methodology, which will be referred to in later sections, that has been used for regrouping the components of petroleum expenditures to the following: drilling investment expenditure, field equipment investment expenditure and operating expenditure.

**Table 6.1**
**Disaggregation of Oil and Gas Expenditures**

| Crude Oil | Natural Gas |
|---|---|
| Drilling Expenditure:<br>A1 + A2 + B1 | Drilling Expenditure:<br>A1 + A2 + B1 |
| Field Equipment Expenditure:<br>B2 + B3 | Field Equipment Expenditure:<br>B2 + B4 |
| Operating Expenditure:<br>C1 | Operating Expenditure:<br>C1 + C2 |

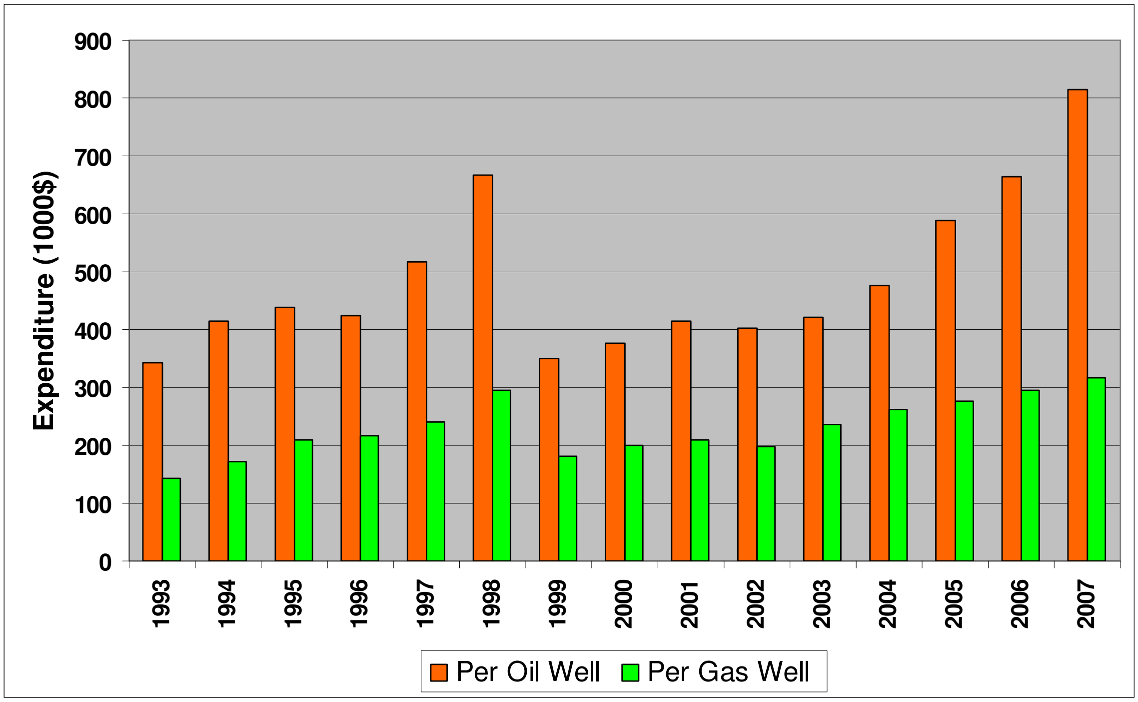
Drilling Investment Expenditure

In 2007, Saskatchewan drilled 3,122 oil and gas wells, of which approximately 67 percent were oil. In the same year, total depth of drilled wells was 4.3 million meters. The share of oil wells was approximately 84 percent.

Between 1955 and 2007, CAPP reports a total of 51,732 oil wells drilled and 22,233 gas wells drilled in Saskatchewan. Drilling expenditures of the petroleum industry (recall A1, A2, and B1 from the previous chapter/section), are taken from CAPP's Statistical Handbook, released in September 2008. These expenditures are disaggregated into oil and gas in proportion to meters oil and gas drilled wells.

Figure 6.3 shows that, over the 1993-2007 period, drilling investment per well was greater for oil than for natural gas. The same graph shows that in 2007, drilling investment was approximately $815,000 per oil well and $316,000 per gas well. Both are at record levels for the province.

**Figure 6.3**
**Saskatchewan Oil and Gas Drilling Investment per Well Drilled**
**1993 - 2007**



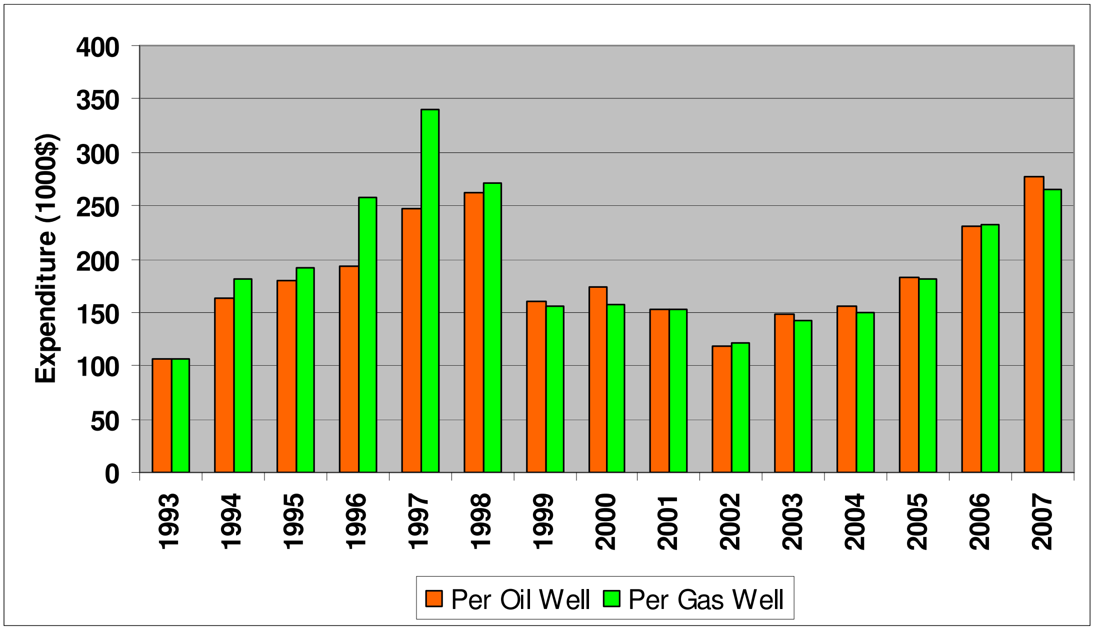

Source: CAPP, Statistical Handbook, September 2008.

Field Investment Expenditure

A major part of field equipment expenditures results from field facilities, crude oil battery and gathering systems. CAPP reports combined oil and gas field equipment expenditure (B2). CERI has disaggregated the above expenditures into oil and gas in proportion to the number of wells drilled. EOR expenditure (B3) was added to oil field investment; similarly, gas plant expenditure (B4) was added to the gas field investment (Recall Table 1.1 from the previous chapter/section).

It should be noted that from 1998 to 2007, field investment per oil and gas wells were almost identical. In 2007, field investment per oil well was approximately $278,000 and per gas well was $265,000, as illustrated in Figure 6.4. Both oil and gas field investment per well drilled has increased every year since 2002.

**Figure 6.4**
**Saskatchewan Oil and Gas Field Investment per Well Drilled**
**1993-2007**

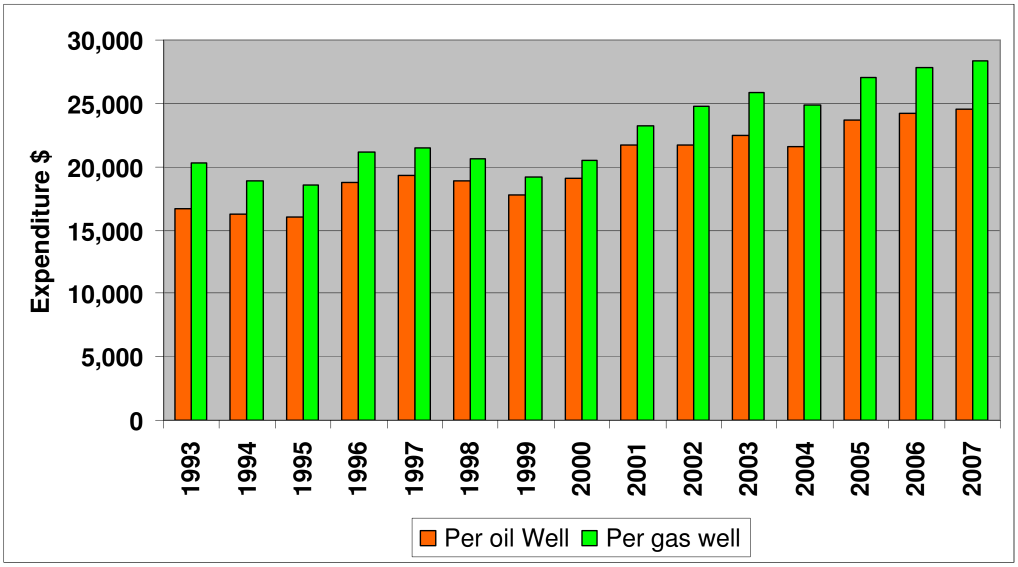



Source: CAPP, Statistical Handbook, September 2008.

<u>Operating Expenditure</u>

To estimate per well operating expenditures, CERI assumes that "wells and flow lines" operating expenditures (C1) for oil and gas are the same, and therefore divides C1 by the total cumulative combined oil and gas wells drilled. Gas plant operating expenditures (C2) per cumulative well is added to the operating expenditure of gas wells. This is illustrated in Figure 6.5.

**Figure 6.5**
**Saskatchewan Oil and Gas Operating Expenditures per Cumulative Successful Well**
**1993-2007**




Source: CAPP, Statistical Handbook, September 2008.

From 1993 to 2007, operating expenditures per gas well were higher than those of oil. In 2007, operating expenditures per cumulative successful oil well were approximately $24,500 and gas well was $28,300.

## 6.2 Conventional Oil Resources

### 6.2.1 Background

Saskatchewan's first commercial oil well was drilled in 1944 in the west central region and initial discoveries and development in the rest of Saskatchewan's oil producing regions occurred in the early 1950s. By the end of decade, Saskatchewan became a significant producer of crude oil. Saskatchewan produces a range of different types of oil with significant light crude oil production in the southeast and medium crude oil production in the southwestern part of the province.[77] Heavy crude oil production represents nearly half of Saskatchewan oil output.

Figure 6.6 illustrates Saskatchewan's conventional oil deposits.[78]

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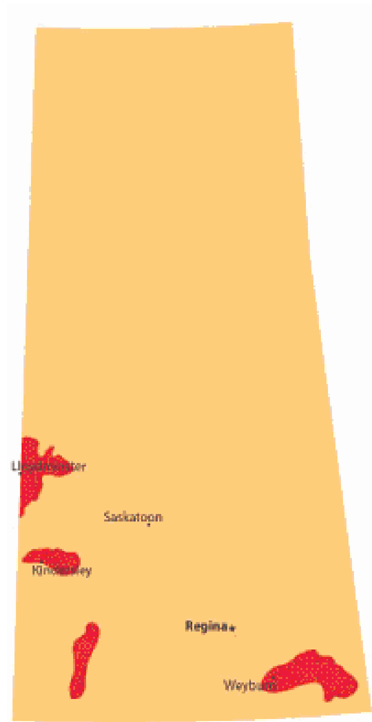
[77] Government of Saskatchewan Energy and Resources, Oil and Gas Summaries, *Crude Oil in Saskatchewan.*
http://www.ir.gov.sk.ca/adx/aspx/adxGetMedia.aspx?DocID=6552,3384,5460,2936,Documents&MediaID=20542&Filename=Fact+Sheet+-+Oil+in+Sask+(Sept+8+2008).pdf
[78] Centre for Energy, *Saskatchewan Energy Facts & Statistics*.

**Figure 6.6**
**Oil Reserves in Saskatchewan**




Source: Centre for Energy.

In 2007, total conventional oil production in Saskatchewan was 24.8 million $m^3$ from 24,900 wells.[79] This ranks Saskatchewan as the second largest oil producer in Canada behind Alberta, and represented 27.3 percent of Canada's total oil production in 2007. At the end of 2006, recoverable reserves of conventional oil were estimated to be 187 million $m^3$.[80]

Drilling in the province slowed slightly in 2007 to 3,112, although the number remains higher than the yearly averages from 1999 to 2006.[81]

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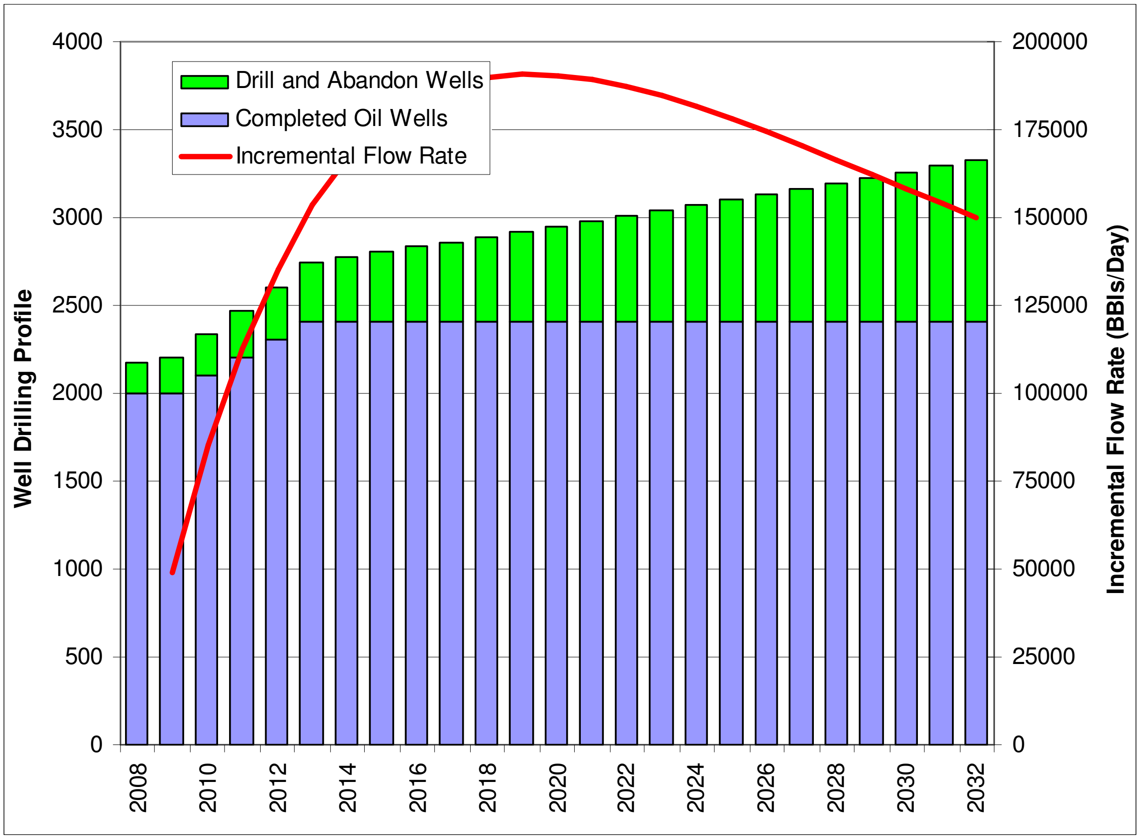
[79] Canadian Association of Petroleum Producers, Industry Facts and Information, Saskatchewan. *2007 Statistics*. http://membernet.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=34092 and Centre for Energy, *Saskatchewan Energy Facts & Statistics*.
[80] Government of Saskatchewan, *Crude Oil in Saskatchewan*
[81] Government of Saskatchewan, *Crude Oil in Saskatchewan*

### 6.2.2 Forecasts

Figure 6.7 represents CERI's view of conventional oil resource developments broken down into forecasted new oil well connections and associated non-productive wells that are a typically part of the exploration and development activities. The latter are labeled dead and abandoned wells. This figure also indicates the resulting incremental oil flow rate from the completed oil wells. It is important to note that the following figure is represents all oil resources, including conventional and the Bakken oil shale. For a description of the Bakken oil shale resources, refer to Section 6.4.

**Figure 6.7**
**Well Drilling Profile and Incremental Flow Rate in Saskatchewan (25-Year Forecast)**




### 6.2.3 Economic Impacts

As mentioned above, the economic impacts include conventional and the Bakken oil shale. For a description of the Bakken oil shale resources, refer to Section 6.4.

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 6.2 and 6.3, 80 percent of the impacts are directly related to Saskatchewan, with the remaining 20 percent being felt across the other provinces and territories.

**Table 6.2**
**Impacts Associated with Investment in Saskatchewan**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 4,694 | 39 | 778 | 495 | 282 |
| **British Columbia** | 2,483 | 30 | 679 | 349 | 330 |
| **Manitoba** | 2,146 | 30 | 685 | 327 | 358 |
| **New Brunswick** | 123 | 3 | 43 | 21 | 21 |
| **Newfoundland & Labrador** | 98 | 2 | 30 | 13 | 17 |
| **Northwest Territories** | 67 | 0 | 17 | 11 | 6 |
| **Nova Scotia** | 130 | 3 | 46 | 21 | 24 |
| **Nunavut** | 11 | 0 | 6 | 4 | 1 |
| **Ontario** | 5,379 | 78 | 1,393 | 684 | 709 |
| **Prince Edward Island** | 21 | 0 | 8 | 4 | 4 |
| **Quebec** | 1,049 | 18 | 325 | 140 | 185 |
| **Saskatchewan** | 64,948 | 465 | 17,239 | 8,473 | 8,766 |
| **Yukon Territory** | 11 | 0 | 5 | 3 | 2 |
| **Canada** | 81,161 | 667 | 21,254 | 10,547 | 10,707 |

**Table 6.3**
**Impacts Associated with Operation in Saskatchewan**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 6,114 | 50 | 1,013 | 645 | 368 |
| **British Columbia** | 3,233 | 39 | 884 | 455 | 429 |
| **Manitoba** | 2,795 | 39 | 892 | 426 | 466 |
| **New Brunswick** | 161 | 3 | 56 | 28 | 28 |
| **Newfoundland & Labrador** | 128 | 2 | 40 | 17 | 23 |
| **Northwest Territories** | 87 | 1 | 22 | 15 | 7 |
| **Nova Scotia** | 169 | 3 | 60 | 28 | 32 |
| **Nunavut** | 14 | 0 | 7 | 6 | 2 |
| **Ontario** | 7,006 | 101 | 1,814 | 891 | 924 |
| **Prince Edward Island** | 27 | 1 | 11 | 5 | 6 |
| **Quebec** | 1,366 | 23 | 423 | 183 | 241 |
| **Saskatchewan** | 84,594 | 606 | 22,454 | 11,036 | 11,418 |
| **Yukon Territory** | 14 | 0 | 6 | 4 | 2 |
| **Canada** | 105,710 | 869 | 27,682 | 13,737 | 13,945 |

In addition to the economic impacts listed in the previous tables, the royalties payable to the province of Saskatchewan in regard to Saskatchewan conventional oil, over the next 25-years, will be $39,752 million. On average, this equates to approximately $1.6 billion per year.

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 6.8, Ontario receives 33 percent of the impacts, 29 percent for Alberta, 15 percent for British Columbia and 13 percent for Manitoba. Figures 6.9 and 6.10 show the similar impacts on employment, and federal and provincial taxes.

**Figure 6.8**
**Total GDP Impacts ($million)**

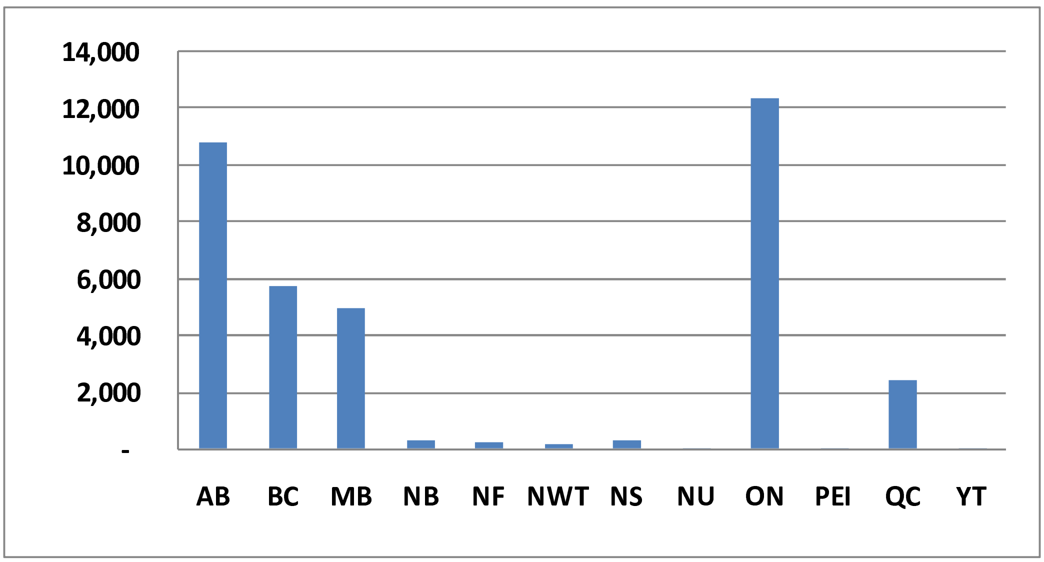


**Figure 6.9**
**Total Employment Impacts (thousand person years)**

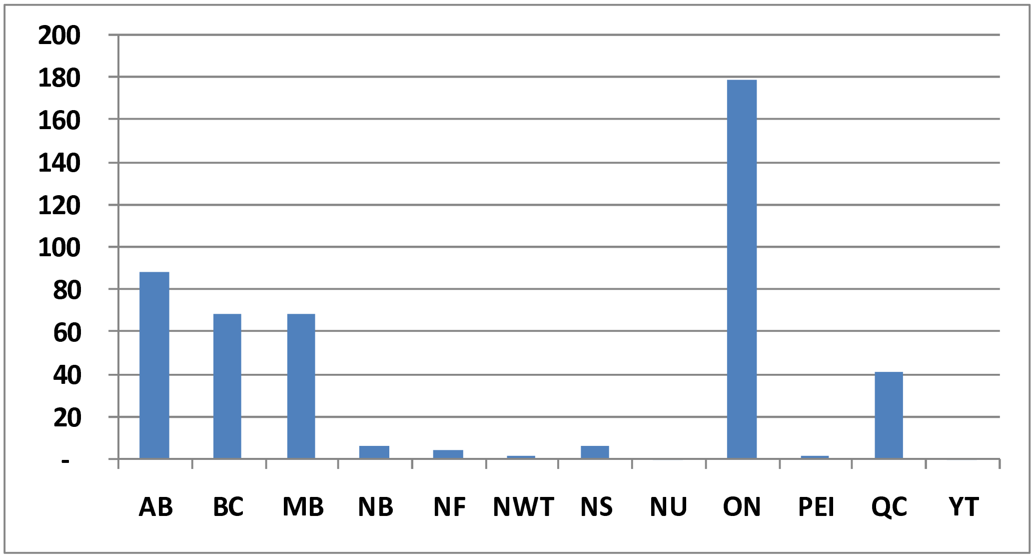
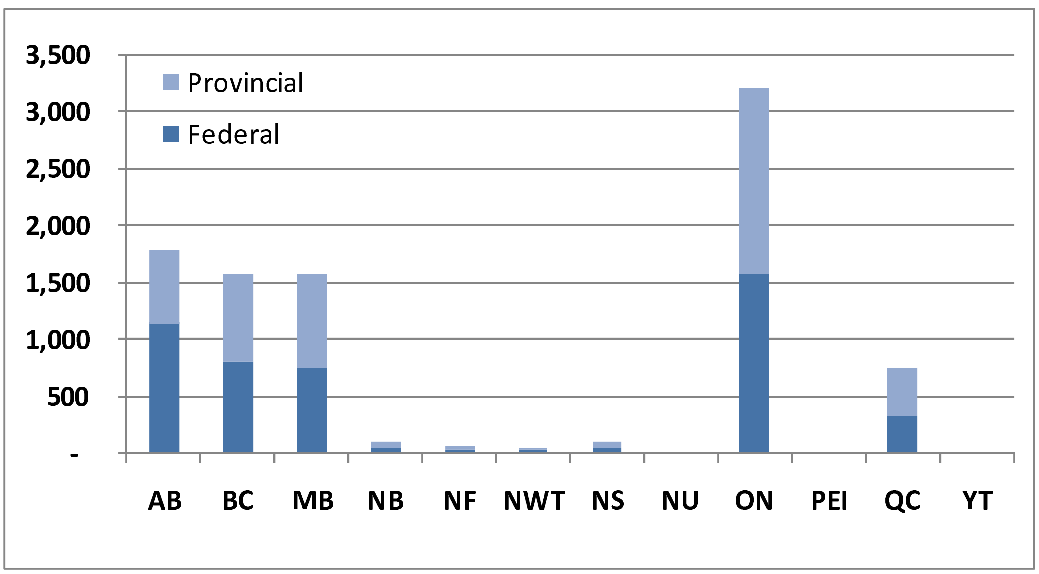



**Figure 6.10**
**Total Federal and Provincial Tax Impacts ($million)**

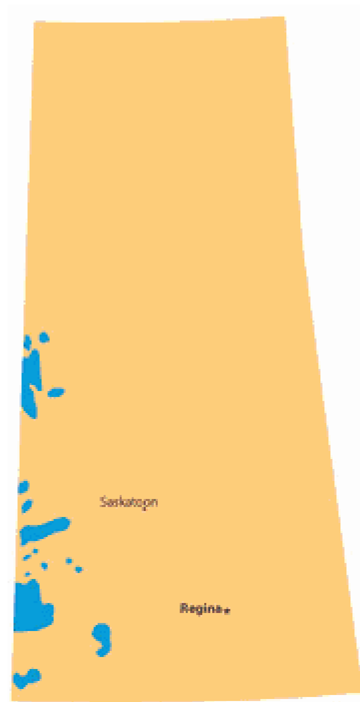



## 6.3 Conventional Gas Resources

### 6.3.1 Background

Natural gas in Saskatchewan tends to be dry and sweet. It is concentrated in the southwest part of the province, where production has occurred since 1934. Figure 6.11 shows conventional natural gas pools in Saskatchewan.[82] In 2007, Saskatchewan produced 313.9 Bcf of natural gas, making it the third largest producer of natural gas in Canada after Alberta and British Columbia. Drilling has been in a continual decline since 2003, and in 2007 there were only 1,156 new wells drilled. This brought the total number of active wells in the province to 19,531.[83] Reserves of natural gas in Saskatchewan at the end of 2006 were estimated at 3.5 Tcf.[84]

**Figure 6.11**
**Natural Gas Reserves in Saskatchewan**




Source: Centre for Energy.

### 6.3.2 Forecasts

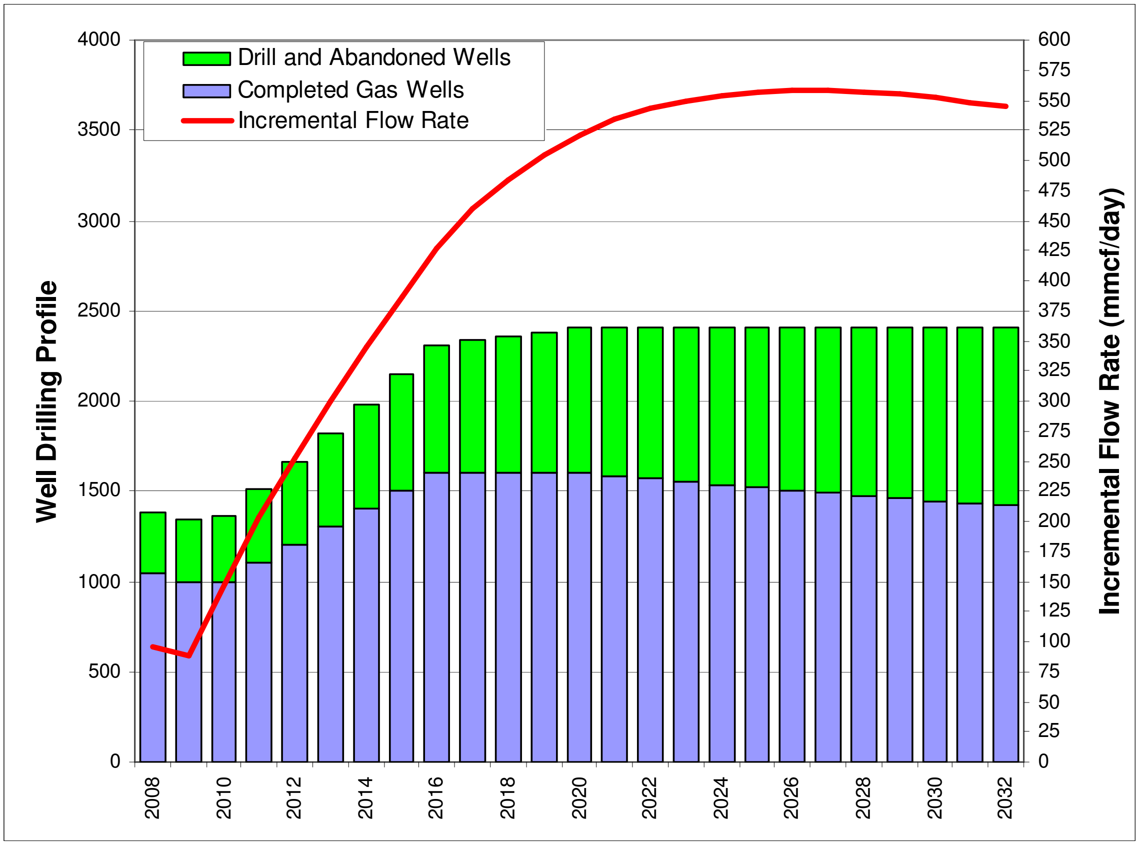
Figure 6.12 represents CERI's view of conventional gas resource developments broken down into forecasted new gas well connections and associated non-productive wells that are a typically part of the exploration and development activities. The latter are labeled dead and abandoned wells. This figure also indicates the resulting incremental gas flow rate from the completed gas wells.

[82]Centre for Energy, *Saskatchewan Energy Facts & Statistics*. http://www.centreforenergy.com/FactsStats/MapsCanada/SK-EnergyMap.asp

[83] Government of Saskatchewan Energy and Resources, Oil and Gas Summaries, *Crude Oil in Saskatchewan.* http://www.ir.gov.sk.ca/adx/aspx/adxGetMedia.aspx?DocID=6552,3384,5460,2936,Documents&MediaID=20542&Filename=Fact+Sheet+-+Oil+in+Sask+(Sept+8+2008).pdf

[84] Canadian Association of Petroleum Producers, Industry Facts and Information, Saskatchewan. *2007 Statistics*. http://membernet.capp.ca/raw.asp?x=1&dt=NTV&e=PDF&dn=34092 and Centre for Energy, *Saskatchewan Energy Facts & Statistics*.

**Figure 6.12**
**Well Drilling Profile and Incremental Flow Rate (25-Year Forecast)**




### 6.3.3 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 6.4 and 6.5, 81 percent of the impacts are directly related to Saskatchewan, with the remaining 19 percent being felt across the other provinces and territories.

In addition to the economic impacts listed in the tables below, the royalties payable to the province of Saskatchewan in regard to Saskatchewan conventional gas, over the next 25-years, will be $3,719 million. On average, this equates to approximately $149 million per year.

**Table 6.4**
**Impacts Associated with Investment in Saskatchewan**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 1,872 | 15 | 310 | 197 | 113 |
| **British Columbia** | 986 | 12 | 270 | 139 | 131 |
| **Manitoba** | 358 | 7 | 114 | 55 | 60 |
| **New Brunswick** | 48 | 1 | 17 | 8 | 8 |
| **Newfoundland & Labrador** | 29 | 1 | 9 | 4 | 5 |
| **Northwest Territories** | 27 | 0 | 7 | 5 | 2 |
| **Nova Scotia** | 72 | 1 | 25 | 12 | 13 |
| **Nunavut** | 4 | 0 | 2 | 2 | 1 |
| **Ontario** | 2,133 | 31 | 552 | 271 | 281 |
| **Prince Edward Island** | 8 | 0 | 3 | 2 | 2 |
| **Quebec** | 408 | 7 | 127 | 55 | 72 |
| **Saskatchewan** | 26,111 | 187 | 6,931 | 3,406 | 3,524 |
| **Yukon Territory** | 4 | 0 | 2 | 1 | 1 |
| **Canada** | 32,061 | 262 | 8,369 | 4,156 | 4,213 |

**Table 6.5**
**Impacts Associated with Operation in Saskatchewan**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 1,624 | 13 | 269 | 171 | 98 |
| **British Columbia** | 855 | 10 | 234 | 120 | 114 |
| **Manitoba** | 311 | 6 | 99 | 47 | 52 |
| **New Brunswick** | 42 | 1 | 15 | 7 | 7 |
| **Newfoundland & Labrador** | 25 | 1 | 8 | 3 | 4 |
| **Northwest Territories** | 23 | 0 | 6 | 4 | 2 |
| **Nova Scotia** | 62 | 1 | 22 | 10 | 12 |
| **Nunavut** | 4 | 0 | 2 | 1 | 0 |
| **Ontario** | 1,851 | 27 | 479 | 235 | 244 |
| **Prince Edward Island** | 7 | 0 | 3 | 1 | 2 |
| **Quebec** | 354 | 6 | 110 | 47 | 62 |
| **Saskatchewan** | 22,653 | 162 | 6,013 | 2,955 | 3,058 |
| **Yukon Territory** | 4 | 0 | 2 | 1 | 1 |
| **Canada** | 27,815 | 227 | 7,261 | 3,606 | 3,655 |

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 6.13, Ontario receives 36 percent of the impacts, 31 percent for Alberta, 17 percent for British Columbia and 7 percent for Quebec. Figures 6.14 and 6.15 show the similar impacts on employment, and federal and provincial taxes.

**Figure 6.13**
**Total GDP Impacts ($million)**

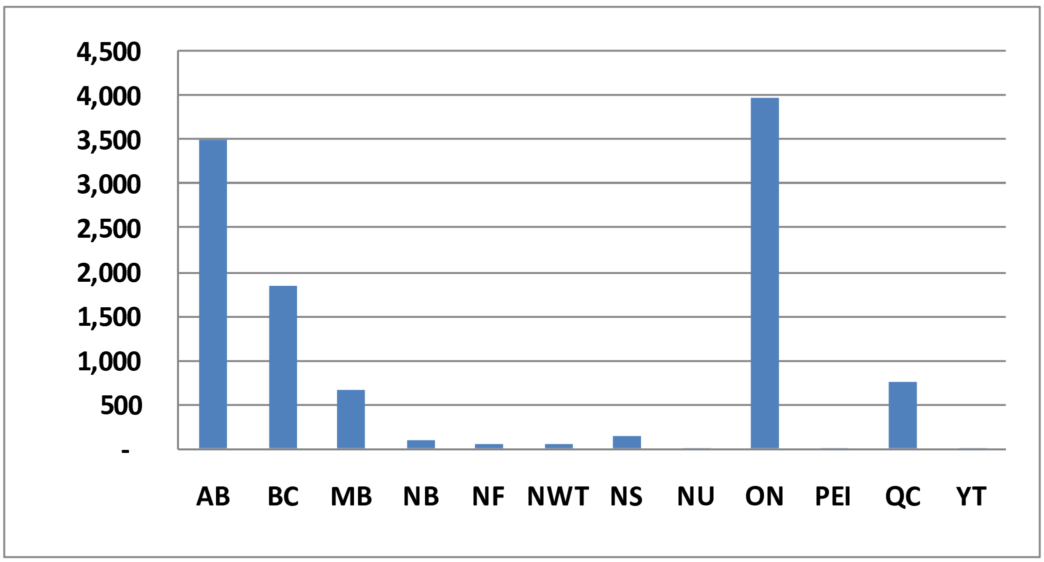



**Figure 6.14**
**Total Employment Impacts (thousand person)**

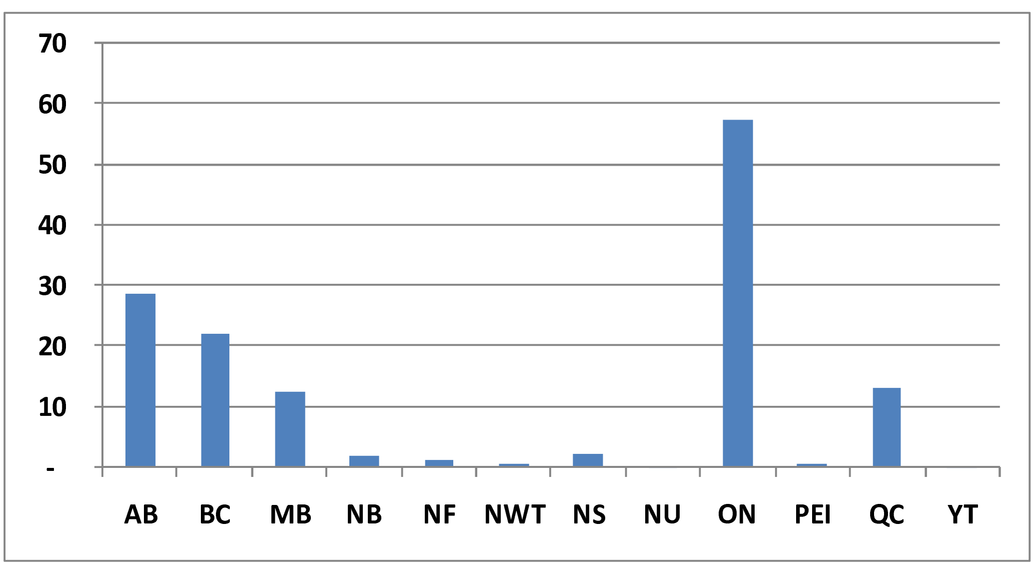
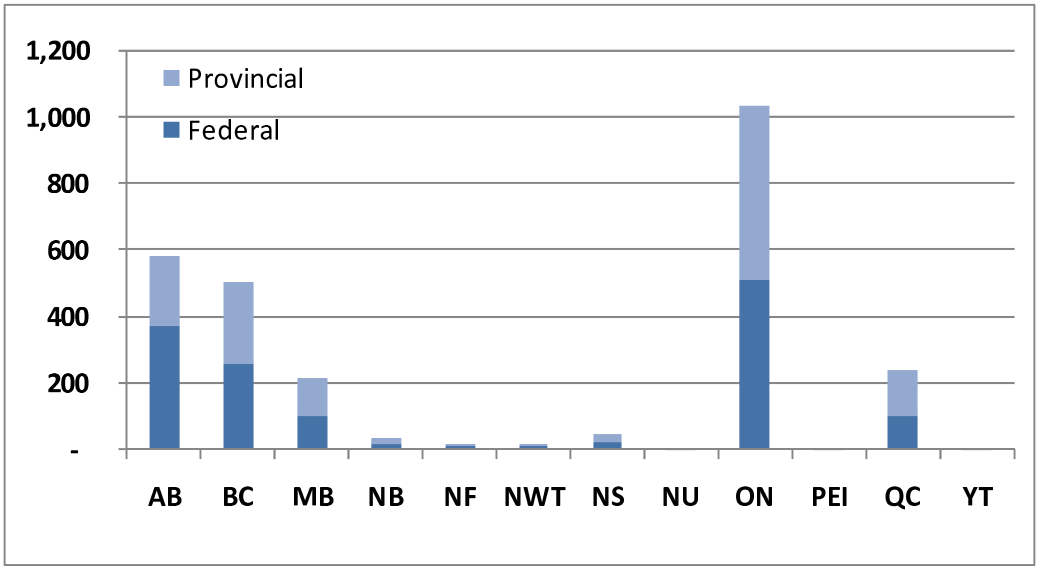


**Figure 6.15**
**Total Federal and Provincial Tax Impacts ($million)**




## 6.4 Bakken Oil Shale Resources

The following section presents an overview of the Bakken oil shale play. The remainder of this section reviews the economic impacts of this particular resource to the province and the rest of Canada's provinces.

### 6.4.1 Background

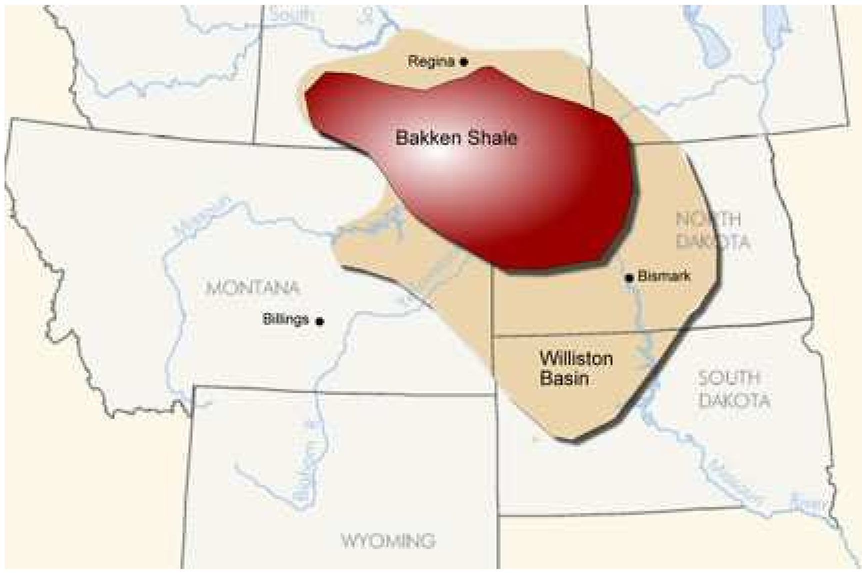
Geologists have known about the Bakken formation since the 1950's. The formation makes up an area of approximately 200,000 square miles of the Williston Basin, the largest sedimentary basin in the continental US. The Bakken Shale stretches across southern Saskatchewan, northeastern Montana, and northwestern North Dakota, and into southeastern parts of Manitoba. Figure 6.16 shows where the late Devonian to early Mississippian Bakken is embedded within the Williston Basin.

Initial reports in 1995, by the United States Geological Survey (USGS), estimated the discovery of 151 million barrels of recoverable oil shale in the region. However, with new innovations in geological exploration and advances in drilling technology, the number was increased to 3.65 billion barrels of recoverable oil in 2008.[85] The USGS calls it the largest unconventional oil accumulation it has ever assessed. The area also is estimated to contain 1,848 Bcf of gas and 148 million barrels of NGLs. Currently, Elm Coulee (Montana), Parshall field (North Dakota), Nesson Anticline (North Dakota) and Viewfield (Saskatchewan) are the areas that have witnessed

[85] USGS News Release April 10th, 2008: http://www.usgs.gov/newsroom/article.asp?ID=1911

major development in the Bakken.[86] The majority of activity remains on the US-side of the Bakken.

**Figure 6.16**
**The Bakken Formation**




Source: http://www.sheridancountyonline.com/bakken_formation.html

A batch of major drilling activities occurred in 1988 near the North Dakota-Montana border. Early horizontal drilling methods were used to extract the upper part of the Bakken shale. In 2000, the Elm Coulee Field was discovered in Richland County, Montana. The discovery of the field led to extensive expansions in the development and drilling for Bakken shale. Since its discovery, more than 75 million barrels of oil have been produced from the field, making it one of the highest producing onshore fields in the United States.[87]

The high price of oil, along with the success of the Elm Coulee Field discovery, encouraged oil companies to further explore and drill other portions of the Williston Basin. In 2006, EOG Resources Inc. discovered the Parshall Field in Mountrail County, North Dakota. It is estimated to contain 80 million barrels of oil[88], and by the end of 2008, EOG was producing approximately 24 Mcf/d of crude oil from the Bakken play in North Dakota. The Texas-based company, one of the largest independent oil and natural gas companies in the United States, has plans to expand drilling by around 45 new wells in 2009.[89] In addition, the Nesson Anticline Field is attracting attention. It is positioned in the midst of the Three Forks, an oil area below the upper part of the

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[86] Hart Energy Publishing, LP "Bakken Shale Play Book" A supplement to *Oil and Gas Investor*, *E&P and Pipeline and Gas Technology*. Issued December 2008. Page 23

[87] EIA Report: http://archive.bigskybusiness.com/index.php?name=News&file=article&sid=1504

[88] Bank of America Energy Conference, November 15, 2007 http://www.eogresources.com/investors/investor_pres.html

[89] 2008 Annual Report, EOG Resources Inc.: http://www.eogresources.com/investors/reports/2008/EOGR_2008_Annual_Report.pdf

Bakken oil shale formation located in various North Dakota counties.[90] Petro-Hunt currently has control over the "sweet spots" of the Three Forks unit producing 1,500 barrels of oil a day.[91]

Oil production on the Canadian-side of the border, Saskatchewan in specific, averaged 56,000 b/d by the end of 2007.[92] Operations in Saskatchewan started in the mid-1950s producing low volumes at Rancott Field and Rocanville. At present, the most active Bakken Shale development is in the area of Viewfield, close to the US border. Drilling is focused in the lower part of the Middle Bakken where coarse siltstone is widespread. The siltstone has a thickness ranging from 30 to 60 feet and 12 percent porosity, with permeability between 0.4 to 0.6 millidarcy (md).

Crescent Point Energy Trust is the main player on the Canadian-side of the Bakken, holding 288,000 net acres and producing around 16,000 barrels of oil equivalent per day. Crescent Point suggests that the southeastern portion of the Bakken play may contain 5 billion barrels of oil equivalent of in-place resources, making it one of the largest oil finds in the past half century in Western Canada. [93]

Other Canadian players include Crow Crown Point Ventures Ltd, Painted Pony Petroleum Ltd, Petrobank Energy and Resources Ltd, Reece Energy Exploration Corp., Ryland Oil Corp., Shelter Bay Energy Ltd, Talisman Energy Inc and TriStar Oil & Gas Ltd.

### 6.4.2 Economic Impacts

Economic impacts for the Bakken and other conventional oil resources are contained in Section 6.2.

## 6.5 Oil Sands Resources

### 6.5.1 Background

While far less known than its Albertan counterpart, oil sands in Saskatchewan are attracting a great deal of attention. The oil sands in Saskatchewan are found in the lower cretaceous Dina Formation, which extends from Alberta's McMurray Formation. The first interest in Saskatchewan's oil sands took place from 1974 to 1976 in Clearwater River Valley, located in the northwestern part of the province. During that period, drilling activity started by Shell Canada and Gulf Canada in which they identified the bitumen deposits. Exploitation of the resource, however, was ruled uneconomic due to technological limitations.

Nearly thirty years later, in June 2004, the interest for the oil sand deposits in the region was renewed, when Powermax Energy Inc. of Calgary acquired approximately 570,000 hectares,

[90] Three Forks – Sanish: http://bakkenshale.net/threeforkssanish.html

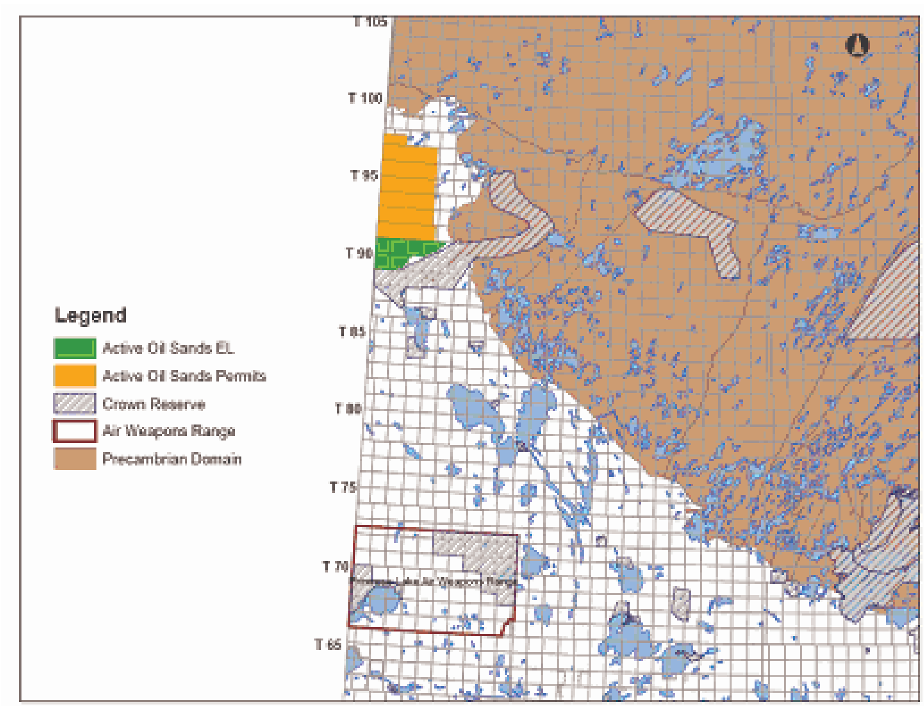
[91] http://oilshalegas.com/bakkenshale.html

[92] Hart Energy Publishing, LP "Bakken Shale Play Book" A supplement to *Oil and Gas Investor*, *E&P and Pipeline and Gas Technology*. Issued December 2008. Page 32

[93] Ibid, page 19.

north of the Clearwater River.[94] The area of interest, located along the Alberta-Saskatchewan border, just north of the Cold Lake Weapons Range, is illustrated in Figure 6.17. Oilsands Quest Inc later acquired these land permits, in which they relinquished 228,000 hectares and soon after started drilling exploration wells in the remaining 342,000 hectares of the region.

**Figure 6.17**
**Saskatchewan's Active Oil Sands Dispositions**




Source:
http://www.ir.gov.sk.ca/adx/aspx/adxGetMedia.aspx?DocID=5404,3383,3384,5460,2936,Documents&MediaID=19413&Filename=Oil+Sands+Permits.pdf

By November 2007, 221 wells have been drilled and an initial report of about 1.5 billion barrels of bitumen was noted and on June 2008, Oilsands Quest nudged that number up to 6.6 billion barrels. The area of the original discovery by Oilsands Quest is now called the Axe Lake Discovery in which three reservoir test sites began construction in March of 2008 and plans for placing horizontal wells should commence in 2009.

Other players include Indian Oilsands Corporation, who signed a Memorandum of Understanding (MOU) with the Chinese Petroleum Corporation (CPC) to explore and develop the area. Saskatchewan First Nations are in the process of securing land in northwestern Saskatchewan under the Treaty Land Entitlement clause. When that is complete, CPC has agreed to invest an initial $800 million and more investment would follow if the Taiwan based company observe any potential.

[94] "Oil Sands in Saskatchewan", Saskatchewan Industry and Resources, 2005.

### 6.5.2 Economic Impacts

While the Saskatchewan oil sands are attracting attention, the full extent of the resource, as described above, is in the process of being defined. In addition, the limited amount of drilling and current economic climate, make calculating economic impacts unfeasible. This is illustrated by Tables 6.6 and 6.7.

**Table 6.6**
**Impacts Associated with Investment in Saskatchewan**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | - | - | - | - | - |
| **British Columbia** | - | - | - | - | - |
| **Manitoba** | - | - | - | - | - |
| **New Brunswick** | - | - | - | - | - |
| **Newfoundland & Labrador** | - | - | - | - | - |
| **Northwest Territories** | - | | | | - |
| **Nova Scotia** | - | | | | - |
| **Nunavut** | - | | | | - |
| **Ontario** | - | - | - | - | - |
| **Prince Edward Island** | - | - | - | - | - |
| **Quebec** | - | - | - | - | - |
| **Saskatchewan** | - | - | - | - | - |
| **Yukon Territory** | - | - | - | - | - |
| **Canada** | - | - | - | - | - |

**Insufficient data to perform analysis**

**Table 6.7**
**Impacts Associated with Operation in Saskatchewan**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | - | - | - | - | - |
| **British Columbia** | - | - | - | - | - |
| **Manitoba** | - | - | - | - | - |
| **New Brunswick** | - | - | - | - | - |
| **Newfoundland & Labrador** | - | - | - | - | - |
| **Northwest Territories** | - | | | | - |
| **Nova Scotia** | - | | | | - |
| **Nunavut** | - | | | | - |
| **Ontario** | - | - | - | - | - |
| **Prince Edward Island** | - | - | - | - | - |
| **Quebec** | - | - | - | - | - |
| **Saskatchewan** | - | - | - | - | - |
| **Yukon Territory** | - | - | - | - | - |
| **Canada** | - | - | - | - | - |

**Insufficient data to perform analysis**

## 6.6 Major Capital Projects

### 6.6.1 Background

The following table presents a summary of mid-stream oil and gas projects announced in the province, as of Q1 2009. The table includes a brief description of the projects, its cost and approximate timeline.

**Table 6.8**
**Summary of Saskatchewan Major Oil and Gas Project Inventory**

| Project Name/Organization | Description | Cost ($million) | Time Duration |
|---|---|---|---|
| Lloydminster Upgrader Expansion Husky Energy Inc. | Project proceeding | | |
| Carbon Dioxide Enhanced Oil Recovery | Encana Corporation Weyburn $CO_2$ | 1,100 | |
| TransGas (SaskEnergy) | Timber Cove to La Ronge Pipeline | 21 | 2008-2009 |
| Apache Canada Midale CO2 | Carbon Dioxide Enhanced Oil Recovery | 95 | |
| Husky energy | Lloydminster Upgrader maintenance | 75 | 2008 |
| Enbridge pipelines (Saskatchewan) Inc. | Westspur Pipeline Expansion (crude oil) | 21.7 (Sask. portion) | 2008 |
| Transcanada Keystone Pipeline GP Ltd. | Keystone Oil pipeline | 664 | 2008-2009 |

Source: 2008 Major Projects Inventory, Saskatchewan Ministry of Enterprise and Innovation.

### 6.6.2 Economic Impacts

As previously mentioned, this study attempted to analyze the economic impacts of the Co-op Refinery Expansion in Regina, but due to insufficient data no results were achieved, as indicated by Tables 6.9 and 6.10.

**Table 6.9**
**Impacts Associated with Investment in Saskatchewan**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | - | - | - | - | - |
| **British Columbia** | - | - | - | - | - |
| **Manitoba** | - | - | - | - | - |
| **New Brunswick** | - | - | - | - | - |
| **Newfoundland & Labrador** | - | - | - | - | - |
| **Northwest Territories** | - | - | - | - | - |
| **Nova Scotia** | - | - | - | - | - |
| **Nunavut** | - | - | - | - | - |
| **Ontario** | - | - | - | - | - |
| **Prince Edward Island** | - | - | - | - | - |
| **Quebec** | - | - | - | - | - |
| **Saskatchewan** | - | - | - | - | - |
| **Yukon Territory** | - | - | - | - | - |
| **Canada** | - | - | - | - | - |

**Insufficient data to perform analysis**

**Table 6.10**
**Impacts Associated with Operation in Saskatchewan**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| Alberta | - | - | - | - | - |
| British Columbia | - | - | - | - | - |
| Manitoba | - | - | - | - | - |
| New Brunswick | - | - | - | - | - |
| Newfoundland & Labrador | - | - | - | - | - |
| Northwest Territories | - | | | | - |
| Nova Scotia | - | | | | - |
| Nunavut | - | | | | - |
| Ontario | - | - | - | - | - |
| Prince Edward Island | - | - | - | - | - |
| Quebec | - | - | - | - | - |
| Saskatchewan | - | - | - | - | - |
| Yukon Territory | - | - | - | - | - |
| Canada | - | - | - | - | - |

**Insufficient data to perform analysis**

# CHAPTER 7
# ECONOMIC IMPACTS: MANITOBA

This chapter discusses the economic impacts for the province of Manitoba. It is divided into two sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Manitoba. The second section discusses and reviews the economic impacts of conventional oil resources in the province. This section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 7.1 Background

This section describes the reserves, production, and expenditures of crude oil industry in the province of Manitoba. In this section, the methodology that has been used for regrouping components of oil expenditures is demonstrated.

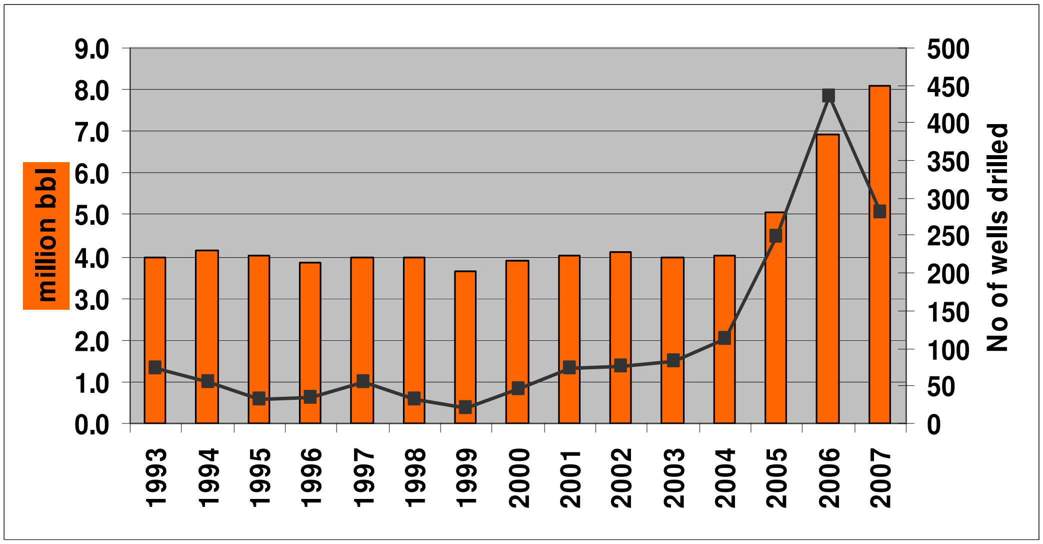
### 7.1.1 Crude Oil Reserves and Production

According to CAPP, the remaining established reserves of crude oil in Manitoba as of December 2006 were 44.5 million bbl. This was a net increase of almost 19 million bbl in comparison to the 2005 reserves. The increase is the result of all reserves additions less 2006 production.

Crude oil production in Manitoba has been increasing after remaining level between 1993 and 2004. Between 2005 and 2007, production increased at an average annual rate of 5.1 percent. In 2007, Manitoba produced slightly more than 8 million barrels of crude oil. Crude oil production and number of wells drilled are illustrated in Figure 7.1. The number of oil wells drilled and completed also increased from 74 wells in 1993 to 280 wells in 2007.

The Manitoba's crude oil reserves production ratio is approximately 6 years.

**Figure 7.1**
**Manitoba Crude Oil Production and Number of Wells Drilled**
**1993 – 2007**




Source: CAPP, Statistical Handbook, September 2008.

### 7.1.2 Expenditures of the Petroleum Industry in Manitoba

The Canadian Association of Petroleum Producers[95] reports the net cash expenditures[96] of Manitoba's crude oil industry for exploration, development, operating and royalties as follows.

A- Exploration
- A1- Geological & Geophysical
- A2- Drilling
- A3- Land

B- Development
- B1- Drilling
- B2- Field Equipment
- B3- EOR
- B4- Gas Plant

C- Operating
- C1- Wells & Flow lines
- C2- Gas Plants

D- Royalties

The CAPP reports that in 2007, $369 million were spent by the oil industry in Manitoba. The largest investment expenditures were for development, approximately 54 percent. Royalties, operating and exploration follow at 23 percent, 14 percent and 9 percent, respectively.

[95] CAPP - TECHNICAL REPORT, Statistical Handbook, For Canada's Upstream Petroleum Industry, September 2008, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=132330
[96] Net cash expenditure exclude inter-industry transactions

Table 7.1 summarizes the methodology that has been used for regrouping the above components of petroleum expenditures to the following categories: drilling investment expenditure, field equipment investment expenditure, operating expenditure and royalties and fees expenditure.

**Table 7.1**
**Disaggregating Oil Expenditures**

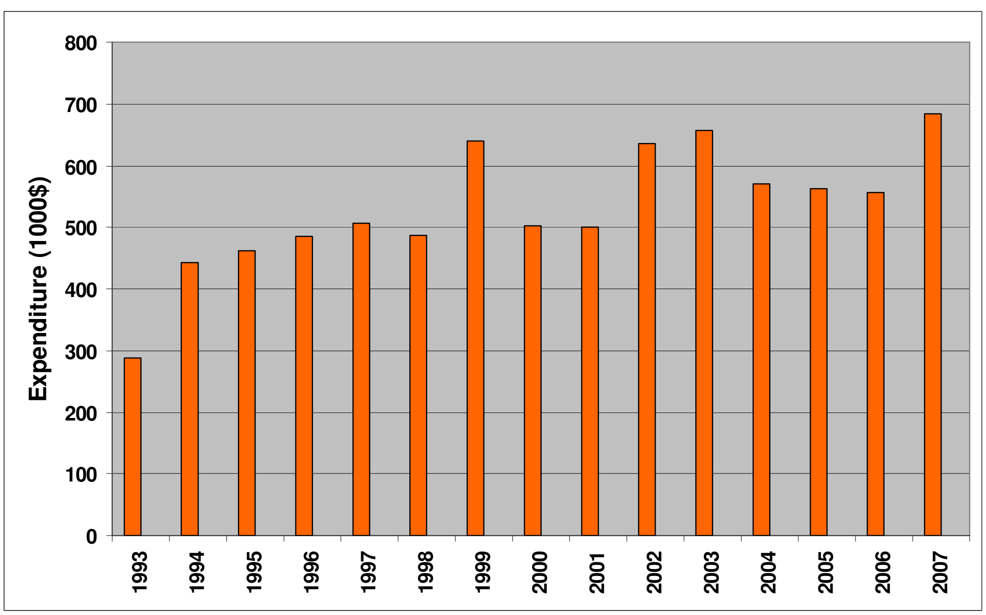
| |
|---|
| Drilling Investment Expenditure:<br>A1 + A2 + B1 |
| Field Equipment Expenditure:<br>B2 + B3 |
| Operating Expenditure:<br>C1 |

Drilling Investment Expenditure

In 2007, Manitoba drilled 280 oil wells, with a total depth drilled of 318,406 meters. Between 1955 and 2007, CAPP reports a total of 4,053 oil wells drilled.

Figure 7.2 shows that the drilling investment per well in Manitoba increased from $288,000 in 1993 to $684,000 in 2007.

**Figure 7.2**
**Manitoba Oil Drilling Investment per Well Drilled**
**1993 - 2007**

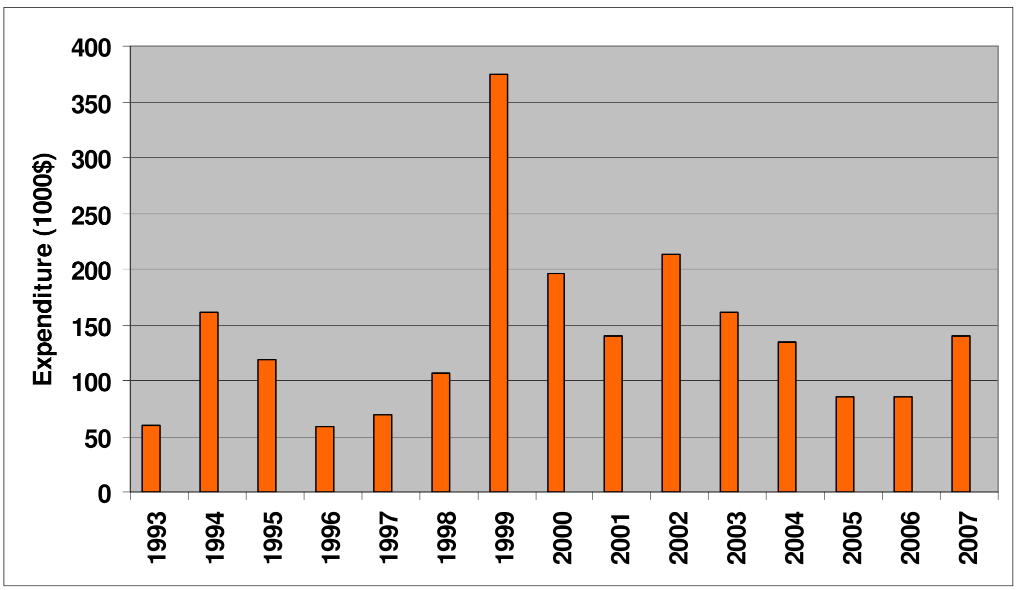


Field Investment Expenditure

The major part of field equipment investment includes expenditures of field facilities, crude oil battery, and gathering systems.

Figure 7.3 shows oil field investment per well drilled between 1993 and 2007. Over that time period, Manitoba's field investment per oil well peaked dramatically at $375,000 in 1999, and thereafter declined to $85,000 in 2005. In 2007, field investment per oil well was $140,000.

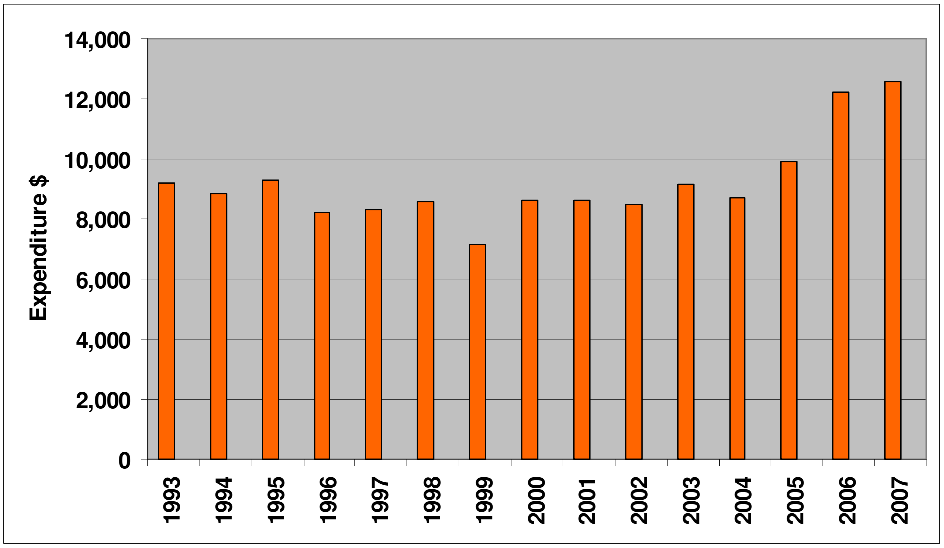
**Figure 7.3**
**Manitoba Oil Field Investment per Well Drilled**
**1993-2007**




Operating Expenditure

For estimation of per well operating expenditures, CERI divides oil operation expenditures (C1) by the total cumulative oil wells drilled. Figure 7.4 shows that from 1993 to 2005, operating expenditures per oil well range between $8,100 and $12,000. In 2007, operating expenditure per oil well exceeded $12,000.

**Figure 7.4**
**Manitoba Oil Operating Expenditures per Cumulative Successful Well**
**1993-2007**



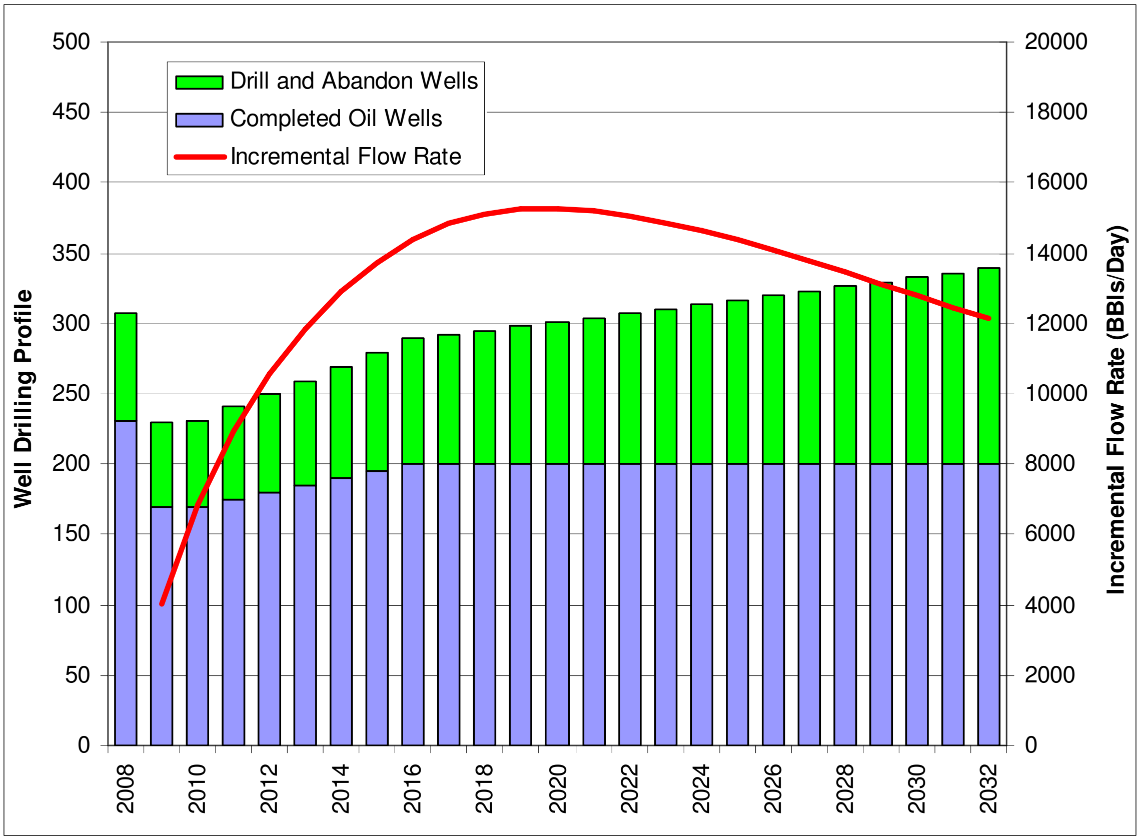

Source: CAPP, Statistical Handbook, September 2008.

## 7.2 Conventional Oil Resources

### 7.2.1 Forecasts

Figure 7.5 represents CERI's view of conventional oil resource developments broken down into forecasted new oil well connections and associated non-productive wells that are a typically part of the exploration and development activities. The latter are labeled dead and abandoned wells. This figure also indicates the resulting incremental oil flow rate from the completed oil wells.

**Figure 7.5**
**Well Drilling Profile and Incremental Flow Rate (25-Year Forecast)**




### 7.2.2 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 7.2 and 7.3, 85 percent of the impacts are directly related to Manitoba, with the remaining 15 percent being felt across the other provinces and territories.

In addition to the economic impacts listed in the tables below, the royalties payable to the province of Manitoba in regard to Manitoba conventional oil, over the next 25-years, will be $543 million. On average, this equates to approximately $22 million per year.

**Table 7.2**
**Impacts Associated with Investment in Manitoba**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 159 | 2 | 26 | 17 | 10 |
| **British Columbia** | 124 | 2 | 34 | 18 | 17 |
| **Manitoba** | 4,656 | 49 | 1,485 | 709 | 776 |
| **New Brunswick** | 12 | 0 | 4 | 2 | 2 |
| **Newfoundland & Labrador** | 9 | 0 | 3 | 1 | 2 |
| **Northwest Territories** | 3 | 0 | 1 | 0 | 0 |
| **Nova Scotia** | 13 | 0 | 5 | 2 | 2 |
| **Nunavut** | 1 | 0 | 0 | 0 | 0 |
| **Ontario** | 281 | 4 | 73 | 36 | 37 |
| **Prince Edward Island** | 2 | 0 | 1 | 0 | 0 |
| **Quebec** | 127 | 2 | 39 | 17 | 22 |
| **Saskatchewan** | 79 | 1 | 21 | 10 | 11 |
| **Yukon Territory** | 1 | 0 | 0 | 0 | 0 |
| **Canada** | 5,467 | 61 | 1,693 | 813 | 880 |

**Table 7.3**
**Impacts Associated with Operation in Manitoba**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 187 | 2 | 31 | 20 | 11 |
| **British Columbia** | 147 | 2 | 40 | 21 | 20 |
| **Manitoba** | 5,496 | 58 | 1,753 | 837 | 916 |
| **New Brunswick** | 14 | 0 | 5 | 2 | 3 |
| **Newfoundland & Labrador** | 10 | 0 | 3 | 1 | 2 |
| **Northwest Territories** | 3 | 0 | 1 | 1 | 0 |
| **Nova Scotia** | 16 | 0 | 5 | 3 | 3 |
| **Nunavut** | 1 | 0 | 1 | 0 | 0 |
| **Ontario** | 331 | 5 | 86 | 42 | 44 |
| **Prince Edward Island** | 3 | 0 | 1 | 1 | 1 |
| **Quebec** | 150 | 2 | 46 | 20 | 26 |
| **Saskatchewan** | 94 | 1 | 25 | 12 | 13 |
| **Yukon Territory** | 1 | 0 | 0 | 0 | 0 |
| **Canada** | 6,453 | 72 | 1,998 | 960 | 1,038 |

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 7.6, Ontario receives 35 percent of the impacts, 20 percent for Alberta, 16 percent for Quebec and 15 percent for British Columbia. Figures 7.7 and 7.8 show the similar impacts on employment, and federal and provincial taxes.

**Figure 7.6**
**Total GDP Impacts ($million)**

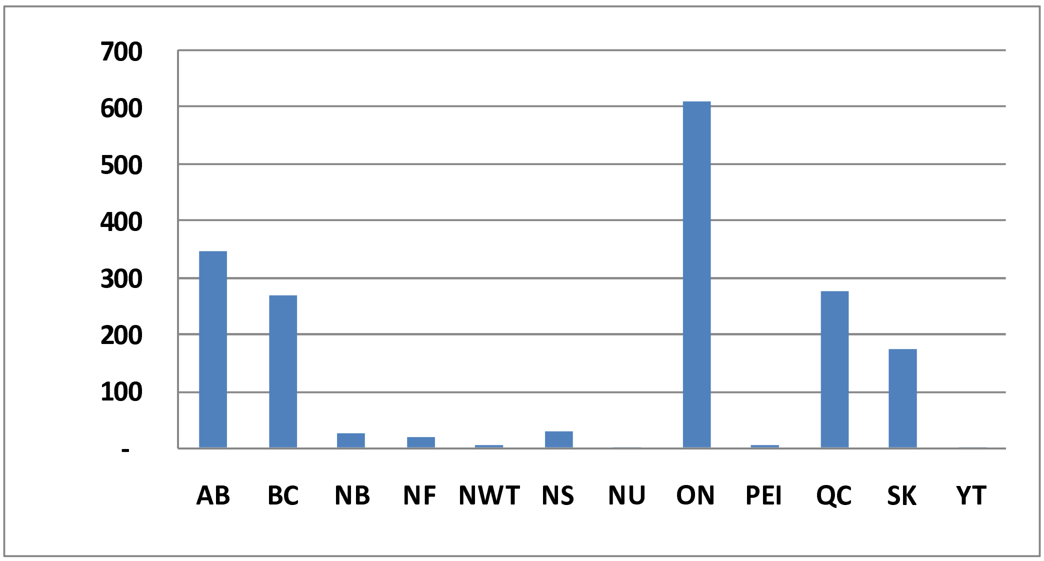



**Figure 7.7**
**Total Employment Impacts (thousand person years)**

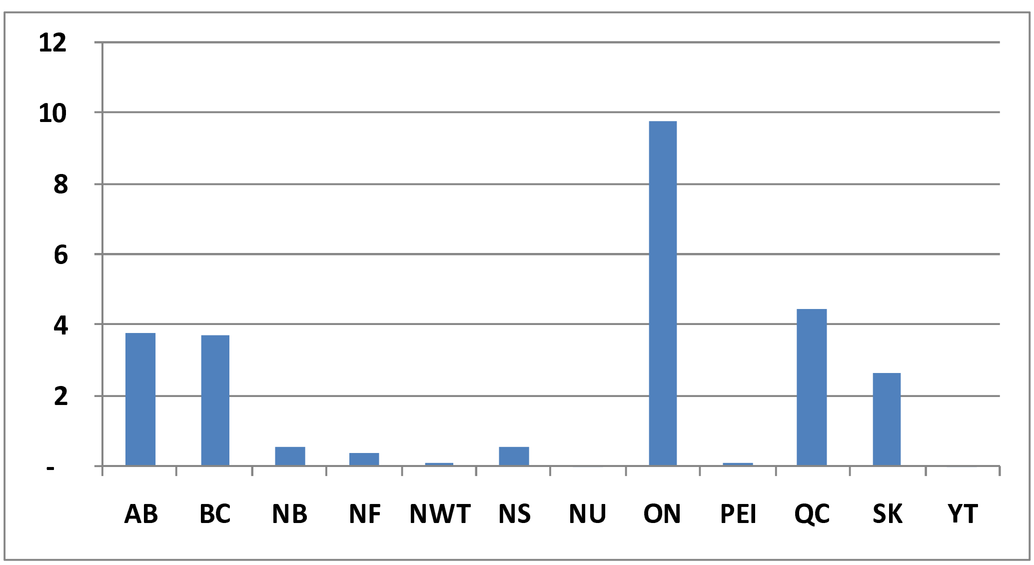
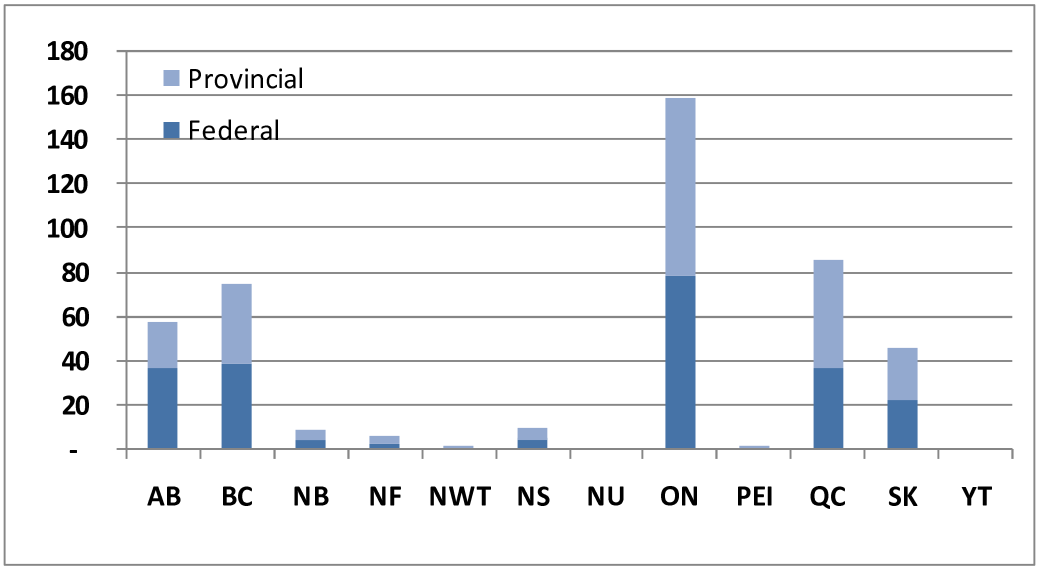


**Figure 7.8**
**Total Federal and Provincial Tax Impacts ($million)**



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# CHAPTER 8
# ECONOMIC IMPACTS: ONTARIO

This chapter discusses the economic impacts for the province of Ontario. It is divided into three sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Ontario. The following two sections discuss and review the economic impacts of conventional oil resources and major capital projects in the province. Each section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 8.1 Background

This section describes the reserves, production, and expenditures of the petroleum industry in the province of Ontario. In this section, the methodology that has been used for regrouping components of petroleum industry's expenditures, and their disaggregation into oil and natural gas is demonstrated.

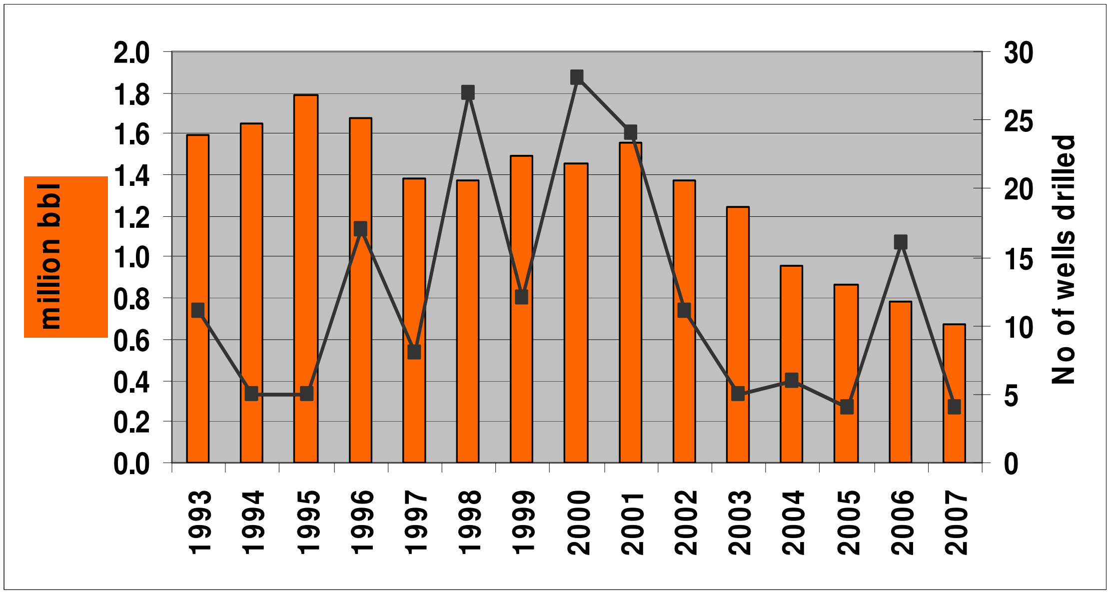
### 8.1.1 Reserves and Production

According to CAPP, the remaining established reserves of crude oil in Ontario, as of December 2006, was 10.5 million barrels. This is a net increase of nearly 4.5 percent from 2005.

Since 2001, Ontario crude oil production has had yearly decline to less than one million barrels per year. Ontario's crude oil production from 1993 to 2007, declined on average annual rate of 5.9 percent, as illustrated in Figure 8.1. Since 2003, the number of oil wells drilled per year has been less than 10. The exception was in 2006, when the number of wells increased to 16.

In 2007, the crude oil reserves production ratio was about 15 years.

**Figure 8.1**
**Ontario Crude Oil Production and Number of Wells Drilled**
**1993 - 2007**



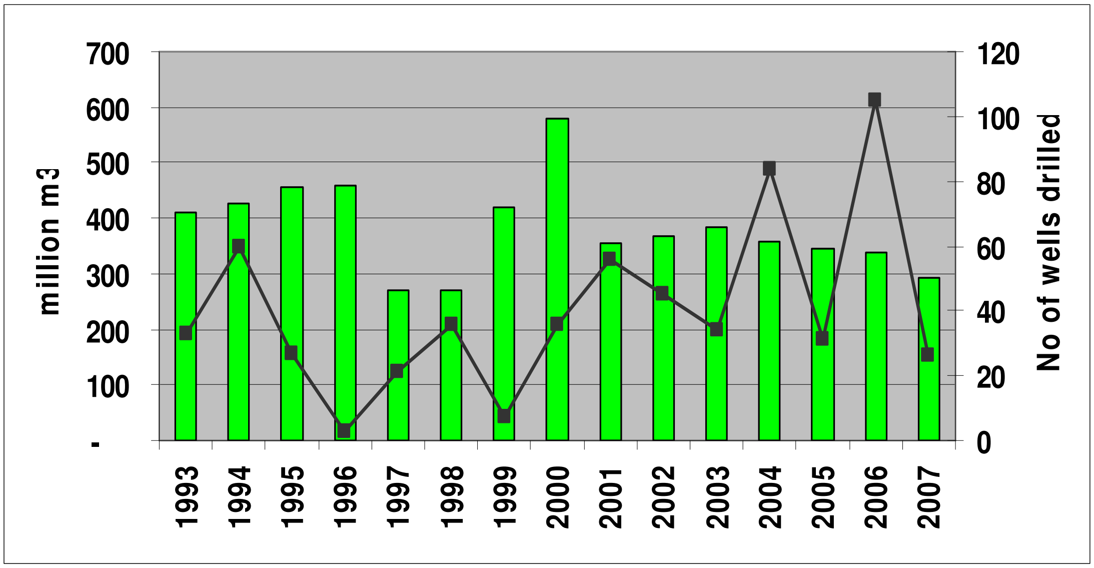

Source: CAPP, Statistical Handbook, September 2008.

According to CAPP, as of December 2006, the remaining established reserves of marketable natural gas were 20 Bcf, an increase of almost 7 billion $m^3$ from the previous year.

Figure 8.2 illustrates marketable natural gas production and the number of wells drilled between 1993 and 2007. Marketable natural gas production in Ontario decreased from 411 million $m^3$ in 1993 to 292 million $m^3$ in 2007, an average annual decline of 2.4 percent. Over the same time period, the number of gas wells drilled decreased from 33 wells in 1993 to 26 wells in 2007.

The natural gas reserves production ratio is about 53 years.

**Figure 8.2**
**Ontario Marketable Natural Gas Production and Number of Wells Drilled**
**1993 - 2007**




Source: CAPP, Statistical Handbook, September 2008.

### 8.1.2 Expenditures of the Petroleum Industry in Ontario

The CAPP[97] reports the net cash expenditures[98] of Ontario's petroleum industry for exploration, development, operating and royalties as follows.

A- Exploration
- A1- Geological & Geophysical
- A2- Drilling
- A3- Land

B- Development
- B1- Drilling
- B2- Field Equipment
- B3- EOR
- B4- Gas Plant

C- Operating
- C1- Wells & Flow lines
- C2- Gas Plants

D- Royalties

The CAPP also reports that in 2007, $79 million was spent by the petroleum industry in Ontario. The largest expenditures were for operating, approximately 50 percent. Royalties, exploration and development follow at 19 percent, 18 percent and 13 percent, respectively.

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[97] CAPP - TECHNICAL REPORT, Statistical Handbook, For Canada's Upstream Petroleum Industry, September 2008, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=132330
[98] Net cash expenditure exclude inter-industry transactions

Table 8.1 summarizes the methodology that has been used for regrouping the components of the petroleum expenditures to the following categories: drilling investment expenditure, field equipment investment expenditure, operating expenditure and royalties and fees expenditure.

**Table 8.1**
**Disaggregation of Oil and Gas Expenditures**

| **Crude Oil** | **Natural Gas** |
|---|---|
| Drilling Expenditure:<br>A1 + A2 + B1 | Drilling Expenditure:<br>A1 + A2 + B1 |
| Field Equipment Expenditure:<br>B2 + B3 | Field Equipment Expenditure:<br>B2 + B4 |
| Operating Expenditure:<br>C1 | Operating Expenditure:<br>C1 + C2 |

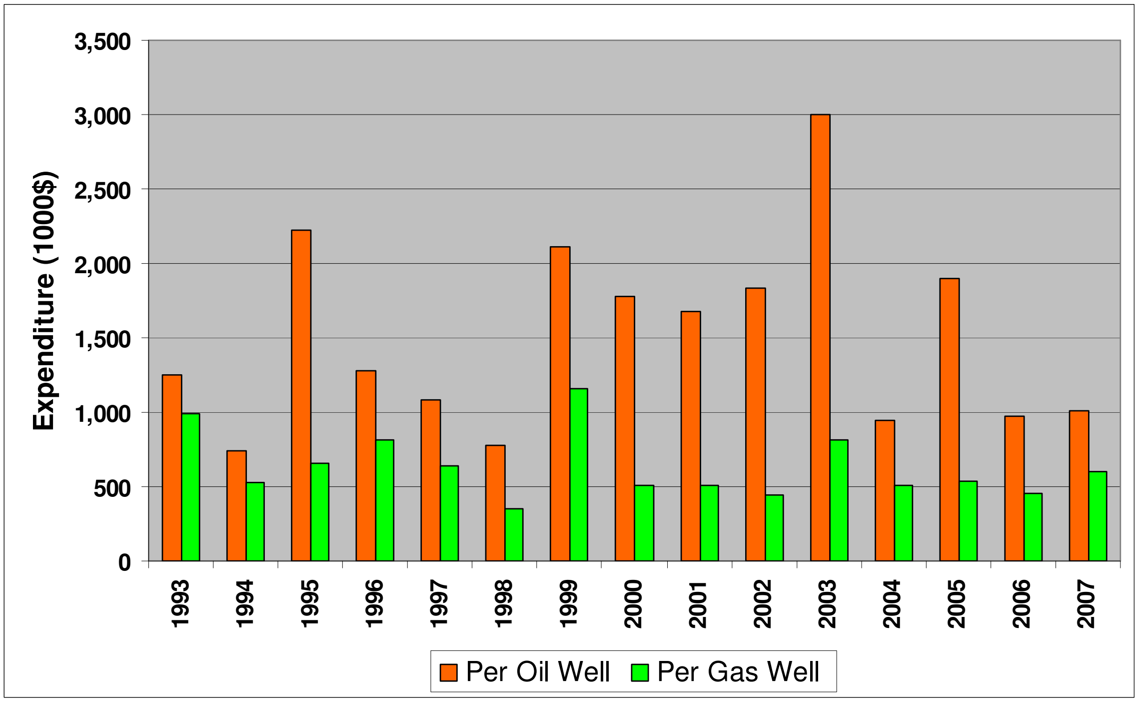
Drilling Investment Expenditure

In 2007, Ontario drilled 30 oil and gas wells, of which more than 86 percent were natural gas. In the same year, the total depth of drilled wells was 10,670 meters. The share of natural gas wells was approximately 80 percent.

Between 1955 and 2007, CAPP reports a total of 601 oil wells and 2,177 gas wells drilled in Ontario. Drilling expenditures of the petroleum industry are taken from CAPP's Statistical Handbook, released in September 2008. These expenditures are disaggregated into oil and gas in proportion to the meters oil and gas wells drilled.

Figure 8.3 shows that Ontario drilling investment per well was greater for oil than for natural gas, at approximately $1 million per oil well and $600,000 per gas well.

**Figure 8.3**
**Ontario Oil and Gas Drilling Investment per Well Drilled**
**1993 - 2007**



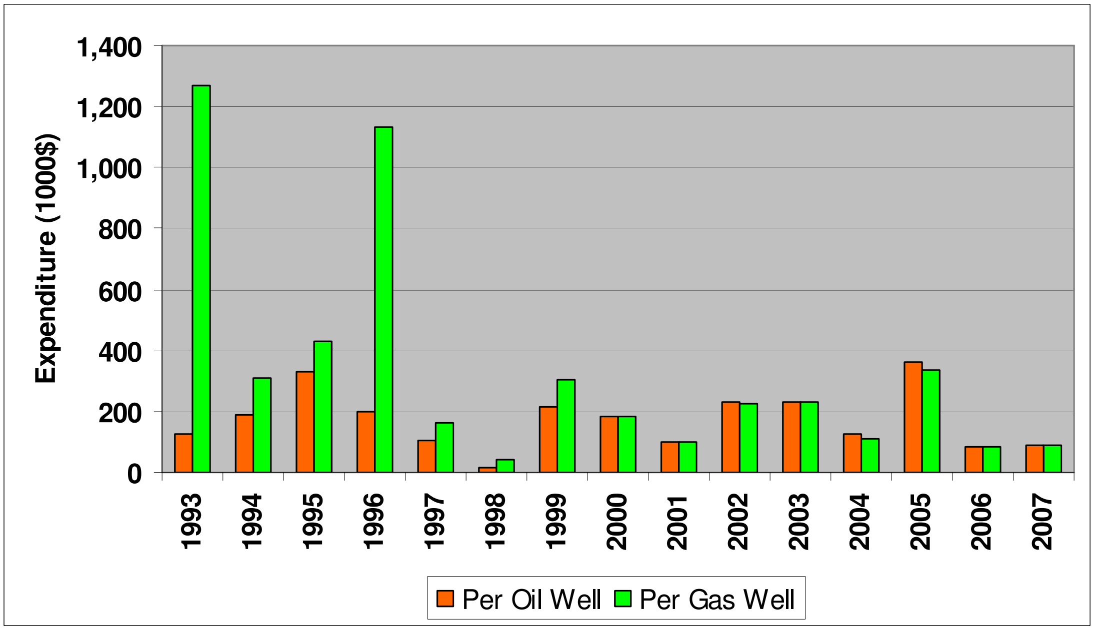

Source: CAPP, Statistical Handbook, September 2008.

Field Investment Expenditure

The major part of field equipment expenditures results from field facilities, crude oil battery and gathering systems. CAPP reports combined oil and gas field equipment expenditure (B2). CERI has disaggregated the above expenditures into oil and gas in proportion to the number of wells drilled. EOR expenditure (B3) was added to oil field investment; similarly, gas plant expenditure (B4) was added to the gas field investment.

It should be noted that from 2000 to 2007 field investment per oil and gas well were almost identical. In 2007, field investment per oil well and gas well was approximately $87,000, as shown in Figure 8.4.

**Figure 8.4**
**Ontario Oil and Gas Field Investment per Well Drilled**
**1993-2007**

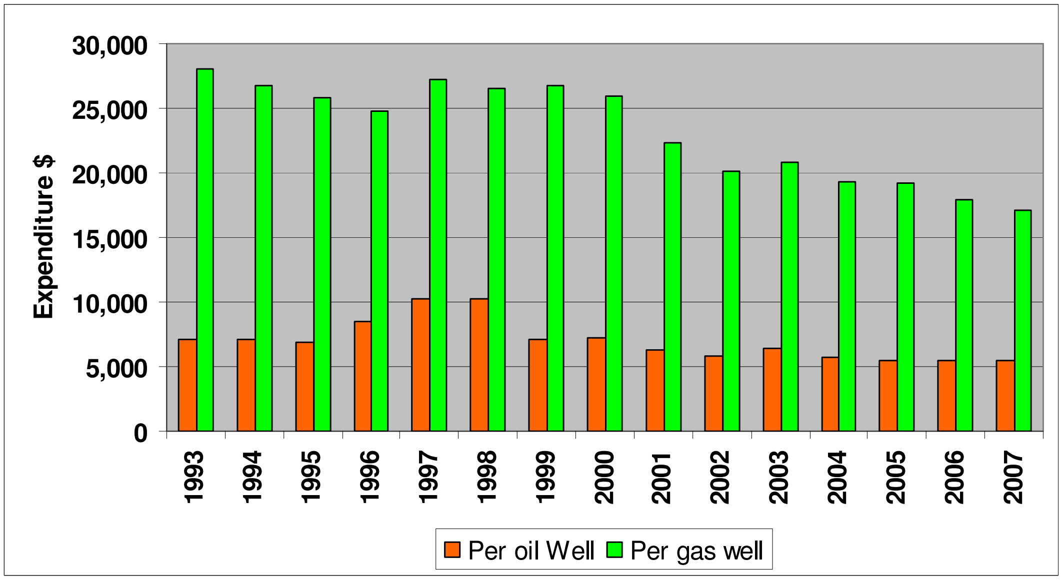



Source: CAPP, Statistical Handbook, September 2008.

<u>Operating Expenditure</u>

To estimate per well operating expenditures, CERI assumes that "wells and flow lines" operating expenditures (C1) for oil and gas are the same, and therefore divides C1 by the total cumulative combined oil and gas wells drilled. Gas plant operating expenditure (C2) per cumulative well is added to the operating expenditure of gas wells. This is illustrated in Figure 8.5.

**Figure 8.5**
**Ontario Oil and Gas Operating Expenditures per Cumulative Successful Well**
**1993-2007**




Source: CAPP, Statistical Handbook, September 2008.

Operating expenditures per gas well were higher than oil for each year, observed in Figure 8.5, in some cases quite dramatically. In 2007, operating expenditures per cumulative successful oil well were approximately $5,436 and gas well was $17,103. While operating expenditures per successful oil well have remained quite level, gas well operating expenditures have decreased every year since 1999.

## 8.2 Conventional Oil and Gas Resources

### 8.2.1 Economic Impacts

The resource, as described above, is small in comparison to other parts of Canada, making it not practical to calculate economic impacts. In addition crude oil and natural gas production is decreasing, in part due to the reduced levels of drilling activity.

## 8.3 Major Capital Projects

### 8.3.1 Background

The following table presents a summary of all major oil and gas projects announced in the province, as of Q1 2009. The table includes a brief description of the project, its cost and approximate timeline.

**Table 8.2**
**Summary of Ontario Major Oil and Gas Project Inventory**

| Project Name/Organization | Description | Cost ($million) | Time Duration |
|---|---|---|---|
| Dawn Storage Deliverability 7 | Increase of [up to] 47,000 hp of natural gas compression | 100 | 2008-2009 |
| Halton Hills Generating Station Pipeline Project | Natural gas pipeline serving a new 683 MW gas fired electricity generating plant | 23 | |

Source: http://spectraenergy.com/what_we_do/projects/

### 8.3.2 Economic Impacts

As with the oil and gas resources in Ontario, mentioned above, oil and gas projects are small, and make calculating economic impacts unfeasible. Tables 8.5 and 8.6 indicate this.

# CHAPTER 9
# ECONOMIC IMPACTS: QUÉBEC

This chapter discusses the economic impacts for the province of Québec. It is divided into three sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Québec. The following two sections discuss and review the economic impacts of unconventional oil resources and major capital projects in the province. Each section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 9.1 Background

As of 2007, there was no crude oil and natural gas production in Québec. That being said, the Utica Shale has huge potential for the province. This is discussed in greater detail in Section 9.2.

## 9.2 Shale Gas Resources

### 9.2.1 Background

While there is currently no commercial production, Québec's Utica Shale is attracting a lot of attention from North American E&P companies. It is important to note that particular shale formations have unique properties and characteristics, depending on porosity, thickness, brittleness and permeability. Many industry pundits, however, draw comparisons between Utica and Barnett shale in Texas, the most prolific shale formation in North America. Given its proximity to US Northeast markets, the gas could well command a premium to NYMEX, whereas the more developed shale plays in British Columbia are located far from consuming markets.

The Utica Shale is among the oldest and most widespread of black shales, stretching from Pennsylvania and New York to Québec. The shale play is generally characterized as Utica deep or Utica shallow. The former lies predominantly in at a depth range of 12-15,000 ft. and is located in the aforementioned US states, according to the USGS. The Québec shale play is, on the other hand, shallow (depth range of 2,300-6,000 ft.) and focuses on both sides of the St. Lawrence River, between Montréal and Québec City. Another large potential shale play in New York, Pennsylvania, West Virginia and eastern Ohio is the Marcellus shale. This geologic natural gas shale was reported to hold more then 1.9 Tcf back in 2002.[99]

The Quebec's Utica play is shallower than some of the other shales (such as the Barnett) and has pipeline infrastructure available. This is a drawback for more remote shale plays such as the Horn River basin in northeastern BC and southern Northwest Territories. While shallower than the Barnett shale in Texas, the Ordovician Utica shale has a thickness of 500 ft, while the Barnett

[99] http://www.oilshalegas.com/marcellusshale.html

ranges from 150 to 700 ft. The clay content, pressure gradient and gas-filled porosity are also comparable to the Barnett shale.

Table 9.1 illustrates the similar geological features between the two plays.

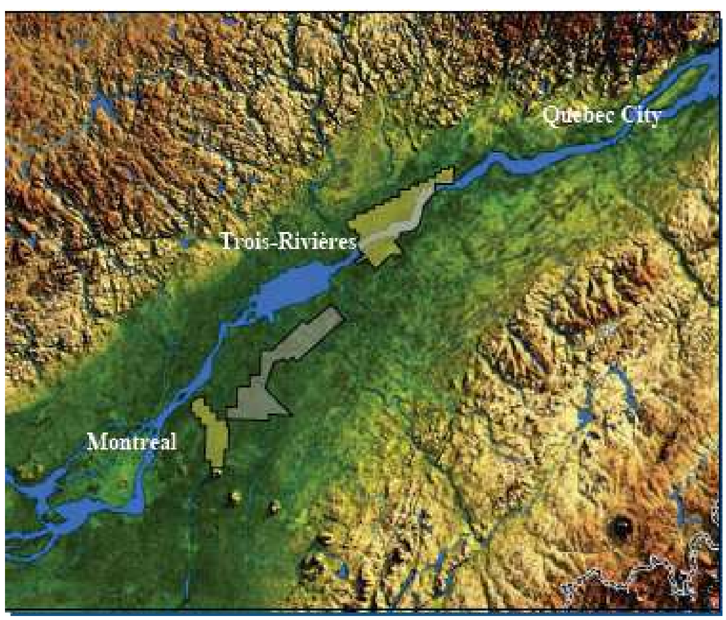
**Table 9.1**
**Comparing Geological Features**

| | **Utica** | **Barnett** |
|---|---|---|
| Depth (ft) | 2,300-6,000 | 4,500-9,000 |
| Thickness (ft) | 500 | 150-700 |
| Clay Content (%) | 15-26 | 15-30 |
| Gas-filled Porosity (%) | 3.2-3.7 | 3.0-4.8 |
| Pressure Gradient (psi/ft) | 0.45-0.60 | 0.46-0.50 |

Source: Forest Oil 2008 Analyst Conference, April 1, 2008.

Estimates in the Utica Shale ranges between 2 Tcf to up to 69 Tcf of natural gas located in this shale play. This would make it one of the largest in North America. Wellington West Capital Markets suggest that initial estimates of the resource potential play could be 25 Tcf of recoverable resource, with the best prospects lying within a corridor that runs parallel with the St. Lawrence River southeast of Montreal up to Québec City.[100]

**Figure 9.1**
**Location of Utica Shale**




Source: Forest Oil 2008Analyst Conference, April 1, 2008.

[100] Energy Strategy – The Utica Shale Gas Play, Part II, May 28, 2008.

The play is still in the exploratory stage, as initial testing is still underway. The main players are Talisman and Forest Oil, as well as several juniors.

Early in April 2008, Forest Oil announced the discovery of a new gas play in the Utica Shale in the St. Lawrence basin. Forest has close to 270,000 net lease acres over the 100 kilometers of the St. Lawrence River between Montréal and Québec City. The company believes the play has the potential to deliver as much as 4 Tcf into the area, based on two vertical well drilled in 2007 (tested rates up to 1,000 Mcfpd).[101] Forest has drilled three horizontal wells and was scheduled to begin fracking wells in the fourth quarter of 2008. There has not been an announcement whether fracture stimulation has commenced. Recall that due to the low permeability inherent in gas shales, stimulation is almost always required. This process requires substantial amounts of water and sand to allow the gas to flow to the wellbore. Forest expects full-scale development to occur in 2010, in spite of limited drilling and production history in the area.

Talisman Energy has 760,000 net acres in the St. Lawrence lowlands and is the largest active operator in the shale play. According to Talisman, the Gentilly well in the Utica shale was successful in September 2008. The well, located about 100 kilometers south of Québec City, flowed at 800,000 cubic feet a day. The Calgary-based company has three more wells planned for 2008.[102]

Announced in early April 2008, Pittsburgh, Pennsylvania-based Equitable Resources plans to drill up to two wells into the emerging natural gas play. One of the wells will be vertical while the other is horizontal.[103] Equitable has 200,000 prospective acres in the Utica Shale.

### 9.2.2 Economic Impacts

The resource as described above has been defined. However, with the limited amount of drilling, unknown land access and current economic climate, makes calculating economic impacts unfeasible, as indicated by Tables 9.2 and 9.3.

[101] Oil & Gas Exploration and Production: From Shale to Shining Shale, July 22, 2008.
[102] http://oilshalegas.com/uticashale.html
[103] http://oilshalegas.com/uticashale.html

**Table 9.2**
**Impacts Associated with Investment in Québec**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | - | - | - | - | - |
| **British Columbia** | - | - | - | - | - |
| **Manitoba** | - | - | - | - | - |
| **New Brunswick** | - | - | - | - | - |
| **Newfoundland & Labrador** | - | - | - | - | - |
| **Northwest Territories** | - | | | | - |
| **Nova Scotia** | - | | | | - |
| **Nunavut** | - | | | | - |
| **Ontario** | - | - | - | - | - |
| **Prince Edward Island** | - | - | - | - | - |
| **Quebec** | - | - | - | - | - |
| **Saskatchewan** | - | - | - | - | - |
| **Yukon Territory** | - | - | - | - | - |
| **Canada** | - | - | - | - | - |

**Insufficient data to perform analysis**

**Table 9.3**
**Impacts Associated with Operation in Québec**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | - | - | - | - | - |
| **British Columbia** | - | - | - | - | - |
| **Manitoba** | - | - | - | - | - |
| **New Brunswick** | - | - | - | - | - |
| **Newfoundland & Labrador** | - | - | - | - | - |
| **Northwest Territories** | - | - | - | - | - |
| **Nova Scotia** | - | | | | - |
| **Nunavut** | - | | | | - |
| **Ontario** | - | | | | - |
| **Prince Edward Island** | - | - | - | - | - |
| **Quebec** | - | - | - | - | - |
| **Saskatchewan** | - | - | - | - | - |
| **Yukon Territory** | - | - | - | - | - |
| **Canada** | - | - | - | - | - |

**Insufficient data to perform analysis**

## 9.3 Major Capital Projects

### 9.3.1 Background

The following table presents a summary of mid-stream oil and gas projects announced in the province, as of Q1 2009. The table includes a brief description of the projects, its cost and approximate timeline.

**Table 9.4**
**Summary of Quebec Major Oil and Gas Project Inventory**

| Project Name/Organization | Description | Cost ($million) | Time Duration |
|---|---|---|---|
| Rabaska LNG | LNG import terminal (Gasmetro and Enbridge) | 840 | 2014 |
| Cacouna Energy Terminal | LNG import terminal (Petro-Canada) | 1,000 | N/A |
| Energie Grande-Anse | | N/A | 2012 |

### 9.3.2 LNG/Terminal Developments

Québec is one of three Canadian provinces that are actively pursuing the construction of LNG facilities. Three facilities, all import terminals, are discussed in the following sections.

Project Rabaska – Quebec City (Import Terminal)

Gaz Metro, Enbridge and Gaz de France expressed interest in developing a new LNG re-gasification facility in Levis, Quebec. The Rabaska project is anticipated to cost $840 million and will include two large storage tanks with each able to hold 160,000 $m^3$ of LNG.[104] The plant will have an average capacity output of 500 MMcf/d.

The terminal will be connected to a newly constructed underground pipeline worth over $65 million which will extend approximately 42 km, with a maximum operating pressure of 9,930 kpa, and will feed the Trans Québec & Maritimes Pipeline (TQM) distribution station next to Jean-Lesage Highway in Saint-Nicolas.[105] From there, the TQM pipeline will supply natural gas to consumers across Québec and Eastern Ontario.

On May 2008, Russia's Gazprom had signed a Letter of Intent to join Rabaska's partnership and solely supply the terminal with natural gas produced from the soon to be developed Shtokman field located in the Barents Sea.[106] The construction phase is set to begin in 2010 and to be commercially operational by 2014, which will coincide with the development of the Shtokman gas field.

[104] Rabaska Project – Terminal: http://www.rabaska.net/project#terminal
[105] Rabaska Project – Pipeline: http://www.rabaska.net/project#pipeline
[106] Rabaska Project Press Release May 15, 2008: http://www.rabaska.net/docs/press-release_gazprom-rabaska_20080515.pdf

Cacouna Energy Terminal - Rivier-du-Loup (Import Terminal)

TransCanada Pipelines partnered with Petro-Canada to construct the Cacouna Energy facility in Québec, which will include the development of a LNG re-gasification terminal with two 160,000 $m^3$ storage tanks and a 240 km pipeline that will link the terminal to the existing TQM pipeline for distribution.[107] Gros Cacouna Island was strategically chosen for its location. This will minimize cost and delivery time. The facility will cost close to $1 billion and will have a send-out capacity of 500 million cubic feet per day.[108]

The project was awarded Federal and Provincial regulatory approval in June 2007. Construction of the terminal was to finish in 2009. Furthermore, Petro-Canada had already signed an agreement with Gazprom in March 2006 to construct a $3.5 billion liquefaction plant near St. Petersburg, namely the Baltic LNG project, in order to feed the Gros Cacouna terminal.[109] Two years later, however, Gazprom decided not to go ahead with the Baltic LNG project in a news release describing the execution of the project as "inexpedient" as they must focus on higher priority projects such as the construction of the Nord Stream pipeline and the development of the Shtokman field.[110] Recall that the Shtokman is supposed to be the source of LNG to the Rabaska project.

On December 31st 2008, Cacouna Energy announced on their website plans to close their Cacouna office for an indefinite period because of the shortage of LNG supplies.[111]

Energie Grande-Anse (Import Terminal)

Energie Grande-Anse Inc., a Quebec based company, is proposing to build a LNG import terminal in the Port of Grande-Anse along the Saguenay River in Québec. The project will be in collaboration with the Saguenay Port Authority, who owns the land where the terminal will be constructed.[112]

Construction of the 1 Bcf/day facility is intended to commence in the spring of 2009 and to come online mid-2012. The facility is estimated to create 1,200 direct and indirect jobs.

[107] Cacouna Energy – LNG Overview: http://www.energiecacouna.ca/en/pdfs/LNG_Overview.pdf
[108] Ibid : http://www.nrcan.gc.ca/eneene/sources/natnat/cacouna-eng.php
[109] DownStreamToday March 14, 2006: http://www.downstreamtoday.com/(X(1)S(l1kv55uwnwre1ebn024vehqg))/News/ArticlePrint.aspx?aid=621&AspxAutoDetectCookieSupport=1
[110] Gazprom Press Center, February 7 2008: http://www.gazprom.ru/eng/news/2008/02/26876.shtml
[111] Cacouna Energy Website: http://www.cacounaenergy.ca/en
[112] NRCAN Canadian LNG Import Project Status as of December 2008: http://www.nrcan-rncan.gc.ca/eneene/sources/natnat/grande-anse-eng.php

### 9.3.3 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 9.5 and 9.6, 80 percent of the impacts are directly related to Québec, with the remaining 20 percent being felt across the other provinces and territories.

**Table 9.5**
**Impacts Associated with Investment in Québec**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 19 | 0 | 3 | 2 | 1 |
| **British Columbia** | 20 | 0 | 5 | 3 | 3 |
| **Manitoba** | 6 | 0 | 2 | 1 | 1 |
| **New Brunswick** | 9 | 0 | 3 | 2 | 2 |
| **Newfoundland & Labrador** | 4 | 0 | 1 | 1 | 1 |
| **Northwest Territories** | 0 | 0 | 0 | 0 | 0 |
| **Nova Scotia** | 8 | 0 | 3 | 1 | 1 |
| **Nunavut** | 0 | 0 | 0 | 0 | 0 |
| **Ontario** | 93 | 2 | 24 | 12 | 12 |
| **Prince Edward Island** | 1 | 0 | 0 | 0 | 0 |
| **Quebec** | 882 | 15 | 273 | 118 | 156 |
| **Saskatchewan** | 5 | 0 | 1 | 1 | 1 |
| **Yukon Territory** | 0 | 0 | 0 | 0 | 0 |
| **Canada** | 1,048 | 17 | 317 | 140 | 177 |

**Table 9.6**
**Impacts Associated with Operation in Québec**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 25 | 0 | 4 | 3 | 2 |
| **British Columbia** | 25 | 0 | 7 | 4 | 3 |
| **Manitoba** | 9 | 0 | 3 | 1 | 2 |
| **New Brunswick** | 11 | 0 | 4 | 2 | 2 |
| **Newfoundland & Labrador** | 6 | 0 | 2 | 1 | 1 |
| **Northwest Territories** | 1 | 0 | 0 | 0 | 0 |
| **Nova Scotia** | 10 | 0 | 4 | 2 | 2 |
| **Nunavut** | 1 | 0 | 0 | 0 | 0 |
| **Ontario** | 135 | 2 | 35 | 17 | 18 |
| **Prince Edward Island** | 2 | 0 | 1 | 0 | 0 |
| **Quebec** | 758 | 15 | 235 | 101 | 134 |
| **Saskatchewan** | 7 | 0 | 2 | 1 | 1 |
| **Yukon Territory** | 0 | 0 | 0 | 0 | 0 |
| **Canada** | 990 | 19 | 296 | 132 | 164 |

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 9.2, Ontario receives 57 percent of the impacts, 11 percent for Alberta, 11 percent for British Columbia and 5 percent for New Brunswick. Figures 9.3 and 9.4 show the similar impacts on employment, and federal and provincial taxes.

**Figure 9.2**
**Total GDP Impacts ($million)**

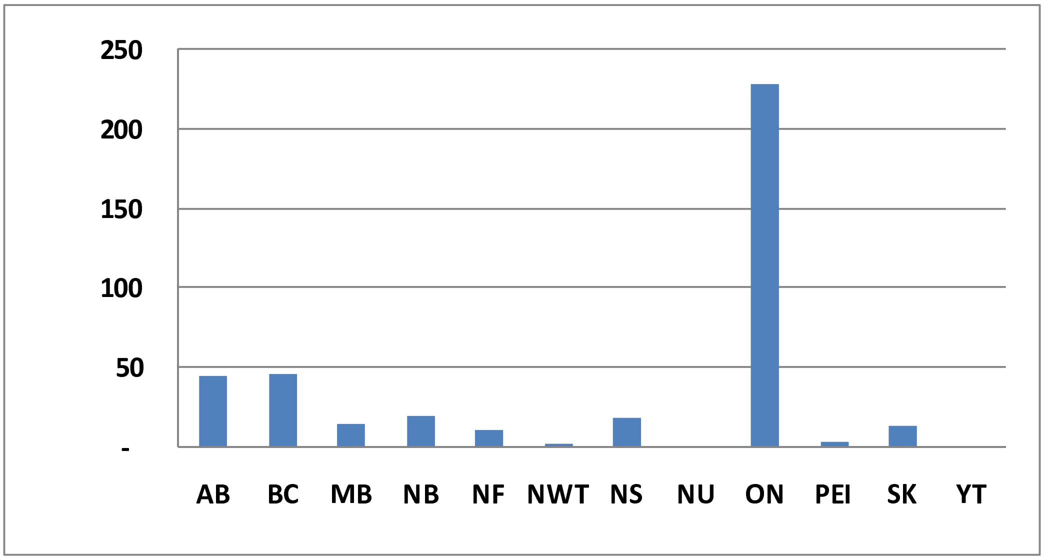



**Figure 9.3**
**Total Employment Impacts (thousand person years)**

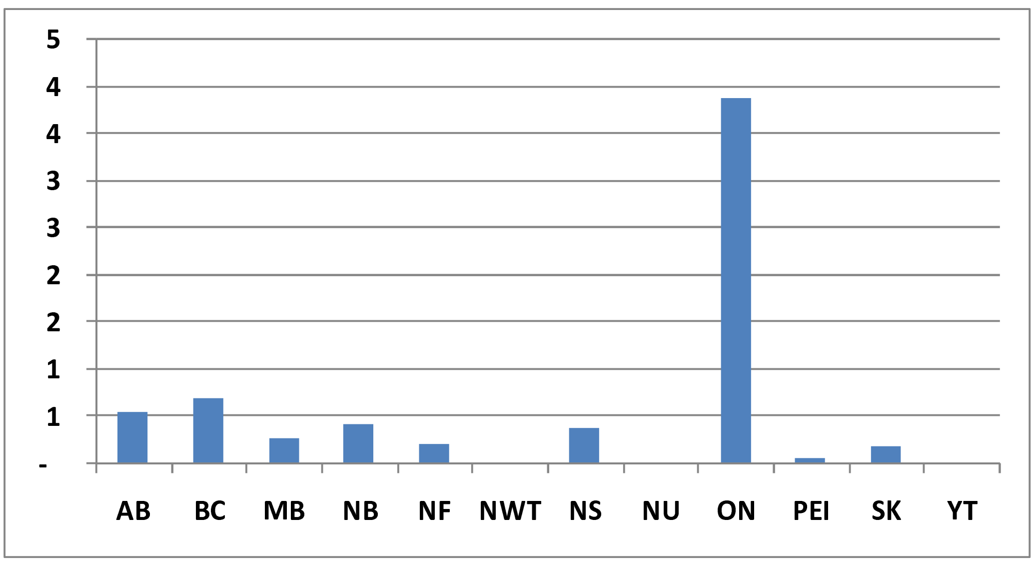
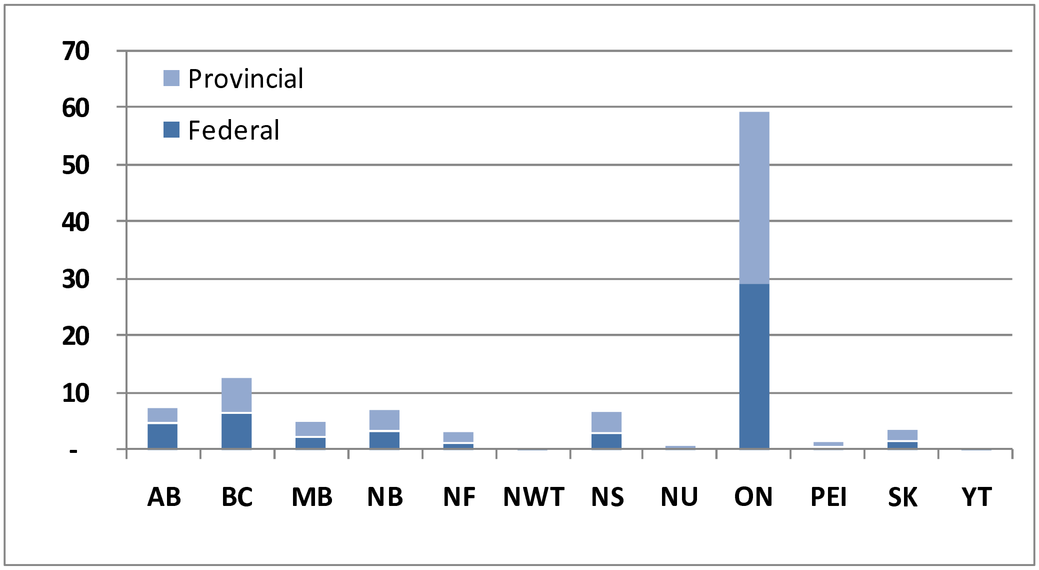


**Figure 9.4**
**Total Federal and Provincial Tax Impacts ($million)**



# CHAPTER 10
# ECONOMIC IMPACTS: NOVA SCOTIA

This chapter discusses the economic impacts for the province of Nova Scotia. It is divided into three sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Nova Scotia. The following two sections discuss and review the economic impacts of conventional gas resources and onshore CBM and Shale Gas resources in the province. Each section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 10.1 Background

This section describes the reserves, production, and expenditures of natural gas industry in Nova Scotia. In this section, the methodology that has been used for regrouping components of natural gas expenditures is demonstrated.

### 10.1.1 Reserves and Production

Currently the only producing field in Nova Scotia is the Sable Offshore Energy Project (SOEP) and encompasses one of the largest known natural gas deposits remaining to be developed in North America. The $3 billion project involves the development of six major natural gas fields that lie 10 to 40 kilometers north of the edge of the Scotian Shelf, near Sable Island, or approximately 225 kilometers off the east coast of Nova Scotia.

The six fields are: Venture, South Venture, Thebaud, North Triumph, Glenelg and Alma. Together, these fields contain an estimated 85 $m^3$ (3 Tcf) of recoverable gas reserves. According to the Nova Scotia Department of Energy, the shareholders of the Sable Project are ExxonMobil Canada Limited (50.8 percent), Shell Canada Limited (31.3 percent), Imperial Oil Limited (9.0 percent), Emera Inc. (8.4 percent) and Moshbacher Operating Limited (0.5 percent). The associated pipeline project is the Maritimes and Northeast Pipeline Project (M&NP), which is owned by Spectra Energy (77.5 percent), Emera Inc. (8.4 percent) and Moshbacher Operating Limited (0.5 percent).

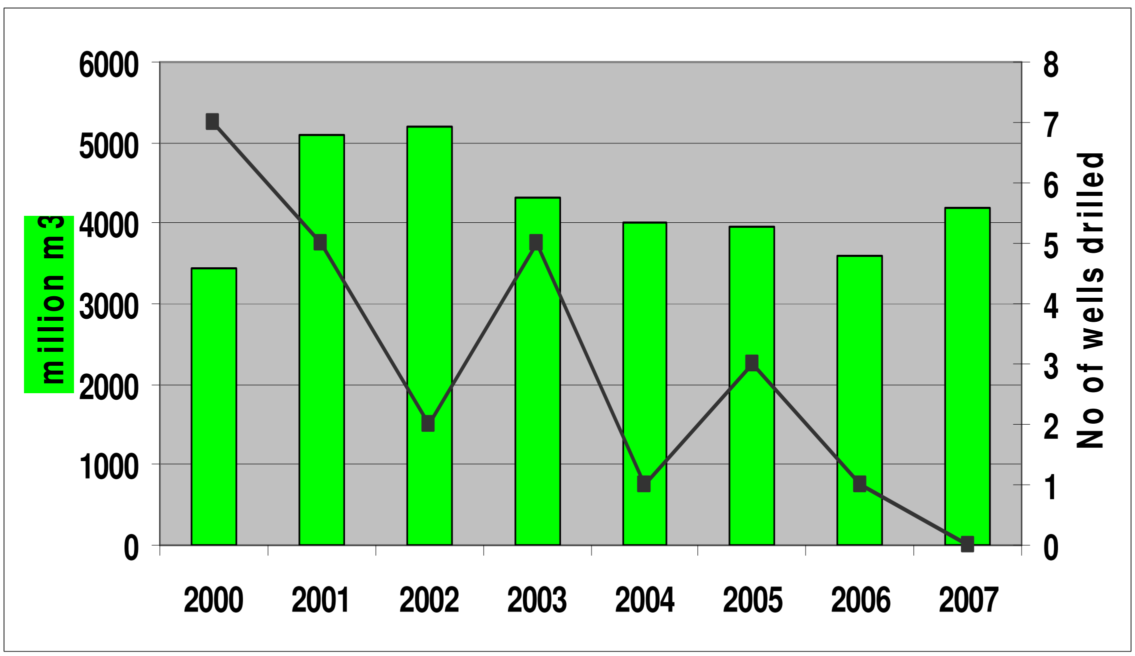
Production began in December of 1999 with a total project life expectancy of about 25 years; new discoveries may extend that project life. The project design rate is 14.4 million cubic meters per day of raw gas (550 MMcf/d) production yielding 13 $m^3$/d of sales gas. Approximately 3300 cubic meters of natural gas liquids will also be produced. This production rate can be increased if market conditions and gas supplies warrant. Unprocessed gas from Sable offshore fields is dehydrated at the Thebaud platform, and transport via subsea pipeline to a gas processing plant in Goldboro, Guysborough County, and then the processed gas moves through onshore pipelines to markets (eastern Canada and northeastern US).

Currently, five fields are connected and producing gas. These are Thebaud (1999), North Triumph (2000), Venture (2000), Alma (2003) and South Venture (2004). SOEP is being developed in two tiers. Thebaud, North Triumph and Venture were part of the Tier I, while Alma and South Venture are part of Tier II. Glenelg is presently under review.

Figure 10.1 illustrates Nova Scotia's natural gas production and the number of wells drilled between 2000 and 2007. With production commencing in late 1999, SOEP produced 3.4 billion $m^3$ of natural gas within its first year. Production peaked at 5.2 billion $m^3$ in 2002, and thereafter declined to 3.8 billion $m^3$ in 2006. Production rebounded to 4.4 million $m^3$ in 2007. For the period 2000 to 2007, Nova Scotia drilled 24 gas wells.

The recoverable natural gas reserve of Sable offshore is 85 billion $m^3$ and reserve production ratio is about 10 years.

**Figure 10.1**
**Nova Scotia Natural Gas Production and Number of Wells Drilled**
**2000 – 2007**




Source: CAPP, Statistical Handbook, September 2008.

While discussed in greater detail later in this Chapter, it is important to mention briefly the Deep Panuke Offshore project.[113] Expected to commence operations with 3.1 billion $m^3$ in 2010, the recoverable gas reserve of Deep Panuke is estimated at 17.6 billion $m^3$ (632 Bcf). The reserve production ratio is anticipated to be about 6 years. The Deep Panuke Offshore Gas field located approximately 250 km southeast of Halifax.

[113] Source: http://www.cnsopb.ns.ca/offshore_projects.php

### 10.1.2 Expenditures of the Petroleum Industry in Nova Scotia

The CAPP[114] reports the net cash expenditures[115] (investment) of Nova Scotia gas industry for exploration, development, operating and royalties as follows.

- A- Exploration
    - A1- Geological & Geophysical
    - A2- Drilling
    - A3- Land
- B- Development
    - B1- Drilling
    - B2- Field Equipment
    - B3- EOR
    - B4- Gas Plant
- C- Operating
    - C1- Wells & Flow lines
    - C2- Gas Plants
- D- Royalties

The CAPP also reports that in 2007, approximately $627 million were spent by the natural gas industry in Nova Scotia. The largest expenditures were for royalties, approximately 42 percent. Operating, exploration and development follow at 34 percent, 19 percent and 5 percent, respectively.

Table 10.1 summarizes the methodology that has been used for regrouping the components of the gas expenditures to the following categories: drilling investment expenditure, field equipment investment expenditure, operating expenditure and royalties.

**Table 10.1**
**Regrouping Natural Gas Investment Expenditures**

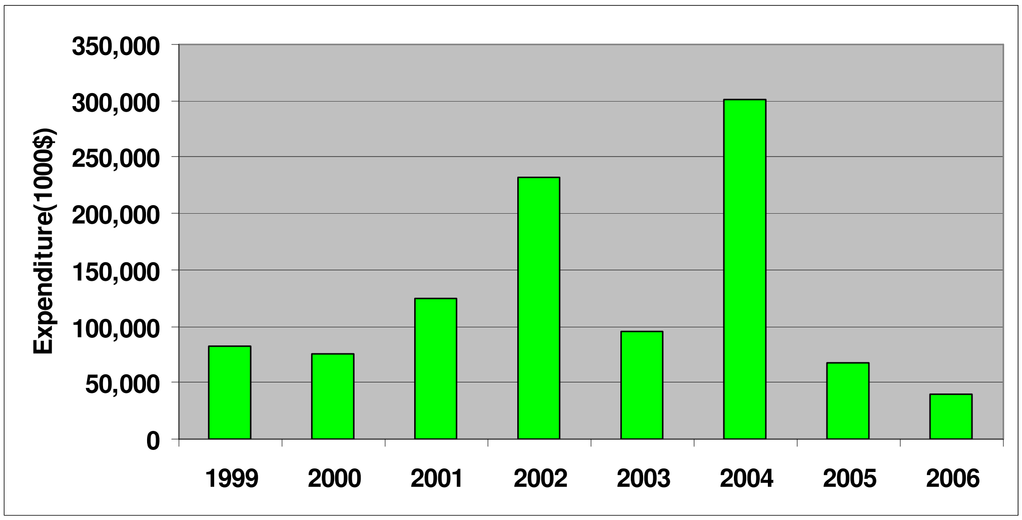
| |
|---|
| Drilling Investment Expenditure:<br>A1 + A2 + B1 |
| Field Equipment Expenditure:<br>B2 + B4 |
| Operating Expenditure:<br>C1+C2 |

[114] CAPP - TECHNICAL REPORT, Statistical Handbook, For Canada's Upstream Petroleum Industry, September 2008, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=132330
[115] Net cash expenditure exclude inter-industry transactions

Drilling Investment Expenditure

Nova Scotia, in total drilled 39 gas wells before production started in 1999. From 2000 to 2007, this province drilled an additional 24 gas wells.[116] Figure 10.2 shows drilling investment per gas well in Nova Scotia increased from $82 million in 1999 to maximum $301 million in 2004, and thereafter declined to $39 million in 2006 (no gas wells drilled in 2007).

**Figure 10.2**
**Nova Scotia Natural Gas Drilling Investment per Well Drilled**
**1999 - 2006**




Source: CAPP, Statistical Handbook, September 2008.

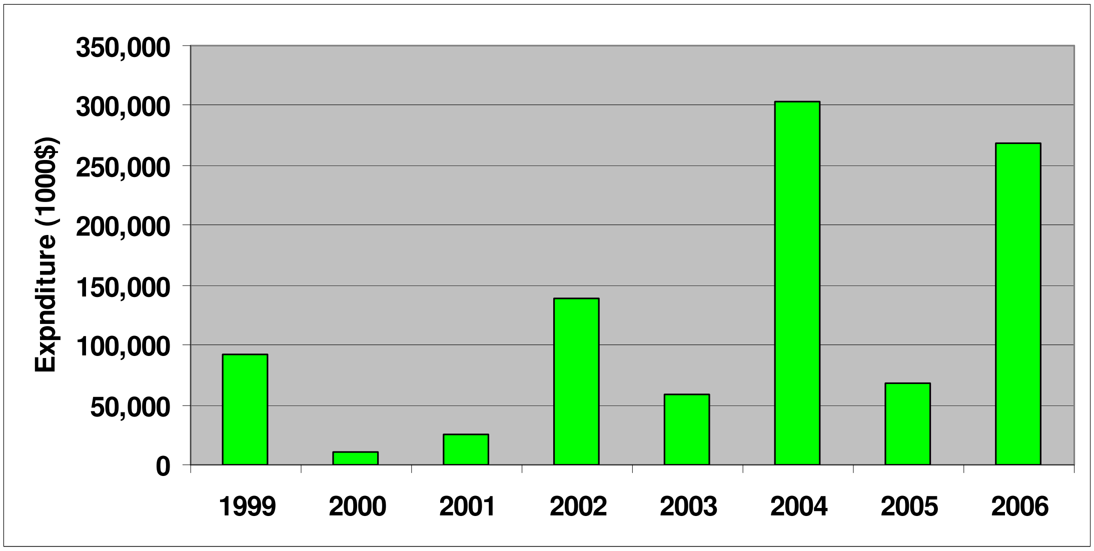
Field Investment Expenditure

The major part of field equipment investment includes expenditures of field facilities, and gathering systems.

Figure 10.3 illustrates Nova Scotia's natural gas field investment per well drilled between 1999 and 2006. Nova Scotia's field investment per gas well increased from $93 million in 1999 to $268 million in 2006, albeit investment fluctuated greatly.

[116] In 2006, Nova Scotia drilled one gas well with depth of 3,268 meters.

**Figure 10.3**
**Nova Scotia Natural Gas Field Investment per Well Drilled**
**1999-2006**

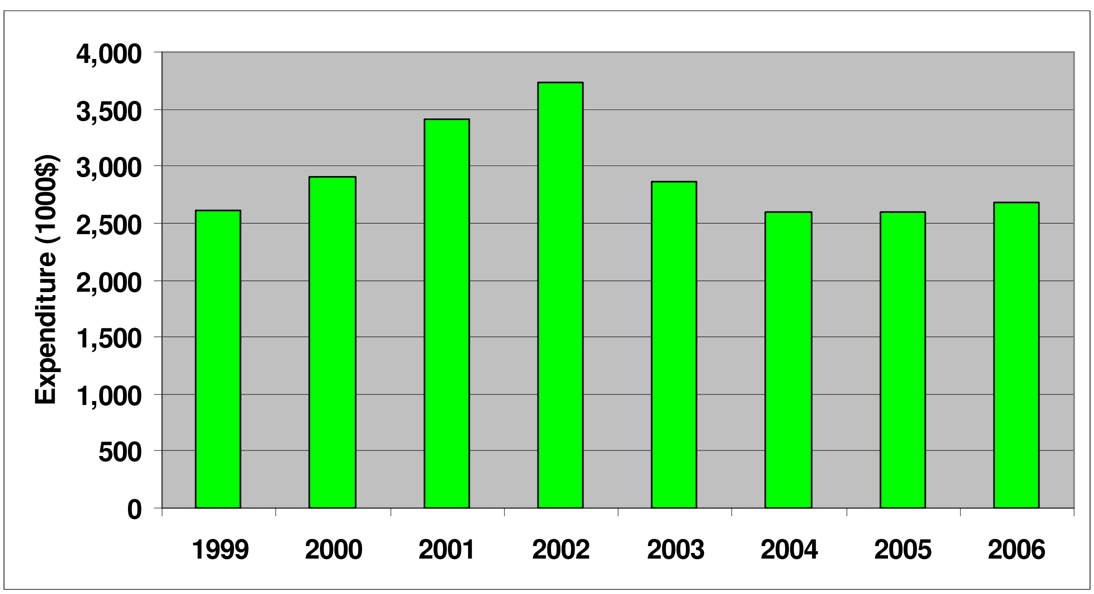



Source: CAPP, Statistical Handbook, September 2008.

<u>Operating Expenditure</u>

To estimate per well operating expenditures, CERI divides the sum of gas operation and gas plant expenditures by the total cumulative gas wells drilled. This is illustrated in Figure 10.4.

**Figure 10.4**
**Nova Scotia Natural Gas Operating Expenditures per Cumulative Successful Well**
**1999-2006**




Source: CAPP, Statistical Handbook, September 2008.

Figure 10.4 shows that gas-operating expenditures per gas well increased from $2.6 million in 1999 to $3.7 million in 2002. Gas-operating expenditures subsequently declined to $2.6 million in 2006.

## 10.2 Conventional Offshore Gas Resources

### 10.2.1 Background

The following section will discuss the Deep Panuke Offshore Gas Development.

Encana is now developing a new offshore gas play, Deep Panuke Offshore Gas Development. Located on the Scotian Shelf, approximately 250 km southeast of Halifax, Nova Scotia, Deep Panuke is expected to start production in 2010.

With an estimated 13 years of production life, the project taps into gas reservoirs underneath the Cohasset-Panuke oil field–Canada's first offshore project. The Cohasset-Panuke began operation in 1992 and ceased production in late 1999. It is currently being decommissioned.

Gas will be transported via sub sea pipeline to shore (Goldboro, NS) and eventually marketed to Canada and United States via the Maritimes and Northeast Pipeline. Capital construction costs for Deep Panuke are estimated at $700 million with an average annual production phase expenditures of approximately $150 million.[117] Recoverable sales gas is estimated at 632 Bcf.

### 10.2.2 Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 10.2 and 10.3, 82 percent of the impacts are directly related to Nova Scotia, with the remaining 18 percent being felt across the other provinces and territories.

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[117] Government of Nova Scotia website: http://www.gov.ns.ca/energy/oil-gas/offshore/current-activity/deep-panuke.asp

**Table 10.2**
**Impacts Associated with Investment in Nova Scotia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 44 | 0 | 7 | 5 | 3 |
| **British Columbia** | 32 | 0 | 9 | 5 | 4 |
| **Manitoba** | 2 | 0 | 1 | 0 | 0 |
| **New Brunswick** | 9 | 0 | 3 | 2 | 2 |
| **Newfoundland & Labrador** | 7 | 0 | 2 | 1 | 1 |
| **Northwest Territories** | 14 | 0 | 4 | 2 | 1 |
| **Nova Scotia** | 777 | 6 | 275 | 129 | 146 |
| **Nunavut** | 0 | 0 | 0 | 0 | 0 |
| **Ontario** | 40 | 1 | 10 | 5 | 5 |
| **Prince Edward Island** | 4 | 0 | 2 | 1 | 1 |
| **Quebec** | 15 | 0 | 5 | 2 | 3 |
| **Saskatchewan** | 5 | 0 | 1 | 1 | 1 |
| **Yukon Territory** | 0 | 0 | 0 | 0 | 0 |
| **Canada** | 951 | 8 | 319 | 152 | 167 |

**Table 10.3**
**Impacts Associated with Operation in Nova Scotia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 307 | 2 | 51 | 32 | 18 |
| **British Columbia** | 223 | 2 | 61 | 31 | 30 |
| **Manitoba** | 15 | 0 | 5 | 2 | 2 |
| **New Brunswick** | 60 | 1 | 21 | 10 | 11 |
| **Newfoundland & Labrador** | 52 | 1 | 16 | 7 | 9 |
| **Northwest Territories** | 97 | 0 | 25 | 16 | 8 |
| **Nova Scotia** | 5,368 | 39 | 1,897 | 889 | 1,008 |
| **Nunavut** | 2 | 0 | 1 | 1 | 0 |
| **Ontario** | 280 | 4 | 72 | 36 | 37 |
| **Prince Edward Island** | 28 | 1 | 11 | 5 | 6 |
| **Quebec** | 107 | 2 | 33 | 14 | 19 |
| **Saskatchewan** | 32 | 0 | 9 | 4 | 4 |
| **Yukon Territory** | 1 | 0 | 0 | 0 | 0 |
| **Canada** | 6,571 | 53 | 2,202 | 1,049 | 1,153 |

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 10.5, Alberta receives 26 percent of the impacts, 23 percent for Ontario, 19 percent for British Columbia and 9 percent for Quebec. Figures 10.6 and 10.7 show the similar impacts on employment, and federal and provincial taxes.

**Figure 10.5**
**Total GDP Impacts ($million)**

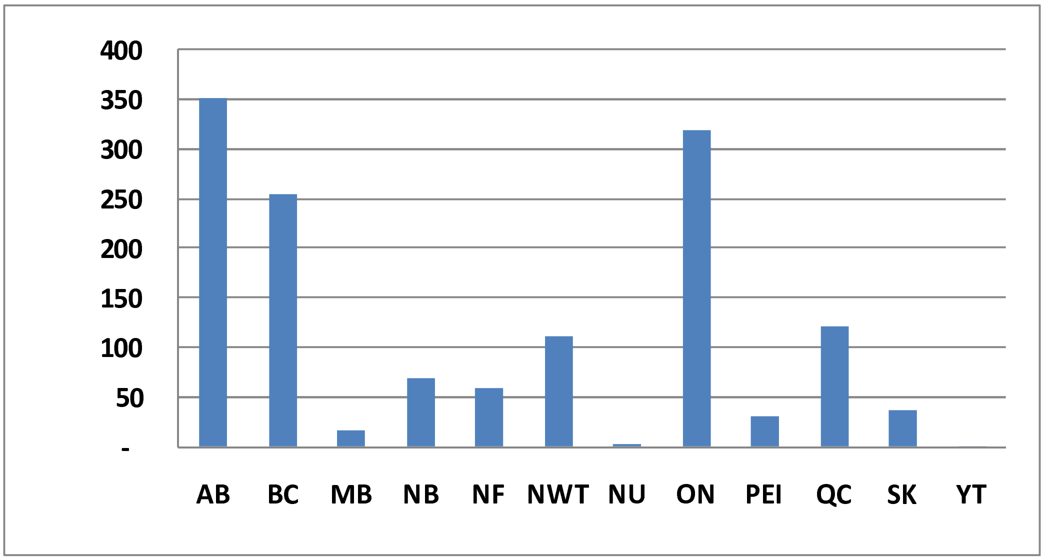



**Figure 10.6**
**Total Employment Impacts (thousand person years)**

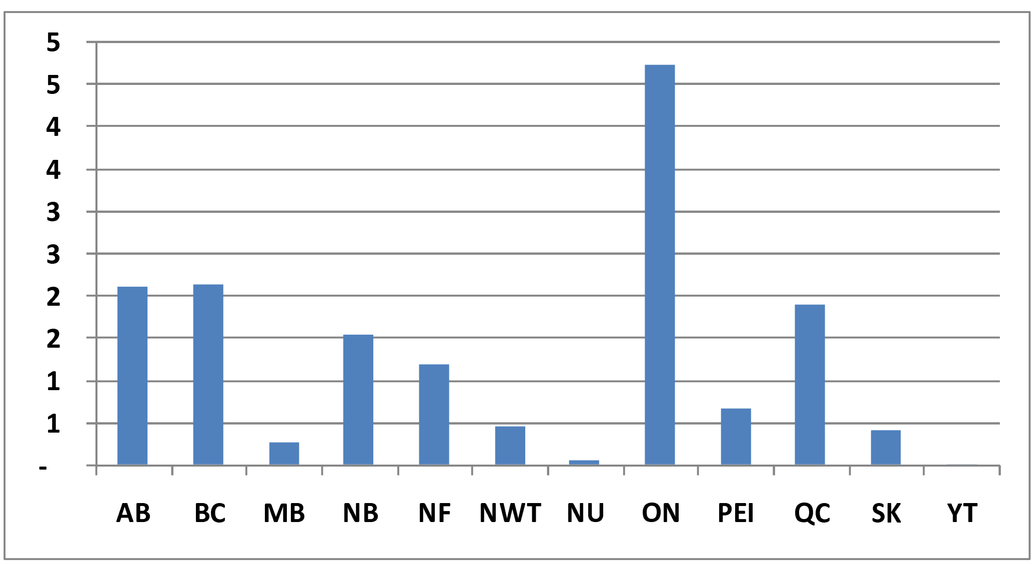
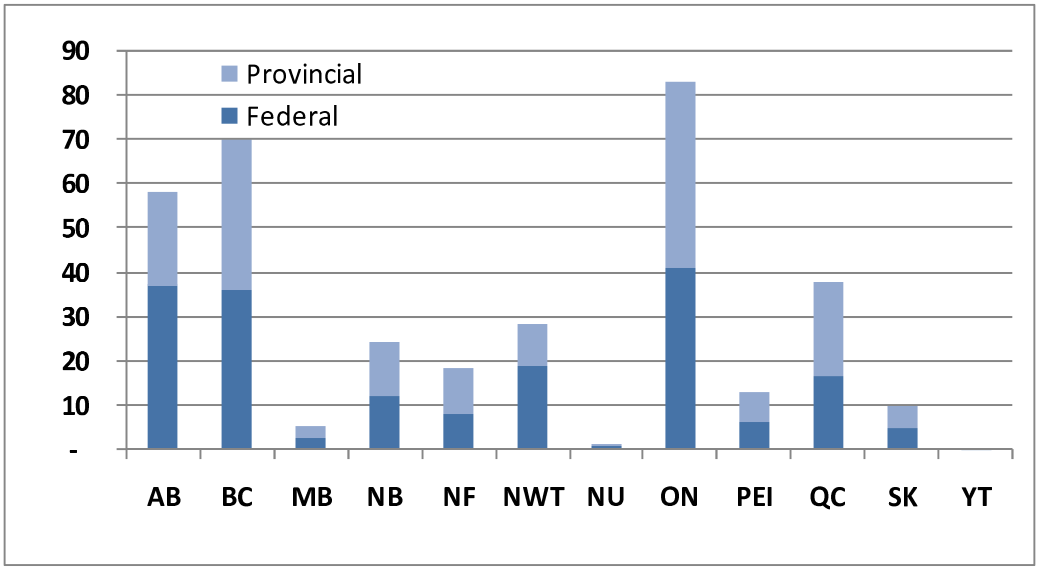


**Figure 10.7**
**Total Federal and Provincial Tax Impacts ($million)**




### 10.3 Onshore CBM and Shale Gas Resources

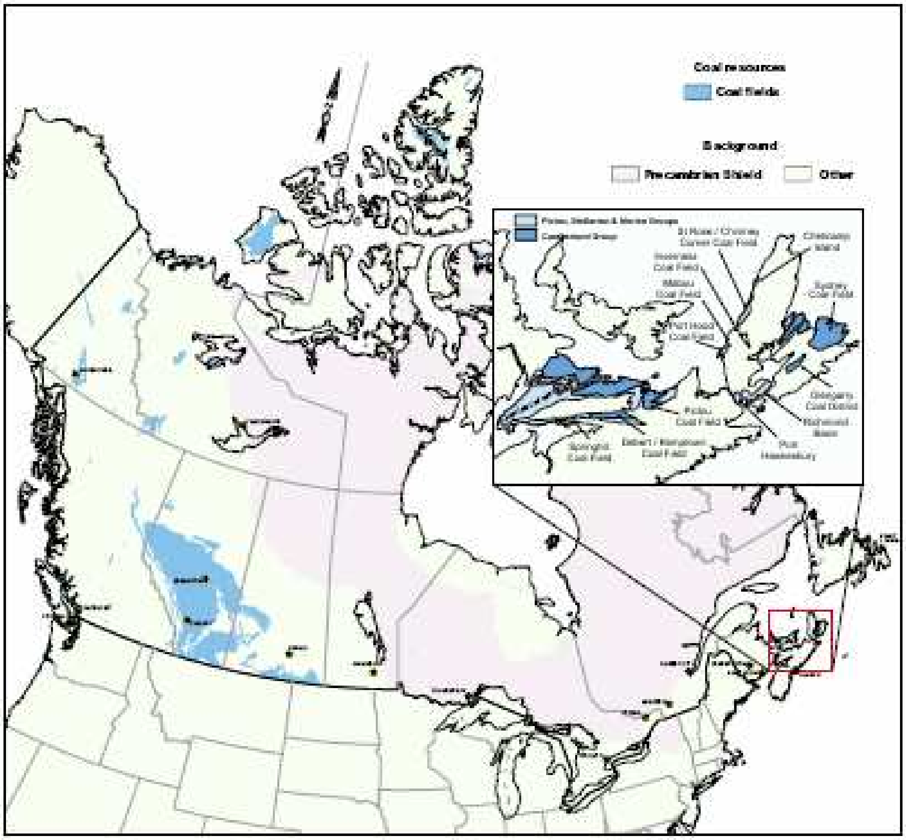
#### 10.3.1 Background

The following section discusses briefly two potential onshore developments, both regarded as unconventional, led by Stealth Ventures and Triangle Petroleum Corporation.

The Calgary-based Stealth Ventures holds the rights to explore CBM in the Stellarton and Springhill areas.[118] As mentioned in Chapter 4, coal deposits with the potential for CBM production are widespread in Canada, occurring in the coastal, foothills and mountain regions of British Columbia, the foothill and plains regions of Alberta and in Nova Scotia. Figure 10.8 illustrates this.

[118] http://www.gov.ns.ca/energy/oil-gas/onshore/current-activity/

**Figure 10.8**
**Surface Distribution of Coal Bearing Sediments in Canada**




Source: Canadian Gas Potential Committee, 2001.

In its 2001 report, the CGPC provided estimates of resources in Canada's coal deposits. For Nova Scotia, the CGPC provided a range of 6 to 18 Tcf and assigns a reliability factor of "low" to this estimate.

Currently, there is a $2 million commitment required to hold the lease beyond 2008, and Stealth is looking for partners. The Stellarton Basin is estimated to have 426 Bcf of resources in place.[119] A drill pad is already built with one drill location ready.

Triangle Petroleum is exploring Nova Scotia's potential for shale gas, or natural gas that is stored in organic rich rocks. While potential is significantly less than shale gas in British Columbia and Quebec, Nova Scotia's geology is attracting attention. In May 2007, Triangle announced its acquisition of a 516,000-acre parcel in Nova Scotia, called the Windsor Block. The area is located just 25 miles from the Maritimes and Northeast Pipeline. No costs are listed for the project. The Calgary-based company recently partnered up with Zodiac Exploration to explore the Windsor

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[119] Stealth Ventures Inc., Divestment Services: http://www.stealthventures.ca/pdf/StealthVentures_StellartonCBMProject.pdf

Block. Triangle is an exploration company that is currently active in the Fayetteville Shale project in Arkansas and the Barnett Shale project in Texas.

### 10.3.2 Economic Impacts

The resource as described above is in the process of being defined. The limited amount of drilling, unknown land access and current economic climate makes calculating economic impacts impractical. Tables 10.4 and 10.5 indicate this.

**Table 10.4**
**Impacts Associated with Investment in Nova Scotia**

| | $ million | Thousand Person Years | | $ million | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | - | - | - | - | - |
| **British Columbia** | - | - | - | - | - |
| **Manitoba** | - | - | - | - | - |
| **New Brunswick** | - | - | - | - | - |
| **Newfoundland & Labrador** | - | - | - | - | - |
| **Northwest Territories** | - | - | - | - | - |
| **Nova Scotia** | - | | | | - |
| **Nunavut** | - | | | | - |
| **Ontario** | - | | | | - |
| **Prince Edward Island** | - | - | - | - | - |
| **Quebec** | - | - | - | - | - |
| **Saskatchewan** | - | - | - | - | - |
| **Yukon Territory** | - | - | - | - | - |
| **Canada** | - | - | - | - | - |

**Insufficient data to perform analysis**

**Table 10.5**
**Impacts Associated with Operation in Nova Scotia**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | - | - | - | - | - |
| **British Columbia** | - | - | - | - | - |
| **Manitoba** | - | - | - | - | - |
| **New Brunswick** | - | - | - | - | - |
| **Newfoundland & Labrador** | - | - | - | - | - |
| **Northwest Territories** | - | | | | - |
| **Nova Scotia** | - | | | | - |
| **Nunavut** | - | | | | - |
| **Ontario** | - | - | - | - | - |
| **Prince Edward Island** | - | - | - | - | - |
| **Quebec** | - | - | - | - | - |
| **Saskatchewan** | - | - | - | - | - |
| **Yukon Territory** | - | - | - | - | - |
| **Canada** | - | - | - | - | - |

**Insufficient data to perform analysis**

# CHAPTER 11
# ECONOMIC IMPACTS: NEW BRUNSWICK

This chapter discusses the economic impacts for the province of New Brunswick. It is divided into three sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in New Brunswick. The following two sections discuss and review the economic impacts of conventional gas resources and major capital projects in the province. Each section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 11.1 Background

### 11.1.1 Reserves and Production

New Brunswick has a long history of crude oil and natural gas production. However, as of 2007 there has been little activity. Corridor Resources Inc. is operating at McCully Field, located near Sussex, in 2007. Two wells were drilled in the gas field. According to CAPP, in addition to the two wells, Corridor completed the construction of a field gathering system, a gas plant and a pipeline lateral connecting the McCully Field to markets through the Maritimes and Northeast Pipeline.[120] This occurred in mid-June 2007, as the company announced the region might have significant potential.

Canada's largest oil refinery, with a capacity of 250,000 barrels per day, is located in Saint John. It is important to note that the province is constructing Canada's first LNG facility—Canaport LNG, located in Saint John. This development is discussed in greater detail in Section 11.3.2.

## 11.2 Conventional Onshore Gas Resources

### 11.2.1 Economic Impacts

The resource as described above is in the process of being defined. The limited amount of drilling, unknown land access and current economic climate makes calculating economic impacts unfeasible.

[120] http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/NewBrunswick.aspx (March 31, 2009)

## 11.3 Major Capital Projects

### 11.3.1 Background

Table 11.1 presents a summary of mid-stream oil and gas projects announced in the province, as of Q1 2009. The table includes a brief description of the projects, its cost and approximate timeline.

**Table 11.1**
**Summary New Brunswick Major Oil and Gas Project Inventory**

| Project Name/Organization | Description | Cost ($million) | Time Duration |
|---|---|---|---|
| Brunswick Pipeline 5 | Emera to build 145 km pipeline from Saint John to Baileyville, Maine | 465 | 2007-2008 |
| Natural Gas Pipeline Expansion in NB | Maritimes and Northeast Pipelines (M&NP) to raise pipeline system capacity | 250 | |
| Project Eider Rock 4 | Development of a new petroleum refinery in Saint John that might process up to 300,000 barrels of crude oil per day | 8,000 | |

Source: http://www.irvingoil.com/company/erock.asp , Public Information Brochure, 11/27/08; APEC'S Major Projects Inventory 2008;

### 11.3.2 LNG/Terminal Developments

While there have been a half a dozen LNG facilities proposed at any given time, Canaport LNG at Saint John, New Brunswick will host Canada's first LNG re-gasification terminal. It is not, however, the only LNG facility proposed in the Maritime Provinces. Keltic Petrochemicals, located in Halifax, proposed a billion dollar petrochemical plant and a co-generation plant, while Maple LNG proposed an LNG re-gasification facility. The projects, located at Goldsboro, Nova Scotia, have been put on hold. It is assumed that Canaport has been accounted for in the base economy and is not included in the economic impacts. The following section, however, discusses Canaport LNG in greater detail.

Canaport – Saint John (Import Terminal)

The terminal is currently in the final stages of construction. As of February 2009, the terminal is approximately 94 percent complete and is expected to receive its first shipment of LNG at the end of the second quarter of 2009.[121]

Canaport LNG Limited was formed after Repsol YPF (75.0 percent) and Irving Oil (25.0 percent) signed an agreement in June 2005 to develop the LNG import terminal. Canaport LNG is responsible for construction, and eventual operation of the terminal.

[121] Canaport Project Journal 2009: http://www.canaportlng.com/project_journal_2009.php

The Canaport LNG import terminal will have a capacity of one billion cubic feet per day of natural gas, and will include three 160,000 $m^3$ LNG storage tanks with a throughput capacity of 600,000 $m^3$ of gas per hour.[122] Repsol will be responsible for supplying all LNG which will be initially be arriving from Trinidad & Tobago, while Irving Oil will market the re-gasified gas across Atlantic Canada.[123] Repsol will also help market the gas across Canada and the United States.

### 11.3.3 Economic Impacts

There is insufficient data to perform analysis for the project Eider Rock 4. While it considered a major project, detailed information is unavailable. Tables 11.2 and 11.3 illustrate this.

**Table 11.2**
**Impacts Associated with Investment in New Brunswick**

| | $ million | Thousand Person Years | | $ million | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | - | - | - | - | - |
| **British Columbia** | - | - | - | - | - |
| **Manitoba** | - | - | - | - | - |
| **New Brunswick** | - | - | - | - | - |
| **Newfoundland & Labrador** | - | - | - | - | - |
| **Northwest Territories** | | | | | |
| **Nova Scotia** | Insufficient data to perform analysis | | | | |
| **Nunavut** | | | | | |
| **Ontario** | | | | | |
| **Prince Edward Island** | - | - | - | - | - |
| **Quebec** | - | - | - | - | - |
| **Saskatchewan** | - | - | - | - | - |
| **Yukon Territory** | - | - | - | - | - |
| **Canada** | - | - | - | - | - |

122 Canaport LNG: http://www.canaportlng.com/pdfs/who_we_are.pdf
123 Ibid

**Table 11.3**
**Impacts Associated with Operation in New Brunswick**

| | $ million | Thousand Person Years | | $ million | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | - | - | - | - | - |
| **British Columbia** | - | - | - | - | - |
| **Manitoba** | - | - | - | - | - |
| **New Brunswick** | - | - | - | - | - |
| **Newfoundland & Labrador** | - | - | - | - | - |
| **Northwest Territories** | | | | | |
| **Nova Scotia** | | | | | |
| **Nunavut** | | | | | |
| **Ontario** | | | | | |
| **Prince Edward Island** | - | - | - | - | - |
| **Quebec** | - | - | - | - | - |
| **Saskatchewan** | - | - | - | - | - |
| **Yukon Territory** | - | - | - | - | - |
| **Canada** | - | - | - | - | - |

Insufficient data to perform analysis

# CHAPTER 12
# ECONOMIC IMPACTS: PRINCE EDWARD ISLAND

## 12.1 Background

In terms of the oil and gas industry, Prince Edward Island is most famous for drilling the first offshore well back in 1943.[124] With that being said, the industry is very much still in its infancy.

As of 2007, there was no crude oil and natural gas production on Prince Edward Island.

According to the provincial government, PEI may have significant sources of natural gas, including one significant resource find made offshore at East Point.[125] There are currently no producing fields, but exploration activities have been increasing as of late. Approximately only 20 exploratory wells have been drilled. As such, the province's hydrocarbon potential has not really been assessed.

[124] http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/PrinceEdwardIsland.aspx (March 31, 2009)
[125] http://www.gov.pe.ca/enveng/gas/index.php3 (March 31, 2009)

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# CHAPTER 13
# ECONOMIC IMPACTS: NEWFOUNDLAND & LABRADOR

This chapter discusses the economic impacts for the province of Newfoundland & Labrador. It is divided into two sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Newfoundland & Labrador. The remaining sections discuss and review the economic impacts of conventional oil and gas resources, and major capital projects in the province. This chapter is unique in that conventional oil and gas resources are combined, due to the fact that they are co-produced offshore. Each section describes briefly that particular resource, forecasts and their economic impacts on the province and the rest of Canada's provinces. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 13.1 Background

This section describes the reserves, productions, and expenditures of crude oil industry in Newfoundland & Labrador. In this section, the methodology that has been used for regrouping components of oil expenditures is demonstrated.

### 13.1.1 Reserves and Production

The following section reviews existing oil projects in Newfoundland & Labrador. As such it discusses three offshore projects: Hibernia, Terra Nova and White Rose.[126]

Located 315 km east of St. John's, the Hibernia oil field was discovered in 1979, within the Jeanne d'Arc Basin in the northeastern portion of the Grand Banks. The Hibernia offshore oil field is owned jointly by the following: ExxonMobil Canada (33.1 percent), Chevron Canada Resources (26.9 percent), Petro-Canada (20 percent), Canada Hibernia Holding Corporation (8.5 percent), Murphy Oil (6.5 percent) and StatoilHydro Canada Ltd (5 percent). Production commenced in late 1997, with 1.2 million barrels of crude oil being produced. Production increased substantially to 46.6 million barrels in 2008.

Terra Nova, located 350 km east of St. John's, is also found within the Jeanne d'Arc Basin. The large field was discovered by Petro-Canada in 1984. The Terra Nova offshore oil field is owned by the following: Petro-Canada (33.9 percent), Exxon Mobil Canada Properties (22.0 percent), Norsk Hydro Canada Oil & Gas (15.0 percent), Husky Energy Operations Ltd. (12.5 percent), Murphy Oil Company Ltd. (12.0 percent), Mosbacher Operating Ltd. (3.5 percent) and Chevron Canada Resources (1.0 percent). Production of this project began in 2002 with 38.4 million barrels of crude oil. In 2008, Terra Nova produced 34.4 million barrels of oil.

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[126] CAPP (Paul Barnes) - Newfoundland & Labrador oil and Gas Industry Outlook, January 24, 2008. http://www.capp.ca/getdoc.aspx?DocID=131357

White Rose was also discovered in 1984 and is located 350 km east of St. John's. The field, like Terra Nova and Hibernia, is situated in the Jeanne d'Arc Basin. Husky Energy (72.5 percent) and Petro-Canada (27.5 percent) are working interest partners in the project. White Rose reserves have been estimated at 283 million barrels of oil. Production of White Rose commenced in 2005 with 2.4 million barrels of crude oil and increased to 33 million barrels in 2008.

Figure 13.1 illustrates Newfoundland's crude oil production and number of wells drilled between 1997 and 2007. Production of offshore Newfoundland & Labrador commenced in 1997 at 1.2 million barrels per year and increased to 134 million barrels in 2007 and thereafter declined to 114.5 million bbl in 2008 (not shown).[127] Over the same period, the number of wells drilled increased from 4 wells in 1997, peaked at 15 wells in 2003, and thereafter declined to 2 wells in 2007.

Oil production of Hibernia, Terra Nova, and White Rose totaled 84.6 million barrels in the first eight months of 2008, a 9.2 percent decrease year-on-year. According to the "Oil Production Bulletin", an online publication from the Government of Newfoundland and Labrador's website, the reason for this decrease was due to a significant decline in production at the White Rose and Terra Nova fields.[128]

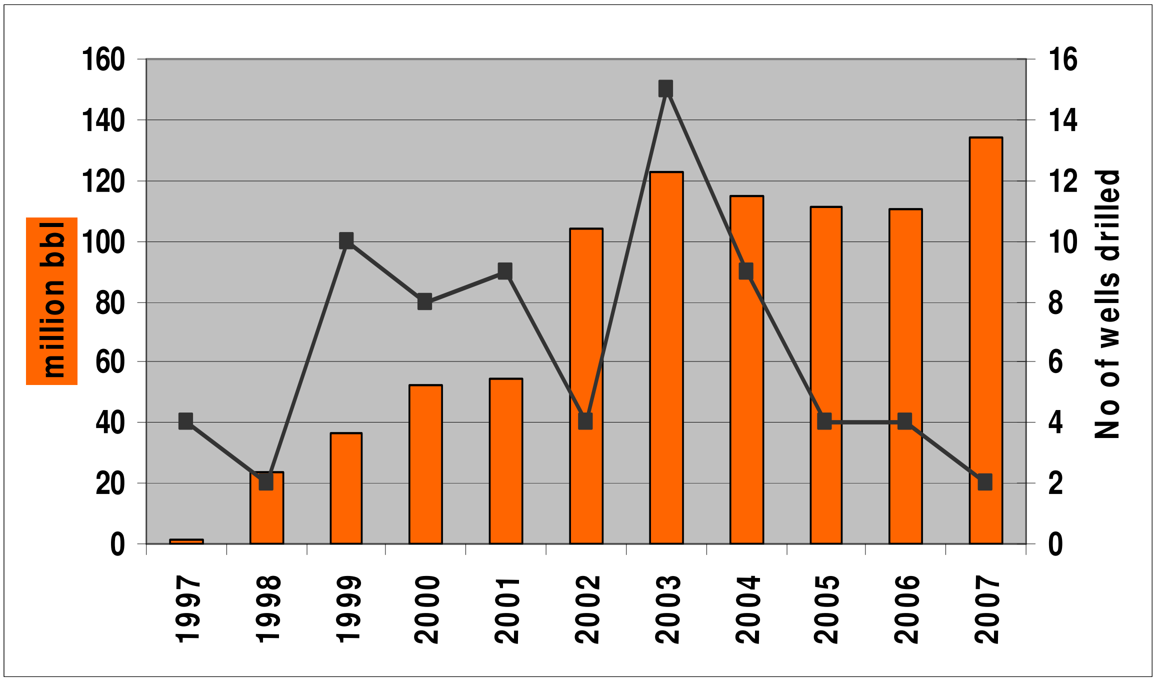
For the same period (January to August 2008), White Rose produced 24.6 million barrels, while Terra Nova produced 26.8 million barrels of oil. This is a decline of 13.8 percent and 12.6 percent respectively year-on-year. Hibernia, on the other hand, saw only a 2.3 percent decline from 2007, with a total of 33.2 million barrels of oil. Figure 13.1 summarizes production of the three offshore fields.

The reserves are estimated to be 1.8 billion barrels, and the production ratio is approximately 16 years.

[127] Canada Newfoundland offshore Petroleum Board – Cumulative Production http://www.cnlopb.nl.ca/pdfs/off_prod.pdf

[128] Economic Research and Analysis Division, Government of Newfoundland and Labrador: "Oil Production Bulletin". http://www.economics.gov.nl.ca/bulletins/oil.asp

**Figure 13.1**
**Newfoundland Crude Oil Production and Number of Wells Drilled**
**1997 - 2007**




Source: CAPP, Statistical Handbook, September 2008.

One of the potential future projects for Newfoundland & Labrador is offshore Hebron reserve with 581 million barrels of heavy oil (discovered in 1981). The future of this project is discussed in greater detail in Section 13.2.

### 13.1.2 Offshore Newfoundland & Labrador Oil Expenditures

The CAPP[129] reports the net cash expenditures[130] (investment) of Newfoundland oil industry for exploration, development, operating and royalties as follows.

- A- Exploration
  - A1- Geological & Geophysical
  - A2- Drilling
  - A3- Land
- B- Development
  - B1- Drilling
  - B2- Field Equipment
  - B3- EOR
  - B4- Gas Plant
- C- Operating
  - C1- Wells & Flow lines
  - C2- Gas Plants

[129] CAPP - TECHNICAL REPORT, Statistical Handbook, For Canada's Upstream Petroleum Industry, September 2008, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=132330

[130] Net cash expenditure exclude inter-industry transactions

The CAPP also reports that in 2007, approximately $2.6 billion were spent by the petroleum industry in Newfoundland and Labrador. The largest expenditures were for royalties, at approximately 46 percent. Development, operating and exploration follow at 25 percent, 21 percent and 8 percent, respectively.

Table 13.1 summarizes the methodology that has been used for regrouping the components of oil expenditures to the following categories: drilling investment expenditure, field equipment investment expenditure, operating expenditure and royalties and fees.

**Table 13.1**
**Regrouping Crude Oil Industry Expenditures**

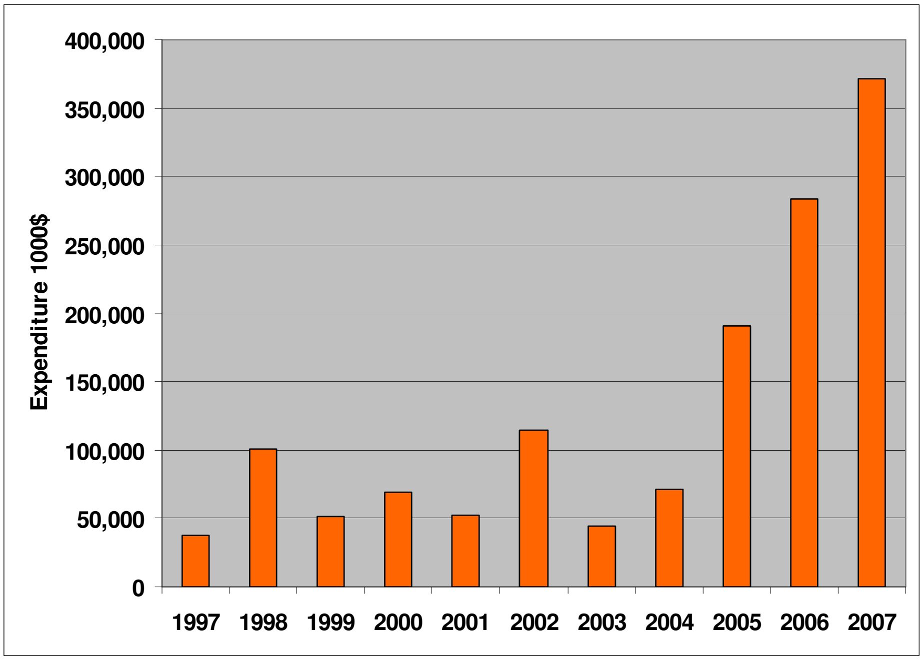
| |
|---|
| Drilling Investment Expenditure:<br>A1 + A2 + B1 |
| Field Equipment Expenditure:<br>B2 + B3 |
| Operating Expenditure:<br>C1 |

Drilling Investment Expenditure

Between 1979 and 2007, CAPP reports a total of 45 oil wells. Recall that Newfoundland's first oil well drilled was in 1979, even though production did not commence until 1997. In 2007, Newfoundland drilled 2 offshore oil wells, with a total depth of 11,402 meters. Drilling expenditures of the petroleum industry are taken from CAPP's Statistical Handbook, released in September 2008. These expenditures are disaggregated into oil and gas in proportion to meters oil and gas drilled wells.

Figure 13.2 illustrates Newfoundland's oil drilling investment per well drilled between 1997 and 2007. The figure shows that the drilling investment per well in Newfoundland increased from $38 million in 1997 to $371 million in 2007.

**Figure 13.2**
**Newfoundland Oil Drilling Investment per Well Drilled**
**1997 - 2007**

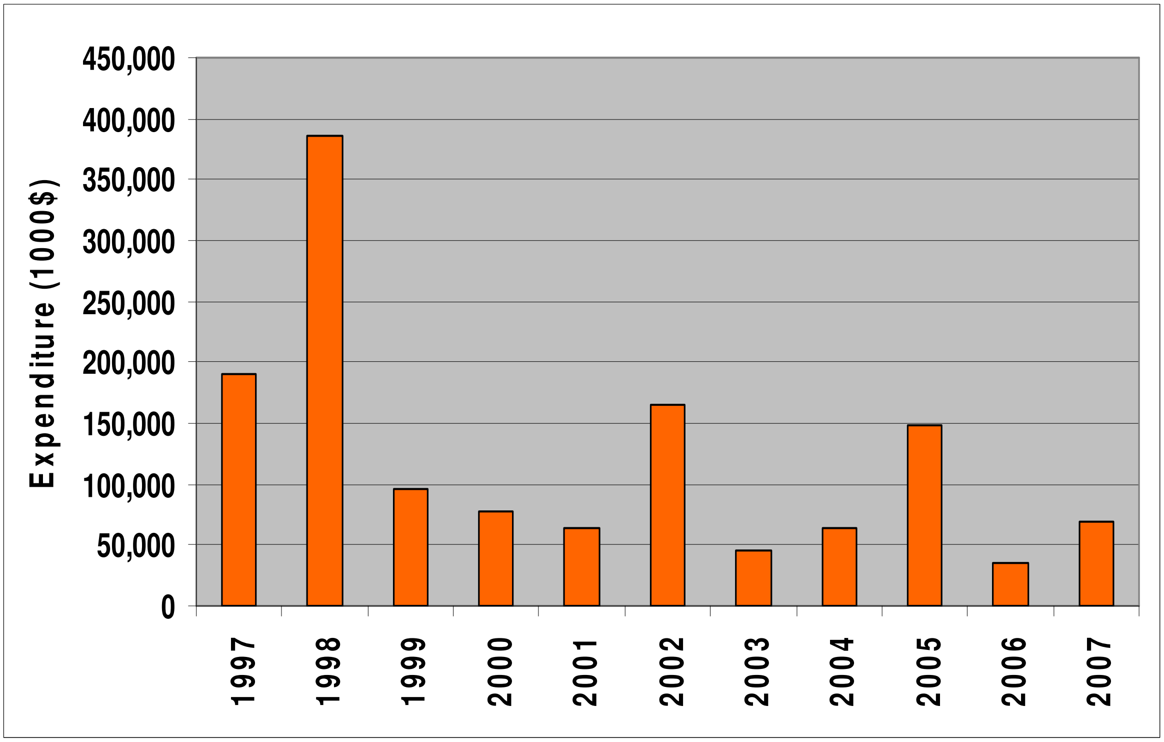



Source: CAPP, Statistical Handbook, September 2008.

Field Investment Expenditure

The major part of field equipment expenditures results from field facilities, crude oil battery and gathering systems. Figure 13.3 illustrates the fluctuating pattern of Newfoundland's field investment. Newfoundland's field investment per oil peaked at $385 million in 1998 and, thereafter, declined to $35 million in 2006. In 2007, field investment per oil well was $70 million.

**Figure 13.3**
**Newfoundland Oil Field Investment per Well Drilled**
**1997-2007**

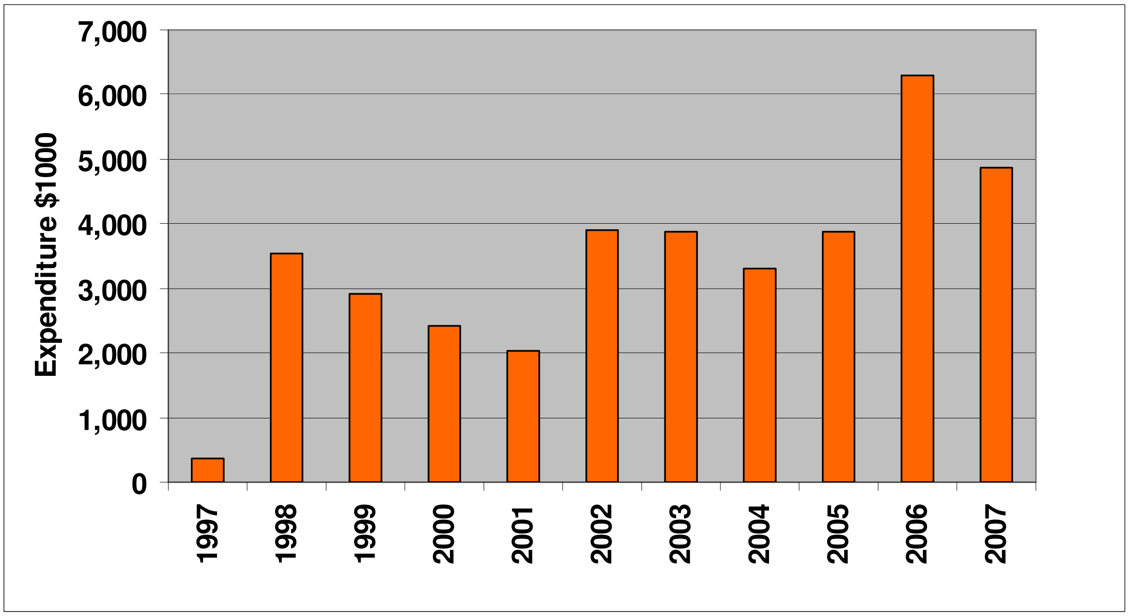



Source: CAPP, Statistical Handbook, September 2008.

<u>Operating Expenditure</u>

To estimate per well operating expenditures, CERI divides oil operation expenditures (C1) by the total cumulative oil wells drilled. This is illustrated in Figure 13.4.

**Figure 13.4**
**Newfoundland Oil Operating Expenditures per Cumulative Successful Well**
**1997-2007**




Source: CAPP, Statistical Handbook, September 2008.

In 2007, operating expenditure per oil well was $4.8 million per cumulative successful well. Operating expenditures per oil well peaked in 2006 at over $6 million.

## 13.2 Conventional Oil (& Associated Gas) Resources

### 13.2.1 Offshore Resources

This section reviews briefly, several future projects and expansions of existing projects. The "Economic Review 2007", also published by the Government of Newfoundland & Labrador, reports that the approval of the province to expand White Rose is expected to produce an additional 24 million barrels of oil from an area known as South White Rose Extension. According to the Development Plan Amendment, Husky Oil committed to spend $595 million in capital costs.[131]

Hebron oil field, discovered in 1981, is estimated to have 400-700 million barrels of resources.[132] The government of Newfoundland & Labrador announced on August 2008 that it had reached a Memorandum of Understanding (MOU) with the Hebron-Ben Nevis proponents to develop the oil field. The partners are Exxon Mobil Canada (operator), Chevron Canada, Petro-Canada and Norsk Hydro Canada. Under the MOU, the province will take a 4.9 percent equity stake in the project

[131] Government of Newfoundland and Labrador, Economic Research and Analysis Division, "The Economic Review 2007". www.economics.gov.nl.ca
[132] http://www.chevron.ca/operations/exploration/atlantic.asp

which is projected to cost $110 million. It is predicted that production of the estimated 700 million barrel reservoir will commence by late 2014 or early 2015.

Other exploration highlights include:[133]

- Drilling of the Great Barasway F-66 well in the Orphan Basin was terminated in April 2007. Partners working on the Orphan Basin are committed to returning to the Basin in 2008 or 2009 to resume exploration and drilling.
- ConocoPhillips and partners have identified potential drilling targets in the Laurentain Basin (gas-directed) after positive evaluation of the 3-D seismic data.

### 13.2.2 Major Capital Projects

Table 13.2 presents a summary of mid-stream oil and gas projects announced in the province, as of Q1 2009. The table includes a brief description of the projects, its cost and approximate timeline.

**Table 13.2**
**Summary of Newfoundland & Labrador Major Oil and Gas Project Inventory**

| Project Name | Description | Cost ($million) | Time Duration |
|---|---|---|---|
| Offshore Exploration | 39 exploration licenses in offshore; Husky Energy, Petro-Canada and Stat Oil Hydro Canada to drill wells in 2009 | 819 | 2007-2012 |
| Terra Nova Capital Expenditures | Includes ongoing capital expenditures; production came to 42 million barrels in 2007 afar shutdown in 2006 | 150 | 2008 |
| Hibernia South Expansion | Proposal for 223 million barrels expansion rejected in 2007 | | |
| Hebron/Ben Nevis Oil Field | Fourth producing oilfield off Newfoundland coast | 5,000 | 2010-2014 |
| Offshore Natural Gas Project | Husky Energy researching production and transportation of natural gas from White Rose field | | |
| West Bonne Bay Oil and Gas Field | Delineation well drilled on field in 2006 by Norsk Hydro and Husky Energy | | |

Source: 5 APEC'S Major Projects Inventory 2008.

### 13.2.3 Economic Impacts

With respect to the Hebron/Ben Nevis expansion, CERI encountered difficulty with obtaining valid operating costs for the project and thus could not complete the analysis. In addition, the royalty framework for this project was unknown at the time of analysis, and has only been made public recently.

[133] Government of Newfoundland and Labrador, Economic Research and Analysis Division, "The Economic Review 2007". www.economics.gov.nl.ca

# CHAPTER 14
# ECONOMIC IMPACTS: NORTH OF 60

This chapter discusses the economic impacts for Canada's three northern territories: Yukon Territory, Northwest Territories (NWT) and Nunavut. This chapter is titled *North of 60,* to simply incorporate all three territories. However, the economic impacts of each territory will be separated. As such, this chapter is structured differently. It is divided into five sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in the three territories. The data is, unfortunately aggregated. The second section discusses in greater detail, oil and gas resources for each of the territories.

The following three sections, one for each of the territories, discuss and review the economic impacts of conventional oil and gas resources, and major capital projects in the Yukon Territory, Northwest Territories and Nunavut. Each section describes briefly that particular resource, forecasts, and their economic impacts on the province and the rest of Canada's provinces. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, and federal and provincial taxes are discussed.

## 14.1 Background

This section describes the reserves, production, and expenditures of the petroleum industry in the Territories and Arctic Island. This section compiles the data of Yukon Territory, Northwest Territories and Nunavut in one jurisdiction. Hence forth in this section "Territories" refers to above areas. In this section, the methodology that has been used for regrouping components of the petroleum industry's expenditures, and their disaggregation into oil and natural gas is demonstrated.

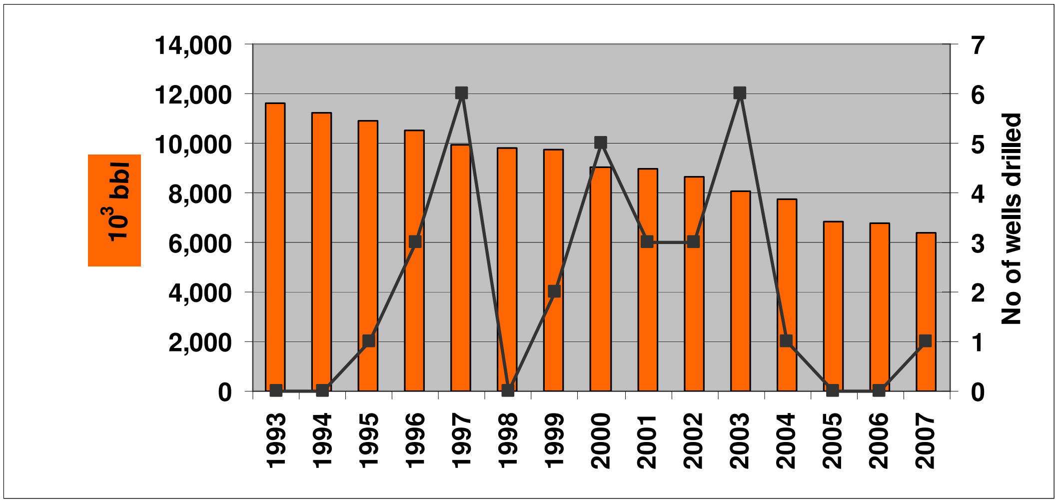
### 14.1.1 Reserves and Production

According to the Canadian Association of Petroleum Producers (CAPP), as of December 2006, the remaining established reserves of crude oil in the Territories are approximately 30 million barrels. This is a net decrease of 16.5 percent from 2005.

The Territories produced 6.3 million barrels crude oil in 2007, which was almost half of 1993 production. Figure 14.1 illustrates crude oil production and the number of wells drilled. Crude oil production has decreased in consecutive years from 1993 to 2007. In 2007, the crude oil reserves production ratio was about 5 years.

In the last three years only one oil well was drilled and completed in the Territories.

**Figure 14.1**
**Territories Crude Oil Production and Number of Wells Drilled**
**1993 - 2007**



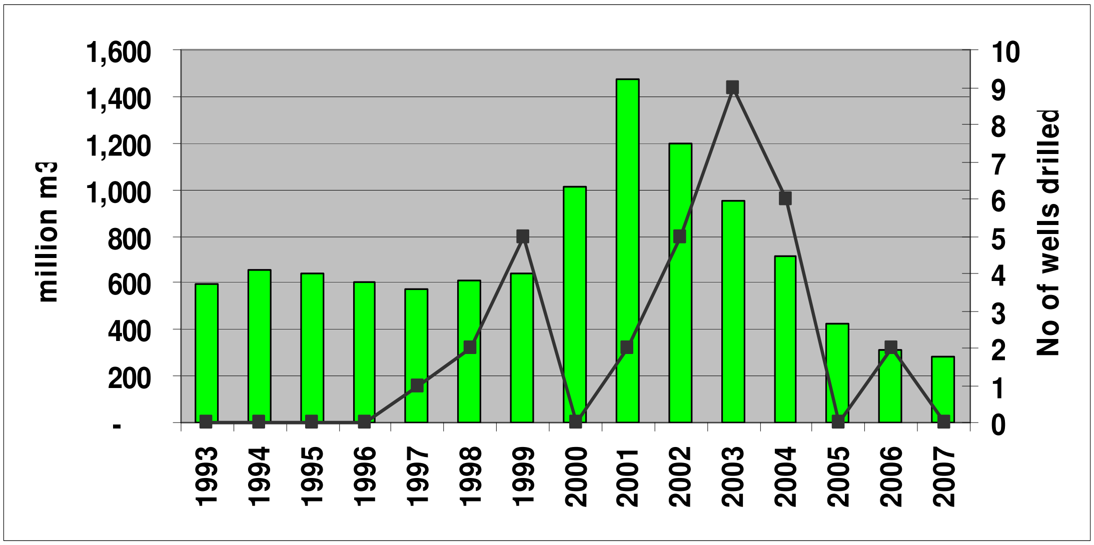

Source: CAPP, Statistical Handbook, September 2008.

The National Energy Board (NEB)[134] reports, as of December 2006, the remaining established reserves of marketable natural gas at 3.2 trillion $m^3$ [135] (115 Tcf) for Northern Canada. The NEB estimates includes Mackenzie Delta and Beaufort Sea (225 billion $m^3$), mainland Northwest and Yukon Territories (28 billion $m^3$), and Arctic Islands (340 billion $m^3$).

Figure 14.2 illustrates marketable natural gas production and the number of wells drilled between 1993 and 2007. Over this time period, marketable natural gas production for the Territories peaked at 1,471 million $m^3$ in 2001, and thereafter declined to 285 million $m^3$ in 2007. Between 2001 and 2007, marketable natural gas production representing an average annual decline rate of 24 percent. Over the same period, 24 gas wells were drilled and completed. There was no drilling in 2005 and 2007.

[134] A Report by the Canadian Gas Potential Committee, Volume 2, 2005
[135] CAPP reports the remaining established reserves of territories at 10.2 billion cubic meters (see CAPP - TECHNICAL REPORT, Statistical Handbook)

**Figure 14.2**
**Territories Marketable Natural Gas Production and Number of Wells Drilled**
**1993 - 2007**




Source: CAPP, Statistical Handbook, September 2008.

### 14.1.2 Expenditures of the Petroleum Industry for North of 60

The CAPP[136] reports the net cash expenditures[137] of the Territories petroleum industry for exploration, development, operating and royalties as follows.

A- Exploration
- A1- Geological & Geophysical
- A2- Drilling
- A3- Land

B- Development
- B1- Drilling
- B2- Field Equipment
- B3- EOR
- B4- Gas Plant

C- Operating
- C1- Wells & Flow lines
- C2- Gas Plants

The CAPP also reports that in 2007, $417 million was spent in the Territories by the petroleum industry. The largest expenditures were for exploration, approximately 50 percent. Development, operating and royalties follow at 28 percent, 14 percent and 8 percent, respectively.

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[136] CAPP - TECHNICAL REPORT, Statistical Handbook, For Canada's Upstream Petroleum Industry September 2008, http://www.capp.ca/raw.asp?x=1&dt=NTV&dn=132330

[137] Net cash expenditure exclude inter-industry transactions

Table 14.1 summarizes the methodology that has been used for regrouping the components of the petroleum expenditures to the following categories: drilling investment expenditure, field equipment investment expenditure, operating expenditure and royalties and fees expenditure.

**Table 14.1**
**Disaggregating Oil and Gas Expenditures**

| Crude Oil | Natural Gas |
|---|---|
| Drilling Expenditure:<br>A1 + A2 + B1 | Drilling Expenditure:<br>A1 + A2 + B1 |
| Field Equipment Expenditure:<br>B2 + B3 | Field Equipment Expenditure:<br>B2 + B4 |
| Operating Expenditure:<br>C1 | Operating Expenditure:<br>C1 + C2 |

Drilling Investment Expenditure

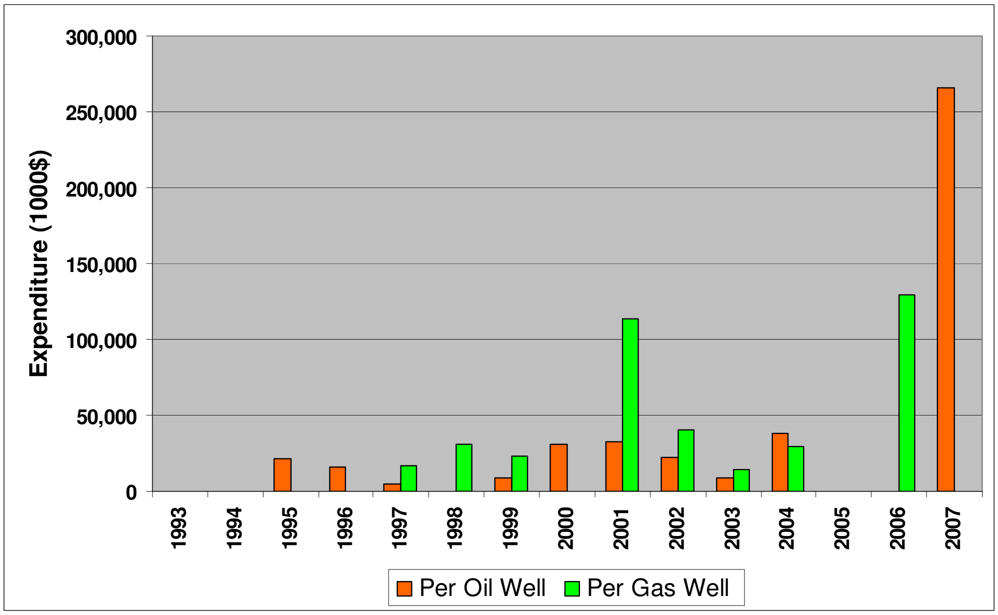
The Territories drilled two gas wells and no oil wells in 2006. In 2007, the Territories drilled one oil well and no gas wells. The total depth of drilled gas and oil wells was 4,612 meters and 1,562 meters, respectively. CAPP also reports 225 cumulative oil wells drilled and 141 gas wells drilled in year 2007.

Drilling investment expenditures of the petroleum industry (A1, A2, and B1) is taken from the CAPP report and they are disaggregated into oil and gas in proportion to meters oil and gas drilled wells.

Figure 14.1 illustrates the Territories drilling investment per oil and natural gas well. This graph shows that in 2006 and 2007, the Territories spent approximately $129 million and $265 million for per gas and per oil well drilled, respectively.

It should be noted that Figure 14.3 illustrates drilling expenditures for per completed well (commercial) and not those wells that are drilled, tested, and capped (non-commercial). Therefore, there is a possibility that the Territories had drilling expenditures for a specific year (2005) but no successful wells. In this case, all wells drilled were not completed so their expenditures have not been taken into account.

**Figure 14.3**
**Territories Oil and Gas Drilling Investment per Well Drilled**
**1993 - 2007**



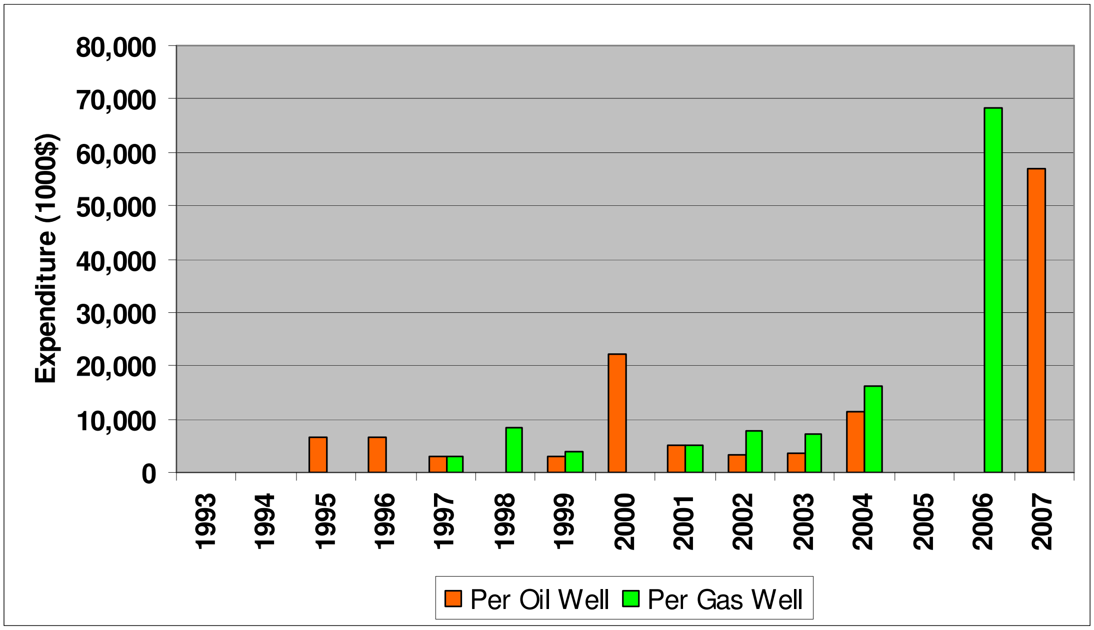

Source: CAPP, Statistical Handbook, September 2008.

Field Investment Expenditure

The major part of field equipment investment results from; the expenditure of field facilities, crude oil battery, and gathering systems. CAPP reports combined oil and gas field equipment investment expenditure (B2). CERI has disaggregated the above investment into oil and gas in proportion to the number of wells drilled. The enhanced oil recovery expenditure (B3) was added to oil field investment; similarly, gas plant expenditure (B4) was added to the gas field investment (Table 14.1).

From 2005 to 2007, field investment per gas and oil well was approximately $68 million and $57 million, respectively. This is illustrated in Figure 14.4. Similar to drilling expenditures, there is a possibility that the Territories had field expenditures for a specific year (2005) but no successful wells. In this case, all wells drilled were not completed so their expenditures have not been taken into account.

**Figure 14.4**
**Territories Oil and Gas Field Investment per Well Drilled**
**1993-2007**

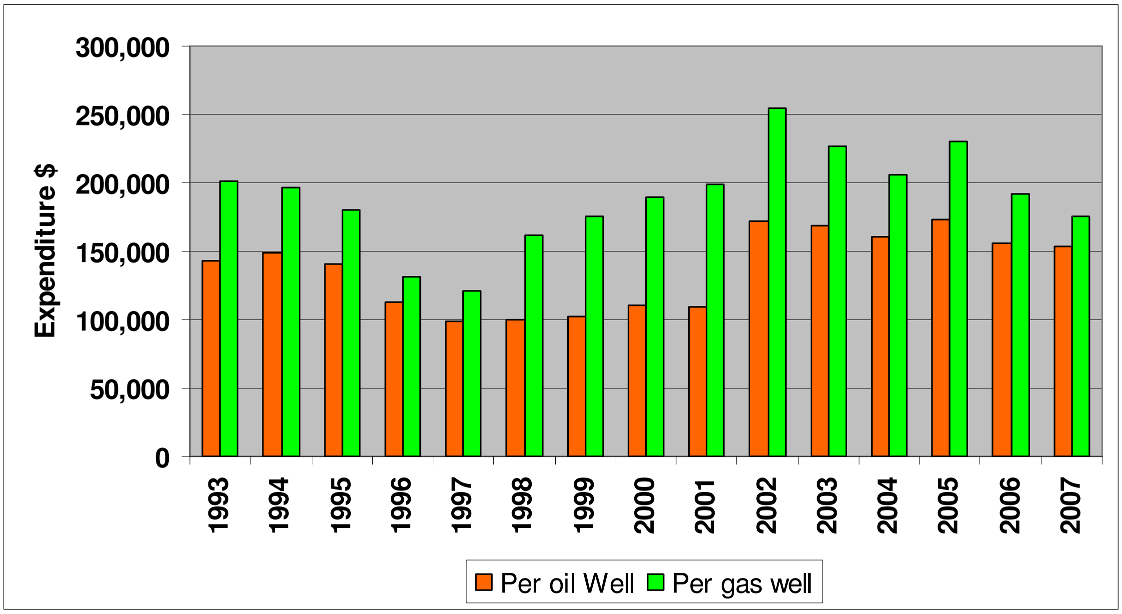



Source: CAPP, Statistical Handbook, September 2008.

Operating Expenditure

To estimate per well operating expenditures, CERI assumes that "wells and flow lines" operating expenditures (C1) for oil and gas are the same, and therefore divides C1 by the total cumulative combined oil and gas wells drilled. Gas plant operating expenditure (C2) per cumulative well is added to the operating expenditure of gas wells. This is illustrated in Figure 14.5.

**Figure 14.5**
**Territories Oil and Gas Operating Expenditures per Cumulative Successful Well**
**1993-2007**




Source: CAPP, Statistical Handbook, September 2008.

From 1993 to 2007, operating expenditures per gas well were higher than oil. In 2007, operating expenditures per cumulative successful gas well were approximately $175,307 while operating expenditures per cumulative successful oil well were $153,434.

### 14.2 Oil & Gas Resources

Canada has remarkable oil and gas resources north of the 60° North latitude. The region and basins containing the resources are often known as the Northern Canada Sedimentary Basin, and include all three territories. This enormous area occupies approximately 2.5 million square kilometers.[138] This is illustrated in Figure 14.6. The following three sections discuss oil and gas resources in the Northwest Territories, Yukon Territory and Nunavut.

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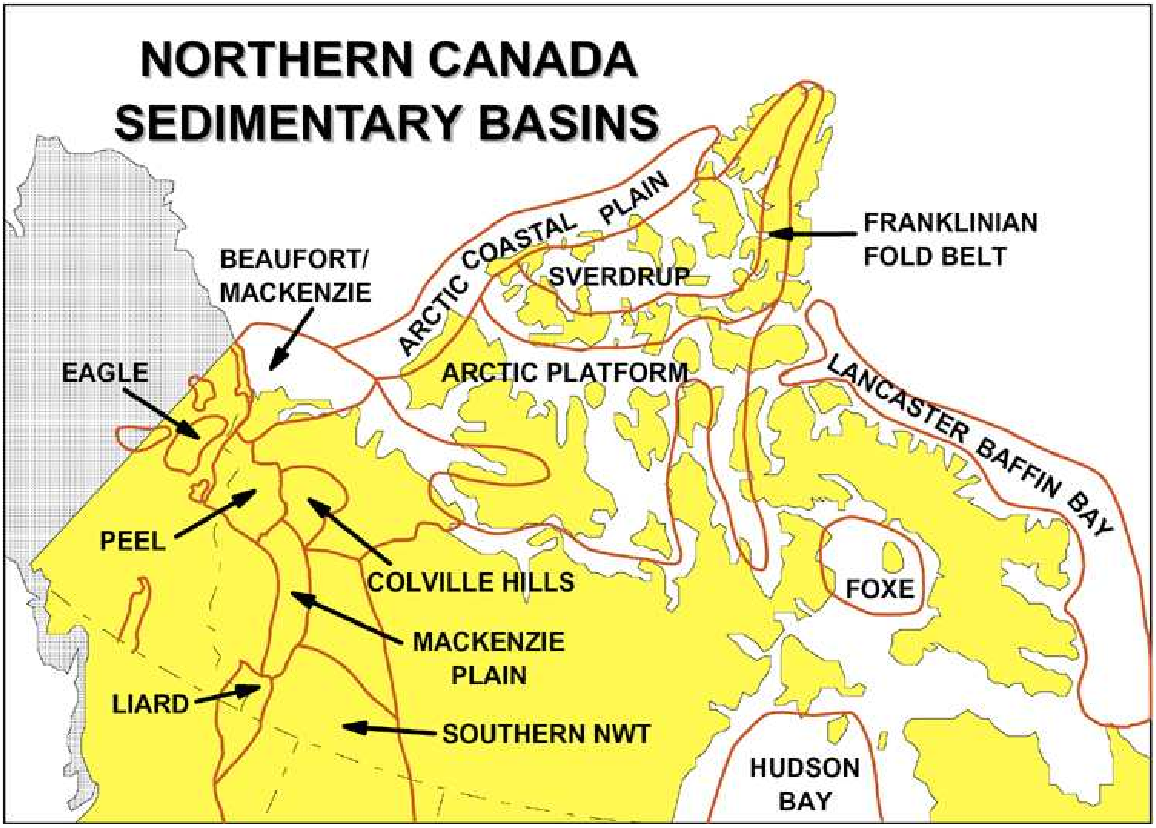
[138] K.J. Drummond, "Canada's Discovered Oil and Gas Resources North of 60" by Drummond Consulting. Posted April 10, 2006. http://www.searchanddiscovery.net/documents/2006/06022drummond/index.htm

**Figure 14.6**
**Locations of the Known Sedimentary Basins North of 60**




Source: K.J. Drummond, "Canada's Discovered Oil and Gas Resources North of 60
http://www.searchanddiscovery.net/documents/2006/06022drummond/index.htm

### 14.2.1 Northwest Territories

In 1920, the first well was drilled in the NWT located north of the Mackenzie River in a town called Norman Wells. Soon after, significant discoveries were made in the Beaufort/Mackenzie Basin, the Mackenzie Valley Corridor, and the Arctic Island. A publication by the government of NWT, released in 2007, reported that the area contains 12 billion barrels of potential oil reserves and 75 Tcf of natural gas reserves.[139] Table 14.2 illustrates NWT's oil resources.

[139] The Government of Northwest Territories, "Energy for the Future". Published in March 2007: http://www.iti.gov.nt.ca/Publications/2007/Energy/Energy%20for%20the%20Future.pdf

**Table 14.2**
**NWT Oil Resources**

| Location | Remaining Established Reserves (billion barrels) | Ultimate Recoverable Resources (billion barrels) |
|---|---|---|
| Mackenzie Delta/Beaufort | 1.01 | 6.7 |
| Arctic Islands | 0.41 | 4.7 |
| Mainland NWT | 0.08 | 0.6 |
| **Total** | **1.50** | **12.0** |

Source: "Energy for the Future", Government of Northwest Territories publication, page 11.

Currently, Imperial Oil Resources Ltd is the largest player in the NWT, producing from Norman Wells. Operating since 1943, the field will have a cumulative output of more than 39 million $m^3$ of oil by the end of 2007.[140] Other significant players include Anadarko Canada Corporation, Husky Oil Operations Ltd and Paramount Resources Ltd.

Natural gas production in the NWT totaled more than 980 million $m^3$ in 2003,[141] with the majority coming from Cameron Hills, Fort Liard, Norman Wells and Ikhil.[142] Table 14.3 shows NWT's natural gas resources, including produced resources and ultimate recoverable resources.

**Table 14.3**
**NWT Natural Gas Resources**

| Location | Produced Resources (billion cubic feet) | Ultimate Recoverable Resources (billion cubic feet) |
|---|---|---|
| Mackenzie Delta/Beaufort | | 60,000 |
| Ikhil | 3.5 | |
| Mackenzie Valley Corridor | | 5,000 |
| Cameron Hills | 16.7 | |
| Fort Liard | 156 | |
| Norman Wells | 137 | |
| Arctic Islands | | 10,000 |
| **Total** | **313.2** | **75,000** |

Source: "Energy for the Future", Government of Northwest Territories publication, page 11.

Due to the abundance of natural gas in the region, the Mackenzie Valley Pipeline project was proposed to supply Canadian and US markets with natural gas and NGLs from the Mackenzie Delta. The estimated $16.2 billion pipeline would connect three main natural gas fields: Niglintgak (1 Tcf), Toglu (3 Tcf) and Parsons Lake (1.8 Tcf). Three main fields, including neighbouring fields, together are estimated to supply 1.2 Bcf/d of natural gas over the life of the

140 CAPP, "Statistical Handbook", Page 93 Table 3.8a. Published March 2009: http://www.capp.ca/GetDoc.aspx?DocID=146286

141 Invest NWT, "Oil & Gas Industry Profile – An integrated approach to nurturing industry development and NWT wealth": http://www.investnwt.com/library/oilgas2005.pdf

142 The Government of Northwest Territories, "Energy for the Future". Published in March 2007: http://www.iti.gov.nt.ca/Publications/2007/Energy/Energy%20for%20the%20Future.pdf

project.[143] The project team consists of Imperial Oil (100 percent interest in Toglu), ConocoPhillips (75 percent Parsons Lake), ExxonMobil (25 percent Parsons Lake) and Shell Canada (100 percent Niglintgak). The project is expected to come online in 2014, if no delays occur.

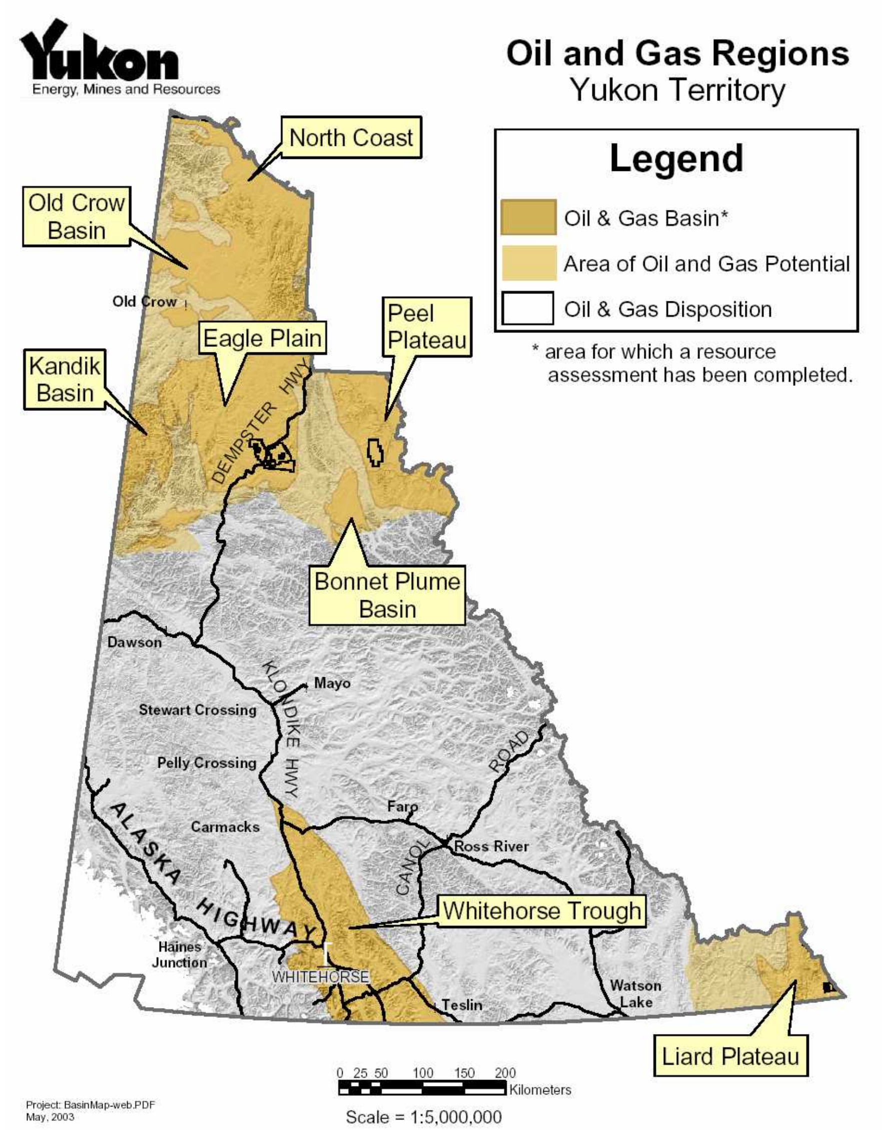
### 14.2.2 Yukon Territory

Currently, the Yukon Territory has eight sedimentary basins with potential oil and gas deposits. So far, approximately 73 wells have been drilled and both the NEB and the Geological Survey of Canada have incorporated geological field information to generate assessment studies of the territory.[144] The Figure 14.7 illustrates Yukon's sedimentary basins.

143 The Mackenzie Valley Pipeline Information Sheet: http://www.mackenziegasproject.com/moreInformation/publications/documents/Project_Overview.pdf

144 "Yukon Oil and Gas: A Northern Investment Opportunity" Published by the Government of Yukon, June 2008. Page 25: http://www.emr.gov.yk.ca/oilandgas/pdf/northern_investment2008.pdf

**Figure 14.7**
**Yukon's Eight Known Sedimentary Basins**




Source: : http://www.emr.gov.yk.ca/oilandgas/ra.html , Resource Assessment map

The aforementioned 73 wells are distributed predominantly in three different basins: Eagle Plain, Peel Plateau and Plain, and Liard. The number of wells to date in the three fields is 34, 19 and 13, respectively. The remaining wells to date are located in Kandik Basin (3), Beaufort–Mackenzie (3) and other (1). The latter is at Kotaneelee gas field.[145] The remaining five basins are still largely unexplored.

[145] Yukon Energy, Mines, and Resources. Exploration and Development section: http://www.emr.gov.yk.ca/oilandgas/exploration.html

The following table provides additional information regarding Yukon's onshore resource potential and combines natural gas and oil potential.

**Table 14.4**
**Yukon Onshore Resource Potential**

| Basin | Natural Gas (Bcf) | Oil (MMbls) |
|---|---|---|
| Beaufort – Mackenzie | 1008.1 | 216.7 |
| Old Crow | 1149.7 | 0 |
| Kandik | 648.9 | 99.3 |
| Eagle Plain | 6055.3 | 436.7 |
| Bonnet Plume | 800.4 | 0 |
| Peel Plateau and Plain | 2915.8 | 0 |
| Liard | 4109.9 | 0.1 |
| Whitehorse Trough | 423.4 | 19.2 |
| **Total** | **17,111.5** | **772.0** |

Source: "Yukon Oil and Gas: A Northern Investment Opportunity" Published by the Government of Yukon, June 2008. Page 25.

The Yukon government is encouraging more oil and gas activity in the region by investing in pipeline infrastructure. They are involved in the construction of the Mackenzie Valley Pipeline Project and the Alaska Highway Pipeline. The Yukon already has an existing pipeline, the Duke Energy Gas Transmission Pointed Mountain Pipeline. This pipeline supplies natural gas from the southern part of Yukon to the gas processing plant in Fort Nelson, British Columbia.[146]

### 14.2.3 Nunavut

Currently there is no oil and gas production in Nunavut, but the Government of Nunavut suggests that reserves in the Sverdrup Basin equals roughly 11 percent of Canada's crude oil and about 20 percent of the country's natural gas resources.[147] The potential is massive. Exploration and development in the region, however, will depend on several issues such as technological progress and resource ownership structure in the northern territory.

## 14.3 Northwest Territories: Economic Impacts

The following tables present the impacts associated with investment and operations, respectively, over a 25-year period. As it relates to investment and operation in Tables 14.5 and 14.6, 65 percent of the impacts are directly related to the Northwest Territories, with the remaining 35 percent being felt across the other provinces and territories.

[146] Invest Yukon: Yukon Economic Development – Oil & Gas. http://www.investyukon.com/index.php?option=com_content&task=blogcategory&id=22&Itemid=70

[147] Department of Economic Development and Transportation – Oil & Gas, Government of Nanuvut: http://www.edt.gov.nu.ca/lookupnunavut/oilgas.htm

**Table 14.5**
**Impacts Associated with Investment in the Northwest Territories**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 400 | 6 | 66 | 42 | 24 |
| **British Columbia** | 457 | 7 | 125 | 64 | 61 |
| **Manitoba** | 70 | 1 | 22 | 11 | 12 |
| **New Brunswick** | 20 | 0 | 7 | 3 | 3 |
| **Newfoundland & Labrador** | 15 | 0 | 5 | 2 | 3 |
| **Northwest Territories** | 9,071 | 104 | 2,297 | 1,537 | 760 |
| **Nova Scotia** | 35 | 1 | 12 | 6 | 7 |
| **Nunavut** | 104 | 2 | 53 | 40 | 12 |
| **Ontario** | 563 | 10 | 146 | 72 | 74 |
| **Prince Edward Island** | 4 | 0 | 2 | 1 | 1 |
| **Quebec** | 264 | 5 | 82 | 35 | 47 |
| **Saskatchewan** | 69 | 1 | 18 | 9 | 9 |
| **Yukon Territory** | 12 | 0 | 5 | 4 | 2 |
| **Canada** | 11,084 | 139 | 2,840 | 1,826 | 1,014 |

**Table 14.6**
**Impacts Associated with Operation in the Northwest Territories**

| | $ million | Thousand Person Years | $ million | | |
|---|---|---|---|---|---|
| | GDP | Employment | Total Net Tax | Federal | Provincial |
| **Alberta** | 1,353 | 19 | 224 | 143 | 81 |
| **British Columbia** | 1,146 | 19 | 313 | 161 | 152 |
| **Manitoba** | 392 | 8 | 125 | 60 | 65 |
| **New Brunswick** | 96 | 2 | 33 | 16 | 17 |
| **Newfoundland & Labrador** | 80 | 2 | 25 | 11 | 14 |
| **Northwest Territories** | 8,075 | 111 | 2,045 | 1,369 | 677 |
| **Nova Scotia** | 156 | 4 | 55 | 26 | 29 |
| **Nunavut** | 302 | 5 | 153 | 117 | 36 |
| **Ontario** | 2,448 | 44 | 634 | 311 | 323 |
| **Prince Edward Island** | 26 | 1 | 11 | 5 | 6 |
| **Quebec** | 899 | 18 | 279 | 120 | 158 |
| **Saskatchewan** | 409 | 7 | 108 | 53 | 55 |
| **Yukon Territory** | 17 | 0 | 8 | 5 | 2 |
| **Canada** | 15,399 | 240 | 4,013 | 2,398 | 1,616 |

The following three bar charts depict the total economic impacts as it relates to GDP, employment, and federal and provincial taxes, respectively, over a 25-year period. It is important to note that the charts reflect the impacts on the other provinces and territories, excluding the province in which the investment occurs. As it relates to GDP in Figure 14.8, Ontario receives 32 percent of the impacts, 19 percent for Alberta, 17 percent for British Columbia and 12 percent for Quebec. Figure 14.9 and Figure 14.10 show the similar impacts on employment, and federal and provincial taxes.

**Figure 14.8**
**Total GDP Impacts ($million)**

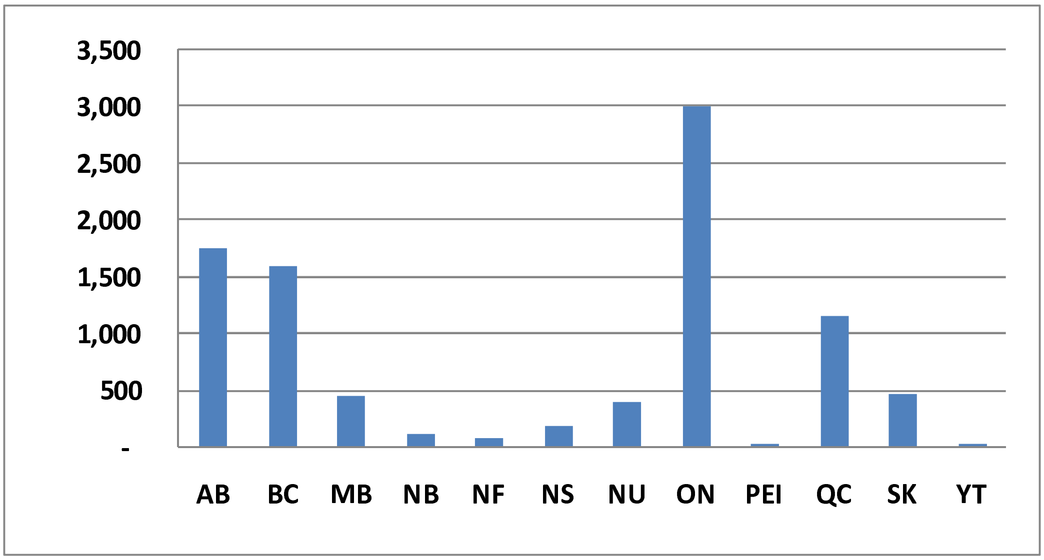



**Figure 14.9**
**Total Employment Impacts (thousand person years)**

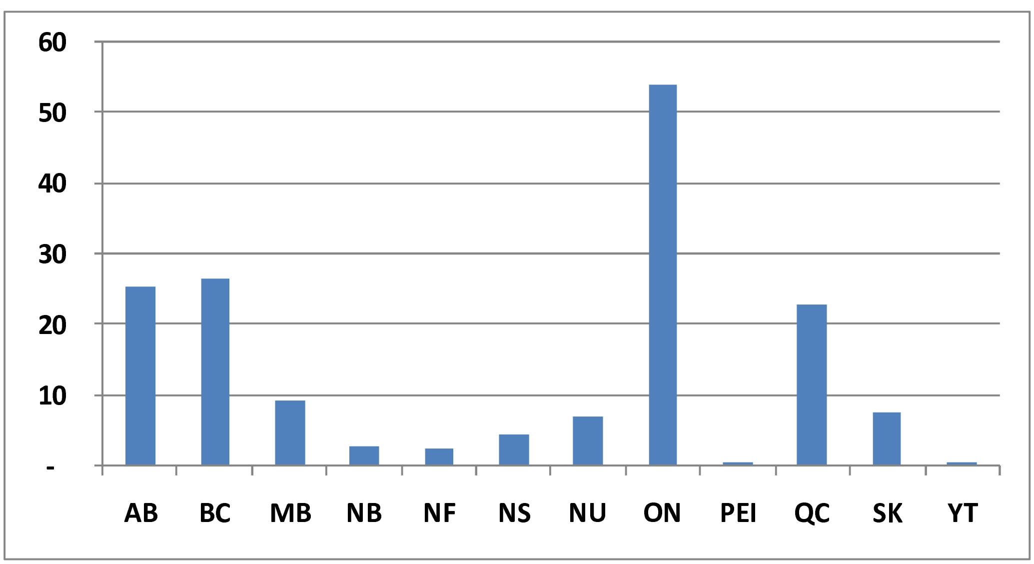
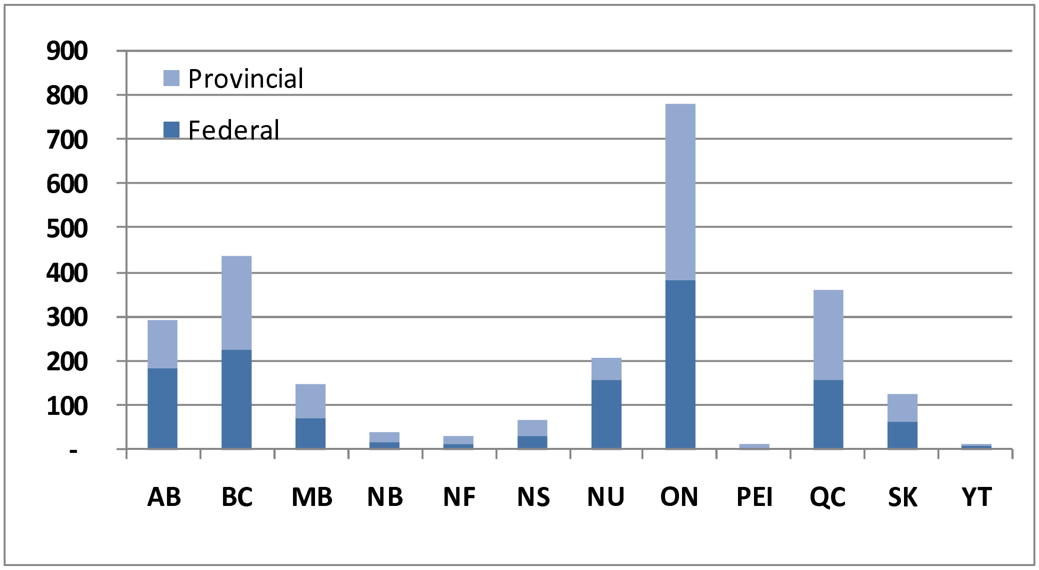


**Figure 14.10**
**Total Federal and Provincial Tax Impacts ($million)**




## 14.4 Yukon Territory: Economic Impacts

In spite of the Yukon Territories potential, as discussed in Section 14.2.2, it is not included in the scope of this project. This is due to the indeterminate time horizon of development.

## 14.5 Nunavut: Economic Impacts

Nunavut is not included in the scope of this project, due to the indeterminate time horizon of development. This is in spite of the huge Arctic Islands potential.

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# CHAPTER 15
# ECONOMIC IMPACTS: CANADA

This chapter discusses the total economic impacts for Canada. It is divided into four sections. The first section provides a background, describing reserves, production and expenditures of the petroleum industry in Canada. The second section discusses the economic impacts of the upstream oil and gas activities, while the third section reviews the economic impacts of other major capital projects. The final section presents the total economic impacts of the petroleum industry in Canada. In particular, impacts associated with investment and operations are presented, as well as total impacts regarding GDP, employment, federal and provincial taxes, and provincial royalties are discussed.

## 15.1 Background

### 15.1.1 Overview of Canada's Upstream Petroleum Industry

This study measures the incremental impacts of the development in the petroleum industry. It is, however, important to mention the value created by existing industry and activity. The following section provides a brief overview of Canada's upstream oil and natural gas industry. All figures contained within this section were taken from CAPP's Statistical Handbook for Canada's Upstream Petroleum Industry, published in March 2009. The following discusses drilling activity, remaining established reserves, production and expenditures/revenues.

<u>Drilling Activity, 2008</u>

- The total number of oil wells drilled in Canada was 4,991. Approximately 64 percent of the total oil wells drilled were development wells. Bitumen wells and exploratory wells accounted for 21 percent and 15 percent of the total oil wells drilled, respectively.

- Oil wells drilled totaled over 7.5 million metres.

- A total of 8,127 natural gas wells were drilled in Canada. Exploratory wells accounted for 9 percent of all natural gas wells drilled, the remainder of the wells were developmental.

- Natural gas wells drilled totaled 9.3 million metres.

- The number of abandoned or suspended exploratory oil and natural gas wells totaled 1,300.

- The number of abandoned or suspended oil and natural gas development wells totaled 1,765.

- Including stratigraphic test wells, service wells and miscellaneous wells, a total of 20,203 wells were drilled in Canada.

- Between 1955 and 2008, the cumulative number of wells drilled totaled 482,939, and the cumulative metres drilled totaled 547,455,461.

- Of the wells drilled between 1955 and 2008, 156,534 oil wells and 193,329 natural gas wells were completed. Attributable to Alberta was 52 percent of the oil, and 81 percent of the natural gas wells drilled and completed.

Remaining Established Reserves, December 31, 2007.

- Remaining established reserves of conventional crude oil and equivalents totaled 864,165 thousand $m^3$.

- Canada's remaining established reserves (in Alberta) of developed unconventional oil totaled 1,317,016 thousand $m^3$ for mining (upgraded oil and bitumen), and 786,590 thousand $m^3$ for in situ (bitumen).

- Canada's remaining established reserves of marketable natural gas was 1,633,824 million $m^3$ (57.7 Tcf), with 69 percent of the total located in Alberta.

Production

- Since 1947, Canada has produced 3,609,239,836 $m^3$ of crude oil. Western Canada accounted for 96 percent of total production.

- Cumulative production of synthetic crude and crude bitumen since 1967 totaled 832,776 thousand $m^3$.

- Between 1947 and 2007, a cumulative total of 5,843,175,102 thousand $m^3$ of raw natural gas was produced in Canada. Approximately 99 percent of the total was produced in western Canada. Marketed gas production totaled 4,646,587 million $m^3$.

- Over the past two decades, Canadian raw natural gas production increased by 99.2 percent to 203,483,830 thousand $m^3$ in 2007, while marketed natural gas production increased by 114 percent to 174,429 million $m^3$.

- In 2007, production of crude oil and equivalents averaged 439.4 thousand $m^3$ per day, increasing by 68.3 percent over the last two decades.

- Between 1987 and 2007, the average annual productive capacity of Canadian crude oil and equivalents, increased by 63.4 percent to 438 thousand $m^3$. The largest growing component was in situ bitumen, which increased by 344.4 percent to 80,000 $m^3$ in 2007. Over this period, the productive capacity of mined and upgraded crude oil, conventional light and heavy crude oil, and pentanes plus increased by 282.8 percent, 8.3 percent, and 52.9 percent, respectively.

- The number of oil wells operating in western Canada totaled 70,003 at the end of 2007.

- The number of oil and natural gas wells operating in western Canada totaled 70,003 and 128,614, respectively at the end of 2007.

Expenditures/Revenues

- Cumulative net cash expenditures of the Canadian petroleum industry, between 1947 and 2007, totaled $692,321 million.

- In 2007, net cash expenditures of the Canadian petroleum industry totaled $58,475.9 million. The majority of the expenditures (nearly 41 percent), were attributable to development costs, which includes the cost of drilling, field equipment, enhanced recovery and pressure maintenance, and natural gas plants. Exploration, operating, and royalty expenditures accounted for 13 percent, 25 percent, and 21 percent of total net cash expenditures, respectively.

- Net cash expenditures in Alberta's, Saskatchewan's, and British Columbia's petroleum industries accounted for 92.6 percent of the 2007 Canadian total, with $39,403 million, $6,459 million, and $8,261.2 million in net expenditures, respectively.

- Between 1958 and 2007, cumulative oil sands (in situ, mining, and upgraders) expenditures, consisting of capital, operating and royalty costs, totaled $170,245.8 million.

- In 2007, oil sands expenditures totaled $28,918.4 million, with in situ, mining, and upgrading accounting for 25.7 percent, 46.6 percent, and 27.7 percent of the total, respectively. The single largest component of total oil sands expenditures has consistently been the capital expenditures. In 2007, capital expenditures accounted for 62.5 percent of total oil sands expenditures.

- The value of Canada's crude oil and condensate sales in 2007 was $32,861,852 thousand, up $3,832,021 thousand, or 13.2 percent, from the previous year.

- The value of Canada's natural gas sales declined by $1,130,979 thousand, or 2.7 percent, from the previous year to 40,916,226 thousand in 2007.

## 15.2 Economic Impacts: Upstream Oil and Gas Activities

The total cost incurred by the industry in exploring and developing hydrocarbon resources is the sum of the drilling cost for the successful wells, as forecasted in the figures above, plus:

- the cost of wells that were not successful;
- the original cost of the mineral leases;
- the cost of the field gathering systems;
- the cost of field plant facilities (metering, plants, compression, pumps); and
- the costs for geological and geophysical systems.

In addition, the capital costs and operating conditions of the Alberta oil sands projects have been included in these totals.

Accounting for all these costs, the oil and gas companies will invest C$1.1 trillion (2008 dollars), which will result in incremental growth in gross domestic product (GDP) for the Canadian economy of C$3.5 trillion. The royalties payable to the province where the development takes place total C$429 billion, over the time frame of 25 years.

Table 15.1 illustrates total GDP impacts from upstream oil and gas activities. The columns show the GDP impacts in all provinces as a result of oil and gas industry investments made in the province indicated by the column title. The rows, on the other hand, show the GDP impacts for a given province (identified by the row title) as a result of oil and gas investments made in any province. For example, the second column illustrates all impacts directly related to oil and gas investment (in this case, all upstream oil and gas activities) in the province of British Columbia (conventional oil + conventional gas + shale/tight gas) and their impacts on the rest of the provinces and territories. In this case all oil and gas activities create a total GDP impact of C$3.5 billion in British Columbia, nearly C$12 billion in Alberta, C$11 billion in Ontario etc… Conversely, the second row reflects GDP impacts on British Columbia, as a result of investments made in the oil and gas industry in British Columbia and the other provinces. In other words, all upstream oil and gas activities in Alberta create an impact of C$92.8 billion on British Columbia, while oil and gas activities in Saskatchewan create a total GDP impact of C$7.6 billion on British Columbia. The *total GDP impacts on British Columbia* as a result of oil and gas activities across Canada totaled C$461 billion.

It is important to note that this table does not include major capital projects—these results are found in Section 2.3.

**Table 15.1**
**Total GDP Impacts: Upstream Oil & Gas Activities ($ million)**

| | AB | BC | MB | SK | Total |
|---|---|---|---|---|---|
| **AB** | 2,526,235 | 11,869 | 346 | 14,305 | 2,552,755 |
| **BC** | 92,787 | 361,135 | 271 | 7,557 | 461,750 |
| **MB** | 18,625 | 1,682 | 10,152 | 5,611 | 36,071 |
| **NB** | 3,619 | 538 | 27 | 374 | 4,559 |
| **NL** | 3,378 | 335 | 19 | 280 | 4,012 |
| **NT** | 2,640 | 209 | 6 | 204 | 3,059 |
| **NS** | 5,883 | 741 | 29 | 433 | 7,086 |
| **NU** | 569 | 50 | 2 | 34 | 655 |
| **ON** | 115,800 | 11,057 | 612 | 16,369 | 143,839 |
| **PE** | 733 | 106 | 5 | 64 | 908 |
| **QC** | 36,506 | 5,345 | 277 | 3,178 | 45,306 |
| **SK** | 44,225 | 2,276 | 173 | 198,305 | 244,979 |
| **YT** | 669 | 188 | 2 | 33 | 892 |
| **Total** | 2,851,670 | 395,532 | 11,920 | 246,747 | 3,505,869 |

As it relates to the individual provinces, the GDP impacts as a result of upstream oil and gas developments are shared as follows:

- Alberta 72.81%
- British Columbia 13.17%
- Manitoba 1.03%
- New Brunswick 0.13%
- Newfoundland & Labrador 0.11%
- Northwest Territories 0.09%
- Nova Scotia 0.20%
- Nunavut 0.02%
- Ontario 4.10%
- Prince Edward Island 0.03%
- Quebec 1.29%
- Saskatchewan 6.99%
- Yukon Territory 0.03%

### 15.3 Economic Impacts: Other Capital Projects

In addition to the impacts associated with upstream oil and gas activities there are several other capital projects that also contribute to the Canadian economy. The list of other capital projects is listed in this report by province. This study examines only representative projects and includes the following: the Enbridge Gateway pipeline project, the Kitimat LNG liquefaction project, the

Quebec LNG re-gasification terminal, the Mackenzie Valley pipeline project and the Nova Scotia's Deep Panuke offshore project.

Accounting for all these costs, the oil and gas companies will invest C$23.5 billion (2008 dollars), which will result in incremental growth in gross domestic product (GDP) for the Canadian economy of C$60 billion.

Table 15.2 illustrates total GDP impacts from upstream oil and gas activities.

**Table 15.2**
**Total GDP Impacts: Other Capital Projects ($ million)**

| | AB | BC | NT | NS | QC | Total |
|---|---|---|---|---|---|---|
| **AB** | 4,421 | 1,167 | 1,753 | 351 | 44 | 7,736 |
| **BC** | 306 | 14,944 | 1,603 | 255 | 45 | 17,153 |
| **MB** | 80 | 219 | 462 | 17 | 15 | 792 |
| **NB** | 15 | 61 | 115 | 69 | 20 | 280 |
| **NL** | 12 | 36 | 95 | 59 | 10 | 213 |
| **NT** | 10 | 21 | 17,146 | 111 | 1 | 17,289 |
| **NS** | 21 | 83 | 192 | 6,146 | 18 | 6,459 |
| **NU** | 3 | 7 | 406 | 2 | 1 | 419 |
| **ON** | 368 | 1,375 | 3,010 | 320 | 228 | 5,301 |
| **PE** | 3 | 12 | 30 | 32 | 3 | 80 |
| **QC** | 146 | 589 | 1,163 | 122 | 1,640 | 3,661 |
| **SK** | 121 | 252 | 478 | 37 | 12 | 900 |
| **YT** | 3 | 22 | 29 | 1 | 0 | 56 |
| **Total** | 5,508 | 18,786 | 26,483 | 7,522 | 2,038 | 60,337 |

The provincial share of GDP impacts are as follows:

- Alberta 12.82%
- British Columbia 28.43%
- Manitoba 1.31%
- New Brunswick 0.46%
- Newfoundland & Labrador 0.35%
- Northwest Territories 28.65%
- Nova Scotia 10.70%
- Nunavut 0.69%
- Ontario 8.79%
- Prince Edward Island 0.13%
- Quebec 6.07%
- Saskatchewan 1.49%
- Yukon Territory 0.09%

## 15.4 Economic Impacts: Canada

This section presents tables summarizing total economic impacts in Canada: total GDP impacts, total federal taxes, total provincial taxes, total employment impacts and total royalties (by province).

Table 15.3 presents total GDP Impacts. As previously indicated, the columns show the GDP impacts in all provinces as a result of oil and gas industry investments made in the province indicated by the column title. The rows, on the other hand, show the GDP impacts for a given province (identified by the row title) as a result of oil and gas investments made in any province.

Utilizing an example, the first column illustrates all impacts directly related to oil and gas investment in the province of Alberta (conventional oil + conventional gas + CBM + oil sands + capital projects) and their impacts on the rest of the provinces and territories. In this case all oil and gas activities in Alberta create a total GDP impact of C$2.5 trillion in Alberta, C$116 billion in Ontario, and C$93 billion in British Columbia. All oil and gas activities in Alberta have a total national impact of C$2.9 trillion. Conversely, the first row reflects GDP impacts on Alberta, as a result of investments made in the oil and gas industry in Alberta and the other provinces and territories. In other words, all upstream oil and gas activities in Saskatchewan create an impact of C$14 billion on Alberta, while oil and gas activities in British Columbia create a total GDP impact of C$13 billion on Alberta.

Total national GDP impacts from all investments analyzed by this study are $C3.6 trillion.

**Table 15.3**
**Total GDP Impacts ($C million)**

| | AB | BC | MB | NT | NS | QC | SK | Total |
|---|---|---|---|---|---|---|---|---|
| **AB** | 2,530,656 | 13,036 | 346 | 1,753 | 351 | 44 | 14,305 | 2,560,491 |
| **BC** | 93,093 | 376,078 | 271 | 1,603 | 255 | 45 | 7,557 | 478,903 |
| **MB** | 18,705 | 1,901 | 10,152 | 462 | 17 | 15 | 5,611 | 36,863 |
| **NB** | 3,634 | 599 | 27 | 115 | 69 | 20 | 374 | 4,839 |
| **NL** | 3,390 | 371 | 19 | 95 | 59 | 10 | 280 | 4,224 |
| **NT** | 2,650 | 230 | 6 | 17,146 | 111 | 1 | 204 | 20,348 |
| **NS** | 5,903 | 824 | 29 | 192 | 6,146 | 18 | 433 | 13,544 |
| **NU** | 572 | 57 | 2 | 406 | 2 | 1 | 34 | 1,073 |
| **ON** | 116,168 | 12,432 | 612 | 3,010 | 320 | 228 | 16,369 | 149,140 |
| **PE** | 736 | 118 | 5 | 30 | 32 | 3 | 64 | 987 |
| **QC** | 36,652 | 5,934 | 277 | 1,163 | 122 | 1,640 | 3,178 | 48,966 |
| **SK** | 44,346 | 2,528 | 173 | 478 | 37 | 12 | 198,305 | 245,879 |
| **YT** | 672 | 211 | 2 | 29 | 1 | 0 | 33 | 948 |
| **Total** | 2,857,178 | 414,318 | 11,920 | 26,483 | 7,522 | 2,038 | 246,747 | 3,566,206 |

The provincial share of GDP impacts are as follows:

- Alberta 71.80%
- British Columbia 13.43%
- Manitoba 1.03%
- New Brunswick 0.14%
- Newfoundland & Labrador 0.12%
- Northwest Territories 0.57%
- Nova Scotia 0.38%
- Nunavut 0.02%
- Ontario 4.18%
- Prince Edward Island 0.03%
- Quebec 1.37%
- Saskatchewan 6.89%
- Yukon Territory 0.03%

Table 15.4 presents the total federal tax impacts. The largest tax impact, on a federal basis, comes from Alberta's oil and gas activities. All oil and gas activities in Alberta have a total federal tax impact of C$311 billion, or nearly two-thirds of federal tax impacts. This is followed by British Columbia and Saskatchewan at C$58 and C$32 billion, respectively.

**Table 15.4**
**Total Federal Taxes ($C million)**

| | AB | BC | MB | NT | NS | QC | SK | Total |
|---|---|---|---|---|---|---|---|---|
| **AB** | 266,886 | 1,375 | 37 | 185 | 37 | 5 | 1,509 | 270,033 |
| **BC** | 13,101 | 52,924 | 38 | 226 | 36 | 6 | 1,063 | 67,394 |
| **MB** | 2,848 | 290 | 1,546 | 70 | 3 | 2 | 854 | 5,613 |
| **NB** | 625 | 103 | 5 | 20 | 12 | 3 | 64 | 832 |
| **NL** | 450 | 49 | 2 | 13 | 8 | 1 | 37 | 561 |
| **NT** | 449 | 39 | 1 | 2,906 | 19 | 0 | 35 | 3,449 |
| **NS** | 977 | 136 | 5 | 32 | 1,018 | 3 | 72 | 2,243 |
| **NU** | 222 | 22 | 1 | 158 | 1 | 0 | 13 | 417 |
| **ON** | 14,768 | 1,580 | 78 | 383 | 41 | 29 | 2,081 | 18,960 |
| **PE** | 143 | 23 | 1 | 6 | 6 | 1 | 12 | 192 |
| **QC** | 4,900 | 793 | 37 | 155 | 16 | 219 | 425 | 6,546 |
| **SK** | 5,785 | 330 | 23 | 62 | 5 | 2 | 25,870 | 32,076 |
| **YT** | 208 | 65 | 1 | 9 | 0 | 0 | 10 | 293 |
| **Total** | 311,364 | 57,730 | 1,773 | 4,224 | 1,201 | 272 | 32,046 | 408,609 |

The provincial share of federal tax impacts are as follows:

- Alberta 66.09%
- British Columbia 16.50%
- Manitoba 1.37%
- New Brunswick 0.20%
- Newfoundland & Labrador 0.14%
- Northwest Territories 0.84%
- Nova Scotia 0.55%
- Nunavut 0.10%
- Ontario 4.64%
- Prince Edward Island 0.05%
- Quebec 1.60%
- Saskatchewan 7.85%
- Yukon Territory 0.07%

Table 15.5 illustrates total provincial taxes. The largest tax impact, on a provincial basis, also comes from Alberta's oil and gas activities. All oil and gas activities in Alberta have a total provincial tax impact of C$189 billion, or nearly 55 percent of all provincial tax impacts. This is followed by British Columbia and Saskatchewan at C$54 and C$33 billion, respectively.

**Table 15.5**
**Total Provincial Taxes ($C million)**

| | AB | BC | MB | NT | NS | QC | SK | Total |
|---|---|---|---|---|---|---|---|---|
| **AB** | 152,257 | 784 | 21 | 105 | 21 | 3 | 861 | 154,052 |
| **BC** | 12,358 | 49,924 | 36 | 213 | 34 | 6 | 1,003 | 63,574 |
| **MB** | 3,119 | 317 | 1,693 | 77 | 3 | 2 | 936 | 6,147 |
| **NB** | 633 | 104 | 5 | 20 | 12 | 3 | 65 | 843 |
| **NL** | 598 | 65 | 3 | 17 | 10 | 2 | 49 | 745 |
| **NT** | 222 | 19 | 0 | 1,437 | 9 | 0 | 17 | 1,705 |
| **NS** | 1,109 | 155 | 5 | 36 | 1,154 | 3 | 81 | 2,544 |
| **NU** | 68 | 7 | 0 | 48 | 0 | 0 | 4 | 127 |
| **ON** | 15,317 | 1,639 | 81 | 397 | 42 | 30 | 2,158 | 19,665 |
| **PE** | 155 | 25 | 1 | 6 | 7 | 1 | 13 | 208 |
| **QC** | 6,459 | 1,046 | 49 | 205 | 22 | 289 | 560 | 8,629 |
| **SK** | 5,986 | 341 | 23 | 64 | 5 | 2 | 26,767 | 33,188 |
| **YT** | 94 | 30 | 0 | 4 | 0 | 0 | 5 | 133 |
| **Total** | 189,226 | 54,457 | 1,918 | 2,630 | 1,320 | 341 | 32,519 | 282,411 |

The provincial share of provincial tax impacts are as follows:

- Alberta 54.55%
- British Columbia 22.51%
- Manitoba 2.18%
- New Brunswick 0.30%
- Newfoundland & Labrador 0.26%
- Northwest Territories 0.60%
- Nova Scotia 0.90%
- Nunavut 0.04%
- Ontario 6.96%
- Prince Edward Island 0.07%
- Quebec 3.06%
- Saskatchewan 11.75%
- Yukon Territory 0.05%

Table 15.6 presents total employment impacts in thousand person years. Total employment reflects the incremental employment, as a result of the investments in the upstream and other capital projects, analyzed by this study. It includes direct employment due to construction and operation of the assets, indirect employment and induced employment in the support and manufacturing industries.

**Table 15.6**
**Total Employment (thousand person years)**

| | AB | BC | MB | NT | NS | QC | SK | Total |
|---|---|---|---|---|---|---|---|---|
| **AB** | 13,750 | 166 | 4 | 25 | 2 | 1 | 117 | 14,065 |
| **BC** | 1,265 | 2,778 | 4 | 27 | 2 | 1 | 90 | 4,166 |
| **MB** | 342 | 35 | 106 | 9 | 0 | 0 | 81 | 574 |
| **NB** | 71 | 12 | 1 | 3 | 2 | 0 | 8 | 95 |
| **NL** | 69 | 7 | 0 | 2 | 1 | 0 | 5 | 85 |
| **NT** | 26 | 3 | 0 | 215 | 0 | 0 | 1 | 245 |
| **NS** | 106 | 16 | 1 | 4 | 45 | 0 | 8 | 180 |
| **NU** | 10 | 1 | 0 | 7 | 0 | 0 | 1 | 19 |
| **ON** | 1,689 | 196 | 10 | 54 | 5 | 4 | 236 | 2,193 |
| **PE** | 15 | 2 | 0 | 1 | 1 | 0 | 1 | 21 |
| **QC** | 600 | 99 | 4 | 23 | 2 | 30 | 54 | 812 |
| **SK** | 579 | 41 | 3 | 8 | 0 | 0 | 1,421 | 2,052 |
| **YT** | 9 | 3 | 0 | 0 | 0 | 0 | 0 | 13 |
| **Total** | 18,530 | 3,359 | 132 | 379 | 60 | 36 | 2,024 | 24,522 |

As an example, investments in the province of Alberta will generate incremental employment of 13,750 thousand person years, within the province, and generates an additional 4,780 thousand person years across the country (reaching a total of 18,530 thousand person years).

In total, the oil and gas industry contributes 24,522 thousand person years in Canada.

Table 15.7 presents total provincial royalties, both total and annual. The royalties payable to the province where the development takes place total C$429 over the time frame of 25-years, or approximately C$17 billion per year.

**Table 15.7**
**Provincial Royalties: Total and Annual ($ million)**

| | $ million | |
|---|---|---|
| | **Royalties** | **Royalties/year** |
| **Alberta Total** | 295,194 | 11,808 |
| **British Columbia Total** | 89,730 | 3,589 |
| **Saskatchewan Total** | 43,471 | 1,739 |
| **Manitoba Total** | 543 | 22 |

Contribution from the various resource types to this table (i.e. Alberta oil sands) can be obtained in the main report under the appropriate province and resource type.

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