OVERVIEW OF EASTERN AND ATLANTIC CANADA’S PETROLEUM INDUSTRY AND ECONOMIC IMPACTS OF OFFSHORE ATLANTIC PROJECTS (2010-2035)
Overview of Eastern and Atlantic Canada’s Petroleum Industry and Economic Impacts of Offshore Atlantic Projects (2010-2035)

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# List of Abbreviations and Acronyms

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>Bb</td>
<td>Billions of barrels</td>
</tr>
<tr>
<td>Bcf</td>
<td>Billions of cubic feet</td>
</tr>
<tr>
<td>BNA</td>
<td>Ben Nevis/Avalon</td>
</tr>
<tr>
<td>CAPP</td>
<td>Canadian Association of Petroleum Producers</td>
</tr>
<tr>
<td>CBM</td>
<td>Coalbed Methane</td>
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<tr>
<td>CERI</td>
<td>Canadian Energy Research Institute</td>
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<tr>
<td>CF</td>
<td>Cash Flow</td>
</tr>
<tr>
<td>CFB</td>
<td>Call for Bids</td>
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<tr>
<td>CHHC</td>
<td>Canada Hibernia Holding Company</td>
</tr>
<tr>
<td>CNLOPB</td>
<td>Canada-Newfoundland and Labrador Offshore Petroleum Board</td>
</tr>
<tr>
<td>CNSOPB</td>
<td>Canada-Nova Scotia Offshore Petroleum Board</td>
</tr>
<tr>
<td>CPI</td>
<td>Consumer Price Index</td>
</tr>
<tr>
<td>DPA</td>
<td>Development Plan Application</td>
</tr>
<tr>
<td>E&amp;D</td>
<td>Exploration and Development</td>
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<tr>
<td>EL</td>
<td>Exploration License</td>
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<tr>
<td>FEED</td>
<td>Front End Engineering Design</td>
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<tr>
<td>FPSO</td>
<td>Floating, Production, Storage, and Offloading</td>
</tr>
<tr>
<td>GBS</td>
<td>Gravity Based Structure</td>
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<tr>
<td>GDP</td>
<td>Gross Domestic Product</td>
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<tr>
<td>HH</td>
<td>Henry Hub</td>
</tr>
<tr>
<td>HSE</td>
<td>Hibernia South Extension</td>
</tr>
<tr>
<td>HVAC</td>
<td>Heating, Ventilation, and Air Conditioning</td>
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<tr>
<td>I/O</td>
<td>Input/Output</td>
</tr>
<tr>
<td>LPGs</td>
<td>Liquefied Petroleum Gases</td>
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<tr>
<td>LTBR</td>
<td>Long-Term Bond Rate</td>
</tr>
<tr>
<td>M&amp;NP</td>
<td>Maritimes and Northeast Pipeline</td>
</tr>
<tr>
<td>Mb/d</td>
<td>Thousands of barrels per day</td>
</tr>
<tr>
<td>Mcf/d</td>
<td>Thousands of cubic feet per day</td>
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<tr>
<td>MMb</td>
<td>Millions of barrels</td>
</tr>
<tr>
<td>MMcf/d</td>
<td>Millions of cubic feet per day</td>
</tr>
<tr>
<td>MODU</td>
<td>Mobile Offshore Drilling Unit</td>
</tr>
<tr>
<td>MOPU</td>
<td>Mobile Offshore Production Unit</td>
</tr>
<tr>
<td>NB</td>
<td>New Brunswick</td>
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<tr>
<td>NEB</td>
<td>National Energy Board</td>
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*November 2011*
NGLs  Natural Gas Liquids
NL   Newfoundland and Labrador
NS   Nova Scotia
NTT  Newfoundland Transhipment Terminal
OLS  Offshore Loading System
PADD Petroleum Administration for Defense Districts
PCS  Potash Corporation of Saskatchewan
PEI  Prince Edward Island
PFA  Play Fairway Analysis
PFC  Production Field Centre
PL   Production License
RPPs Refined Petroleum Products
SDL  Significant Discovery License
SEA  Strategic Environmental Assessment
SOEP Sable Offshore Energy Project
SWR  South White Rose
Tcf  Trillions of cubic feet
UCMRIO United States-Canada Multi-Regional Input/Output
US   United States
WCSB Western Canada Sedimentary Basin
WHGBS Wellhead Gravity Based Structure
WTI  West Texas Intermediate
WWR  West White Rose
XR   Exchange Rate
Executive Summary and Highlights

As resources are delineated and exploration companies have been more actively involved in the region, Eastern Canada\(^1\) has the potential to become a region of increasing importance in terms of future resource development for the Canadian petroleum industry (mainly, Quebec and possibly Ontario).

However public opposition and regulator’s initiatives have created a cloud of uncertainty around future resource development in some regions.

Nonetheless, Eastern Canada has a history of hydrocarbon development, yet the produced volumes coming from the region are not very significant on a national scale.

However, Eastern Canada’s main driver of activity for the Canadian oil and gas industry lies on the demand side, as well as a source of inputs (human and physical capital) for the petroleum industry.

Eastern Canada’s economic structure and importance also means that this region is a significant recipient of the economic benefits associated with oil and gas developments across Canada.

Recently, companies have sought to transfer knowledge and technology from other regions in North America and moved to explore potential conventional and unconventional hydrocarbon resources including coalbed methane (CBM), shale gas, and shale oil, onshore, across the Atlantic Provinces of New Brunswick, Prince Edward Island, Nova Scotia, and Newfoundland and Labrador.

This trend is, however, fairly recent, the number of commercial developments are scarce, and thus there is a high degree of uncertainty in regards to how future petroleum development in these areas will unfold.

Atlantic Canada\(^2\) is home to an important segment of Canada’s petroleum industry. Natural gas development offshore shallow water Nova Scotia and crude oil development off Newfoundland and Labrador’s offshore areas have increasingly become more important over the last couple of decades in the overall Canadian context.

The industry has sought to explore for and develop petroleum resources around the various offshore areas, while the local economy (including governments, businesses, and the general public) has benefited from such development.

---

\(^1\) In the context of this report, Eastern Canada refers to the provinces of Ontario and Quebec

\(^2\) In the context of this report, Atlantic Canada refers to the provinces of New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland and Labrador
Meanwhile, various projects have advanced and continue to produce resources as planned, while new projects are being built as companies move from the drawing board and exploration phases to the development and operation stages.

This region (the offshore) will continue to be the focus of hydrocarbon development in the eastern half of Canada over the medium to long term,\(^3\) and it is thus the focus of our analysis.

The offshore projects included in our analysis are currently operating projects in Nova Scotia (such as the Sable Offshore Energy Project [SOEP]) as well as those in Newfoundland and Labrador (Hibernia, Terra Nova, and White Rose).

Also, projects which are expected to be developed over the next decade, with a high degree of certainty, including the Deep Panuke sour gas project, and the Hebron heavy crude oil project, are included in our analysis.

In order to be able to generate an outlook for production and capital expenditures, two models were developed by the Canadian Energy Research Institute (CERI) for analyzing offshore Atlantic projects.

One model is the unconstrained production outlook model which was developed on a project-by-project basis, and takes into consideration historical production patterns, resource constraints, and project design limitations.

The second model is a cash-flow (CF) outlook model (also developed on a project-by-project basis) that includes all the information necessary to evaluate a project’s economics, and in turn provides a feedback mechanism that constraints a project’s production outlook as needed.

The results from these models (oil and gas production volumes, as well as industry expenditures), as presented in Figures E.1 and E.2, are used as inputs or injections into CERI’s United States-Canada Multi-Regional Input/Output Model (UCMRO 2.0)

This model in turn estimates the economic impacts associated with the level of activity stemming from the outlook models over the 2010 to 2035 time period.

Thus, the obtained results are the estimated economic benefits stemming from the offshore industry’s continued activity offshore Atlantic Canada over the outlook period (2010-2035) including:

\(^3\) In the context of this report the terms short, medium, and long term are defined as five, ten, and over ten year periods in the outlook, correspondingly. This is the case as the reference outlook period is 25 years.
Figure E.1: Offshore Nova Scotia Natural Gas Historical (1999-2009) and Outlook (2010-2035) Production (MMcf/d), by Project (top) & Offshore Nova Scotia Projects Historical (1994-2009) and Outlook (2010-2035) Expenditures (Millions of $ 2010), 4 by Project (bottom)

Note: See notes for Figures 2.6 and 2.10 on main report.

Source: CAPP data, CNSOPB data, EnCana data, ExxonMobil Sable Project data, NEB data, Stantec/Nova Scotia Department of Energy study data, outlook analysis and figure by CERI.

4 Unless otherwise stated, all values are given in 2010 real (inflation-adjusted) Canadian dollars and Unites States (US)/Canadian Dollar parity is assumed
Figure E.2: Offshore Newfoundland and Labrador Crude Oil Historical (1997-2009) and Outlook (2010-2035) Production (Mb/d), by Project (top) & Offshore Newfoundland and Labrador Projects Historical (1990-2009) and Outlook (2010-2035) Expenditures (Millions of $ 2010), by Project (bottom)

Note: See notes for Figure 2.12 on main report.

Sources: CAPP data, CNLOPB data, Memorial University data, NEB Data, outlook analysis and figure by CERI.
Economic Impacts of Offshore Nova Scotia Projects

In Canada

- Close to $4 billion in industry investments (including capital and operating expenditures) generated offshore Nova Scotia (NS) over the outlook period\(^5\)
- Over 1 trillion cubic feet (1 tcf) of cumulative natural gas production over the outlook period
- Over $5 billion in value added gross domestic product (GDP) across Canada over the outlook period
- Over $1 billion in employment compensation (including wages and benefits) across Canada over the outlook period
- Direct employment in NS stemming from the local offshore industry, calculated at over 600 jobs at the start of the outlook period, will reach a peak of close to 1,000 jobs by 2011, from which point will exhibit an overall declining pattern until 2025
- A total of over 5,600 direct jobs created and preserved in NS over the outlook period
- Total employment in Canada (including direct, indirect, and induced) stemming from NS’s offshore industry, calculated at over 2,700 jobs at the start of the outlook period, will reach a peak of close to 4,000 jobs by 2011, from which point will exhibit an overall declining pattern until 2025
- A total of over 25,000 jobs created and preserved across Canada (direct, indirect, and induced) over the outlook period
- Over $1 billion in tax receipts (including indirect, personal, and corporate taxes) to all levels of government (municipal, provincial, and federal) in Canada over the outlook period
- In Canada, the largest share of the economic benefits are allocated to Nova Scotia, followed by Ontario, Quebec, and the rest of Canada
- Over $700 million in royalties to the NS government over the outlook period

In the United States

- Over $330 million in value added GDP across the United States (US) over the outlook period, with PADD I (East Coast, closest market and location of existing associated transportation infrastructure), PADD II (Midwest, large refining and petrochemical cluster), and PADD V (West Coast, large economy and demand centre), in that order, receiving the greatest share of such benefits
- Over $167 million in employment compensation across the US over the outlook period

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\(^5\) While the general reference outlook period for this study is from 2010 to 2035, based on current (as of the time of writing) project’s available information and CERI’s models results, no offshore natural gas production is expected in Nova Scotia past 2025. Therefore, the economic benefits associated with offshore natural gas development in Nova Scotia are expected to occur in the 2010 to 2025 time period and are limited to those associated with the SOEP and Deep Panuke projects. This is outlook is, however, based on CERI’s assumptions and subject to both upside and downside risks as discussed in Chapter 3 of this report.
• Employment in the US (indirect and induced) stemming from NS’s offshore industry, calculated at over 400 jobs at the start of the outlook period, will reach a peak of over 600 jobs by 2011, from which point will exhibit an overall declining pattern until 2025
• A total of over 4,000 jobs created and preserved across the US over the outlook period
• In the US, the states of Massachusetts, California, Texas, New York, and New Hampshire (in that order), are expected to benefit the most from the economic impacts of Nova Scotia’s offshore industry

Economic Impacts of Offshore Newfoundland and Labrador Projects

In Canada

• Over $35 billion in industry investments (including capital and operating expenditures) generated offshore Newfoundland and Labrador (NL) over the outlook period
• Over 1.7 billion barrels (Bb) of cumulative crude oil production over the outlook period
• Over $193 billion in value added gross domestic product (GDP) across Canada over the outlook period
• Close to $20 billion in employment compensation across Canada over the outlook period
• Direct employment in NL stemming from the local offshore industry, calculated at close to 5,000 jobs at the start of the outlook period, will reach a peak of close to 6,000 jobs by 2020, from which point will exhibit an overall declining pattern reaching an estimated level of about 1,000 jobs by 2035
• A total of over 104,000 direct jobs created and preserved in NL over the outlook period
• Total employment in Canada (including direct, indirect, and induced) stemming from NL’s offshore industry, calculated at about 17,000 jobs at the start of the outlook period, will reach a peak of close to 23,000 jobs by 2020, from which point will exhibit an overall declining pattern reaching an estimated level of over 5,000 jobs by 2035
• A total of over 420,000 jobs created and preserved across Canada (direct, indirect, and induced) over the outlook period
• Close to $36 billion in tax receipts (including indirect, personal, and corporate taxes) to all levels of government (municipal, provincial, and federal) in Canada over the outlook period
• In Canada, the largest share of the economic benefits are allocated to Newfoundland and Labrador, followed by Ontario, Quebec, and the rest of Canada
• $46 billion in royalties to the NL government over the outlook period

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6 While CERI’s models estimate offshore crude oil production from Newfoundland and Labrador (based on existing projects plus the Hebron project) to continue until 2046, the general reference outlook period for this report is 2010 to 2035, as previously stated. As in the case for Nova Scotia, the outlook is however, based on CERI’s assumptions and subject to both upside and downside risks as discussed in Chapter 4 of this report
In the United States

- Over $8 billion in value added GDP across the United States (US) over the outlook period, with PADDs I, II, and V (in that order) receiving the greatest share of such benefits
- Over $4 billion in employment compensation across the US over the outlook period
- Employment in the United States (indirect and induced) stemming from NL’s offshore industry, calculated at over 4,000 jobs at the start of the outlook period, will reach a peak of close to 6,000 jobs by 2011, from which point will exhibit an overall declining pattern reaching an estimated level of over 1,000 jobs by 2035
- A total of over 102,000 jobs created and preserved across the United States over the outlook period
- In the US, the states of New York, Maine, California, Texas, and Florida (in that order), are expected to benefit the most from the economic impacts of Newfoundland and Labrador’s offshore industry

Clearly, there are several and significant economic benefits associated with the continued and expected future development of the offshore petroleum industry in Atlantic Canada. However, it is important to note that these benefits are associated with CERI’s unique assumptions and outlook for future development in the region, and as such, the results are subject to both upside and downside risks over the long term as discussed in this report.
Introduction and Report Structure

Various regions in Eastern and Atlantic Canada are of major importance to the petroleum industry due to their large populations (demand) and their industrial sectors’ relation to the industry across Canada as a source of inputs (mainly Ontario and Quebec).

Meanwhile, other provinces have recently started to explore for and are sought to possibly develop onshore conventional and unconventional oil and natural gas resources over the medium to long term (including Quebec, New Brunswick, Prince Edward Island, Newfoundland and Labrador, and Nova Scotia).

Yet, only offshore oil and gas projects (in Nova Scotia and Newfoundland and Labrador) have significantly contributed to Canadian hydrocarbon production levels over the last few decades. These projects have not only generated investments by the oil and gas industry in the region, but also spawned a host of economic benefits to various stakeholders at various levels across North America\(^1\) over the same time period.

The high degree of uncertainty associated with development of petroleum resources in not-yet-developed regions where resources are not clearly delineated and commercial projects are not yet present or in operation, makes it a difficult task (if not possible but with a high degree of uncertainty and speculation) to establish a reasonable outlook or forecast for future development.

For this reason, only established regions with already developed commercial projects and where future project plans are underway are examined in this report. These include: offshore shallow water natural gas projects in Nova Scotia, as well as offshore crude oil projects in Newfoundland and Labrador (offshore Atlantic Projects).

This report begins with an overview of the petroleum industry in Eastern and Atlantic Canada (Chapter 1), followed by an explanation of the methodology developed by the Canadian Energy Research Institute (CERI) to establish an outlook for production as well as a discussion of the cash-flow (CF) models developed for the allocation of historical and future capital and operating expenditures (investments) for offshore oil and gas projects in Atlantic Canada (Chapter 2). These chapters together will be the components of the first part of this report.

The second part of this report will discuss the results obtained from CERI’s Input/Output (I/O) model, in regards to development of offshore projects off Nova Scotia and Newfoundland and Labrador. CERI’s Input/Output model estimates various levels of economic impacts across Canada and the United States (US), ranging from value added gross domestic product (GDP) impacts, to employment (job creation and preservation) impacts, employment compensation (including wages and supplements), as well as taxation revenues across all levels of

\(^1\)In the context of this report, North America refers to Canada and the United States
government. CERI’s production and cash-flow models are used to calculate future royalty revenues for the respective provincial governments.

Chapter 3 will present the obtained results (economic impacts) from continued operation of existing natural gas projects and investment on projects currently under development in offshore shallow water Nova Scotia, while Chapter 4 will serve the same purpose as Chapter 3 but in regards to offshore crude oil projects in Newfoundland and Labrador.
Chapter 1 – Overview of Eastern and Atlantic Canada’s Petroleum Industry

Eastern Canada’s Petroleum Industry
As resources are delineated and exploration companies have been more actively involved in the region, Eastern Canada has the potential to become a region of increasing importance in terms of future resource development for the Canadian petroleum industry (mainly, Quebec and possibly Ontario). However, public opposition and regulator’s initiatives have created a cloud of uncertainty around future resource development in some regions.

Nonetheless, Eastern Canada has a history of hydrocarbon development, yet the produced volumes coming from the region are not very significant on a national scale. However, Eastern Canada’s main driver of activity for the Canadian oil and gas industry lies on the demand side, as well as a source of inputs (human and physical capital) for the petroleum industry.

Eastern Canada’s economic structure and importance also means that this region is a significant recipient of the economic benefits associated with oil and gas developments across Canada.

Ontario
Ontario is one of the birthplaces for the Canadian oil and gas industry, Canada’s second natural gas field was discovered in south-western Ontario in 1866, and the area was one of the most important places for natural gas development until the early 1900s.¹

Over the last few decades natural gas development has continued in Ontario, yet Ontario’s raw natural gas production of 23 million cubic feet per day (MMcf/d) in 2009 only accounted for less than 0.1 percent of Canada’s total (17,653 MMcf/d).²

In terms of crude oil production, Ontario was home to the first commercial oil well dug in North America (1858) by James Miller Williams (founder of North America’s first fully integrated oil company, Williams). Yet, crude oil production in Ontario in 2009 was about 1.6 thousand barrels per day (Mb/d), accounting for 0.1 percent of Canada’s 1,217 Mb/d conventional crude oil production levels in the same year.³

While Ontario’s oil and gas production is not very significant compared to other provinces (mainly those located in the Western Canada Sedimentary Basin [WCSB]), Ontario is important to the petroleum industry for various other reasons.

Over the last few years there has been an interest in regions of south-eastern Ontario which are believed to hold considerable potential for significant shale resources. These regions include the Blue Mountain/Collingwood regions, which are located at the crossroads of Quebec’s Utica shale (see Quebec’s section) and Michigan’s Collingwood shale, two regions where there has been an increased level of industry activity; as well as a Marcellus extension from the north-eastern United States (US) region, and the Kettle point region. While these regions might hold considerable potential, it is too early to tell what the industry development path would be in the area, until commercial scale projects are developed.

Ontario’s population of 13.3 million accounts for close to 39 percent of Canada’s total (34.3 million), thus making Ontario a significant market for natural gas, crude oil, and refined petroleum products (RPPs).

Ontario’s natural gas needs for heating, industrial use, and electricity generation are mainly met through pipeline shipments from the west (British Columbia, Alberta, and Saskatchewan), while Ontario is also home to a large petrochemical and refinery cluster which in turn represents high demand levels for natural gas liquids (NGLs), liquefied petroleum gases (LPGs), and crude oil.

Further, Ontario’s large manufacturing, financial, and services sectors (Ontario’s largest industry sectors) contribute to the physical and capital development of the petroleum industry in Canada (including the oil sands and offshore petroleum industries), thus making Ontario a recipient of a large share of the economic benefits associated with industry development across Canada.

While Ontario’s importance to the Canadian petroleum industry is significant (demand and inputs), the future development of oil and gas resources (production) in the province over the medium- to long-term is not expected to change dramatically. Ontario is expected to remain a

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Overview of Eastern and Atlantic Canada’s Petroleum Industry and Economic Impacts of Offshore Atlantic Projects (2010-2035)

minor player in the supply side and thus Ontario’s future hydrocarbon production is not analysed in this report.

Quebec

Quebec’s history of petroleum exploration goes back to the 1800s as oil seeps were discovered in the sedimentary outcrops of the Saint Lawrence lowlands. At the time however, the resources were not economically recoverable. Starting in the late 1960s and early 1970s, production of raw natural gas from Quebec reached peak levels of about 0.54 MMcf/d (540 Mcf/d) by 1973. Production of natural gas was shut-in during the late 1970s and similar to peak production levels were reached in the early 1980s.

Production once again was shut-in in the early 1980s, yet during the late 1980s/early 1990s production of raw natural gas was constant at about 0.23 MMcf/d. Since those days, production has been insignificant or non existent.

Figure 1.1: Natural Gas Production (MMcf/d) (Right Scale) and Petroleum Industry Expenditures in Quebec (Millions of $ 2010) (Left Scale), 1971-2009

Source: CAPP data, figure by CERI.

9Unless otherwise specified, all $ values in this report are given in 2010 real Canadian dollars
As shown in Figure 1.1, production levels have historically moved in tandem with industry investment levels. One trend that is apparent from this figure is that since most of the investment\textsuperscript{11} was allocated to exploration activities over the last few decades,\textsuperscript{12} observed production levels are mainly related to exploration activities.

Over the last decade (2000s) not only have overall investment levels increased exponentially (a total of $230 million between 2000 and 2009) driven by exploration expenditures ($200 million), but expenditures in development activities have also surged. In fact, over the 2006 to 2009 time period, $31 million has been spent on development activities (54 percent on development drilling and 46 percent on field equipment), compared to just $3 million over the previous 35 years.

This trend suggests that over the last few years, producers have had a certain amount of success in exploration activities and are now looking to move into developing the resources. It shows an increased interest from the petroleum industry in the Quebec area.

These trends also reflect the transfer of technology and expertise that have successfully been employed in other places in North America, as producers in Quebec have expressed interest in developing unconventional shale gas resources in Quebec’s Utica Shale (lower Saint Lawrence) as well as other potential resources in various regions of Quebec.

Figure 1.2 displays the currently active exploration licenses issued by Quebec’s Energy branch of its Natural Resources and Wildlife Ministry (Ressources Naturelles et Faune Québec) held by various companies across Quebec’s potential oil and gas regions.

The figure reflects the potential resources available in the province, which include shale gas resources in the lower Saint Lawrence areas, crude oil and natural gas in the Gaspé Peninsula, shale oil in Anticosti Island, as well as a potentially large amount of both natural gas and crude oil resources offshore the Gulf of Saint Lawrence, in what is known as the Old Harry Field.\textsuperscript{13}

Increased interest from exploration and development companies has been unequivocally surging over the last few years in Quebec with the region holding potentially large petroleum resources.

Meanwhile, Quebec’s energy strategy (provincial energy development plan) has made it a priority to develop oil and gas resources in the Gulf of Saint Lawrence, yet the Province’s emphasis is to do so in an environmentally responsible and safe manner.

\begin{itemize}
  \item $586 million, or 94 percent of the total $626 million spent between 1971 and 2009
  \item The split in exploration expenditures in turn is: 60 percent in exploration drilling, 30 percent in geological and geophysical, and 10 percent in land related expenditures
  \item This field is the subject of a dispute on border and resource rights-related issues between the provinces of Quebec and Newfoundland and Labrador (maritime borders), as well as the Canadian Federal government (offshore petroleum rights)
\end{itemize}
Figure 1.2: Current Exploration Activity in Quebec

Source: Ressources Naturelles et Faune Québec

Further, strong public opposition to industry development has led the Quebec government to bring resource development to a halt (since 2010) while a strategic environmental assessment (SEA), with the goal of developing a framework for future offshore oil and gas, as well as shale gas exploration and development, is completed. The results and final reports of the SEA are not expected until late 2012 and for that reason, activity and development are not expected in the region over the short term.

This situation, coupled with Quebec being a fairly new potential region, leads to a high degree of uncertainty in regards to future petroleum development, and thus we exclude the region from our production analysis.

Quebec is, however, important to the Canadian oil and gas industry for various reasons including Quebec’s large population (about 23 percent of Canada’s population) which represents a large market for oil and gas and its derived products.

Quebec is also an important source of inputs, services, and manufactured products\textsuperscript{22} required for oil and gas development (including the oil sands and offshore petroleum industries), and home to various refineries and petrochemical facilities. For these reasons, Quebec benefits largely (economically) from development of the petroleum industry in other provinces.

**Atlantic Canada’s Petroleum Industry**

Recently, companies have sought to transfer knowledge and technology\textsuperscript{23} from other regions in North America and moved to explore for potential conventional and unconventional petroleum resources onshore across the Atlantic Provinces including New Brunswick, Prince Edward Island, Nova Scotia, and Newfoundland and Labrador.

This trend is however, fairly recent. The numbers of developments are scarce, and thus there is a high degree of uncertainty in regards to how future petroleum development in these areas will unfold.

Atlantic Canada is, however, home to an important segment of Canada’s petroleum industry. Natural gas development offshore shallow water Nova Scotia and crude oil development off Newfoundland and Labrador’s offshore areas have increasingly become more important over the last couple of decades in the Canadian context.

The industry has sought to explore for and develop petroleum resources around the various offshore areas while the local economy (including governments, businesses, and the general public) has reaped the benefits of such development.

\textsuperscript{22} Institut de la statistique Québec, Economic Accounts, Table Index, Real GDP by Industry: \url{http://www.stat.gouv.qc.ca/donstat/econm_finnc/conjin_econm/compteconm/tabsom0611inter.htm} (accessed on October 11, 2011)

\textsuperscript{23} Such as advances in 3D micro-seismic, a focus on drilling optimization, enhanced delineation, longer horizontal producing legs and wells, as well as on multi-stage hydraulic fracturing completions
Meanwhile, offshore projects have advanced and continue to produce resources as planned, while new projects are being built as companies move from the drawing board and exploration phases, to the development and operations stages.

This region will continue to be the focus of petroleum development in the eastern half of Canada over the medium- to long-term and it is thus the only region relevant to our analysis.

**New Brunswick**

The history of the petroleum industry in New Brunswick (NB) goes back to 1859 with the discovery of the Dover Natural Gas Field, one of Canada’s first producing gas fields located near Moncton. This field (also known as the Stoney Creek Oil and Gas Field) produced cumulative volumes in excess of 25 billion cubic feet (bcf) of natural gas as well as over 800,000 barrels of cumulative crude oil volumes between the early 1900s and 1988.24

Historical production levels from NB were however, not very significant compared to Canadian levels over time. Figure 1.3 illustrates production levels from both raw natural gas as well as crude oil from New Brunswick for the years 1971 to 1990. As a means of comparison, Canada’s raw natural gas production over the 1970s and 1980s was on average 8,500 MMcf/d and 9,400 MMcf/d, respectively; while conventional crude oil production in Canada was on average 1,400 Mb/d and 1,200 Mb/d, respectively.

**Figure 1.3: Raw Natural Gas (MMcf/d) (Left Scale) and Crude Oil (Mb/d) (Right Scale) Production in New Brunswick, 1971-1990**

Source: CAPP data25, figure by CERI


Natural gas production has been brought back to NB over the past decade with the discovery of the McCully natural gas field (part of the Horton Group in the late Devonian-Carboniferous Maritimes basin) located near Sussex and estimated to have proved plus probable reserves (2P) of 121.4 billion cubic feet (bcf) of natural gas. Of these, 107.7 bcf (or 89 percent) correspond to the working interest of a junior resource company focused on petroleum developments in Eastern Canada, Corridor Resources Inc.

Corridor Resources drilled a discovery well in September 2000 in partnership with the Potash Corporation of Saskatchewan (PCS). The company started developing the field in April 2003, producing enough sales (marketable) gas from two wells to meet a daily potash mill demand of about 2 MMcf/d. In June 2007, Corridor completed the construction of a field gathering system, a gas plant, and a 50-kilometre pipeline lateral connecting the McCully field to regional (Canadian and US) markets through the existing Maritimes and Northeast Pipeline (M&NP).

**Figure 1.4: New Brunswick’s McCully Field Natural Gas Production, 2007-2011**

Note: CDH is the ticker symbol for Corridor and corresponds to the company’s interest in production. The difference is allocated to the PCS’s potash mill.

Source: Corridor Resources

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26 Proven reserves refers to reserves that can be economically produced with a large degree of certainty from known reservoir with current technology while probable reserves are reserves which are believed to exist with a reasonable certainty based on available geological information. 2P reserves include both proven and probable reserves, but not possible reserves, which are reserves associated with a considerable amount of doubt over the technical and or financial viability of extraction.

By the end of 2010, Corridor Resources had drilled 39 wells, all of which encountered natural gas and 30 of which were completed and producing through the company’s gas gathering system and gas plant. Corridor Resources, Operations, McCully Field: http://www.corridor.ca/operations/mccully-field.html (accessed on September 12, 2011)  
Corridor also holds exploration licenses for other regions in New Brunswick and is currently in the early stages of assessing the commercial potential development of shale gas in the Sussex and Elgin sub-basins. This is possible as the company has drilled various wells of varying depths in the McCully field and within the Frederick Brook shale to evaluate the potential for future shale gas production. Corridor has also recently announced that it has made a potentially significant discovery three kilometres southeast of its McCully field in what is known as the Caledonia field, with potential natural gas and crude oil resources.

The company also has exploration licenses for both the Havelock and Millstream areas located north and west of the McCully field, respectively.

Other companies involved in exploration and development (E&D) activities in NB include 1458431 Alberta Ltd., Apache Corporation, Beneficial Energy Group, Contact Exploration, Irving Oil Ltd., Pétrolia Inc., Petroworth Resources, SWN Resources Canada, and Windsor Energy Inc. (see Figure 1.5).

High oil prices sparked a renewed interest in the Old Stoney Creek and Gas Field in 2005, and in 2007 Contact Exploration Inc. began producing oil from two horizontal wells drilled in 2006. As various directional wells were drilled in 2008 and several re-entered past-producing wells are now operational; the field’s estimated remaining proven and probable reserves are around 1.2 million barrels of oil and over 6.3 bcf of natural gas.

Potentially substantial shale gas and shale oil resources in the Horton Group are being delineated as companies expand their exploration and development efforts in the Maritimes Basin. Yet, potential for oil and gas also exists in NB’s other basins including Matapedia and Fundy, where producers have applied for the first exploration licenses over the past decade.29
Figure 1.5: Petroleum Licenses and Leases in New Brunswick, 2011

Source: New Brunswick Natural Resources

Overview of Eastern and Atlantic Canada’s Petroleum Industry and Economic Impacts of Offshore Atlantic Projects (2010-2035)

This is seen in Figure 1.5, which illustrates the different current landholdings and exploration licenses by company in NB (color coded), which are concentrated in the central and southeast regions of the province, with the light yellow areas representing unexplored (but available) areas.

As it can be observed, the province has seen renewed activity and interest over the last decade which is in part attributable to the development of pipeline and related infrastructure (M&NP and Enbridge Gas New Brunswick) in the late 1990s, which provides producers with access to markets as well as growth prospects for the industry in the region.

The provincial government has identified natural gas exploration and development, together with its related industrial activity, as having potentially significant economic benefits for the region including increased capital investments, royalties and taxes, economic diversification, as well as employment creation.

The provincial government recognizes the importance of improving regulatory efficiency and effectiveness, as well as data management and dissemination, in encouraging exploration activity. Meanwhile, the government supports development of the industry in a responsible and sustainable manner, ensuring the safety and security of the people as well as the groundwater supply, and thus have recently introduced stricter regulatory requirements related to petroleum development.  

Development of the petroleum industry in New Brunswick has been encouraging over the past decade, yet there is still a high degree of uncertainty in regards to the potential of available resources. While early results have been encouraging, production levels from the region are currently insignificant in regards to national levels.

And while there is potential for this to change over the medium- to long-term, the current high degree of uncertainty means that this region will not be considered in our production analysis.

**Prince Edward Island**

Canada’s first offshore well was drilled off Prince Edward Island (PEI) in 1943. Exploration activities in the island have demonstrated the presence of petroleum reservoirs, including a discovery made offshore near East Point in the 1970s. Twenty wells were drilled between 1944 and 2007, with one well in North Point in the east edge of the province testing 5.5 million cubic feet per day (natural gas).

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Currently, there is no petroleum production in PEI, but in recent years several companies have conducted seismic programs, while exploratory drilling indicates some potential for natural gas.

The petroleum industry in the island is in its infancy, yet companies have leased over a million acres for petroleum exploration purposes. Figure 1.6 illustrates the areas of the province where petroleum exploration rights have been issued and the correspondent current holders.

Much of the province is underlain by seams of coals of various thicknesses which are too deep for economic extraction but hold potential of future development in the form of CBM or natural gas from coal. A mapping study of the island’s coal seams carried out by the Atlantic Geoscience Centre has estimated the potential on mainland PEI to be about 7.6 trillion cubic feet (tcf).

Figure 1.6: Prince Edward Island Rights Holder Map, 2011

While the industry has shown interest over the last decade in petroleum exploration and development on the island, and preliminary results of the resource potential are encouraging, there is no clear indication as to how the petroleum industry will develop in the province over the short to medium term. There is no doubt that PEI could potentially become a significant producer of CBM although it lacks commercially viable projects. For this reason, PEI is excluded from our production analysis.

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33 CAPP, Canada’s Industry, Industry Across Canada, Prince Edward Island: http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/PrinceEdwardIsland.aspx?lthQ0Tz2zk0U (accessed on September 12, 2011)


Nova Scotia

Offshore

Nova Scotia’s first offshore well was drilled in 1967, and the first discovery was at Sable Island in 1971. More than 130 exploratory wells have been drilled offshore Nova Scotia, yielding 24 significant discoveries.36

Cohasset-Panuke Project

Canada’s first offshore oil project, the Cohasset-Panuke project operated from 1992 to 1999, producing a total of 44.5 million barrels (MMb) of crude oil from two fields located about eight kilometres apart and about 41 kilometres southwest of Sable Island.

A platform was located at each field as seen in Figure 1.7 (top). Wells were drilled through a series of jackets at each platform using the Rowan Gorilla III jack-up drilling rig, also used as the production facility.

The Panuke field produced oil and gas from 4 different wells, while the other part of the project produced oil and gas from 12 wells connected to the Cohasset field.

Produced natural gas was mainly re-injected into the reservoirs to maintain reservoir pressure in order to keep the oil flowing; some was also used for on-site operations such as powering machinery and equipment.

About 64 percent of the total 44.5 MMb produced were produced from the Cohasset field (28.3 MMb), while the remaining 36 percent (16.2 MMb) were produced from the Panuke field.

Figure 1.7 (bottom) illustrates the historical production levels from the Cohasset-Panuke project from the start of operations until shut-down.

Production flowed between fields via a subsea line and it was processed at facilities located in the drilling rig which alternated locations between fields as needed.

After processing, the oil was stored in the Apollo tanker, which was moored to a nearby buoy, and then transferred to a shuttle tanker which delivered it to markets.

The project was originally developed by LASMO Nova Scotia Ltd., in partnership with Nova Scotia Resources (Ventures) Limited. PanCanadian (now EnCana) acquired LASMO’s 50 percent ownership in 1996 and became the project’s operator.

The project is now decommissioned and environmental follow-up was completed in 2009-2010.37

36 CAPP, Canada’s Industry Across Canada, Nova Scotia: http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/NovaScotia.aspx#1nNkZRisFbE (accessed on September 12, 2011)
Figure 1.7: Cohasset-Panuke Project (top) and Related Crude Oil Production (Mb/d) (bottom), June 1992-December 1999

Source: Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) data and picture, production figure by CERI


November 2011
Sable Offshore Energy Project (SOEP)\textsuperscript{38}

The Sable Offshore Energy Project (SOEP) is the first offshore natural gas development in Canada and the first commercial development of significant natural gas reserves in Atlantic Canada (and outside the WCSB).

The project has a maximum design capacity of 510 million cubic feet per day (MMcf/d) of raw gas, 20 (Mb/d) of natural gas liquids (NGLs) (mainly condensate), and 461 MMcf/d of sales (marketable) gas.

The project fields were discovered in the 1970s and are part of the Scotian shelf located near Sable Island (hence its name) approximately 225 km off the east coast of Nova Scotia. SOEP is also the largest construction project ever undertaken in Nova Scotia (NS). This project is a shallow water project at a depth between 20-80 metres.

This multi-billion project is an economic venture led by ExxonMobil Canada Properties Ltd. (operator) that includes Shell Canada Limited, Imperial Oil Resources, Pengrowth Energy Corporation, and Mosbacher Operating Ltd.

It originally involved the development of six major fields (Alma, Glenelg, North Triumph, South Venture, Thebaud, and Venture) and it is divided into two “tiers” of offshore development.

Tier I was completed in December 1999 at a cost of over $2 billion (nominal) including the development costs of the Thebaud (1999), North Triumph (2000), and Venture (2000) gas fields through three platforms (see Figure 1.8, top), as well as the costs associated with a subsea pipeline to shore, construction of a gas processing plant at Goldboro (NS), a natural gas liquids (NGLs) pipeline to Point Tupper (NS), and a fractionation plant at Point Tupper.

First sales gas flowed on December 31, 1999 as shown in Figure 1.8 (bottom).

\textsuperscript{38}Various sources including:
CAPP, Canada’s Industry, Industry Across Canada, Nova Scotia: \url{http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/NovaScotia.aspx#z3rosCh2G7wU} (accessed on September 13, 2011)
ExxonMobil, Sable Project, Overview: \url{http://www.soep.com/cgi-bin/getpage?pageid=1/0/0} (accessed on September 13, 2011)
Newfoundland and Labrador Oil & Gas Industries Association, Industry Information, Regional Infrastructure: \url{http://www.noianet.com/regionalinfrastructure.aspx} (accessed on September 13, 2011)
Figure 1.8: Sable Offshore Energy Project (SOEP) (top), Natural Gas Production (MMcf/d) (Left Scale) and Remaining Recoverable Reserves (bcf) (Right Scale) (bottom), December 1999-December 2009

Source: Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) data and picture, production figure by CERI
Tier I development included the installation of central facilities (platform) at Thebaud for production, utilities, and accommodation purposes. Satellite (unmanned wellhead) platforms located at the Venture and North Triumph fields, were also installed as part of Tier I development. These are controlled and monitored remotely from the Thebaud central platform.

Hydrocarbons from the satellite platforms are moved through a system of subsea flow-lines (200 km total length) to the central Thebaud pre-processing platform. Raw gas is separated and dehydrated (pre-processed) at the central platform and then transported through a subsea production gathering pipeline (200 km) to the processing plant in Goldboro.

There, the gas is further processed, sending sales gas to local markets in the United States (US) and Canada through the M&NP, while NGLs are transported (via pipeline) to the fractionation plant in Point Tupper, where they are further processed before being sold.

A total of 14 development wells have been drilled using jack-up rigs in association with Tier I development, including 5 at the Thebaud field, 7 at the Venture field, and 2 at the North Triumph field.

Tier II (estimated to cost over $1 billion, nominal) involved the development of the Alma field (and platform) beginning in late 2003, while production from the South Venture was brought online by late 2004. Tier II development also involved the installation of a $700 million plus (nominal) compression platform in 2006 which is bridge-connected to the central processing (Thebaud) facility. The compression platform began operation in early 2007. A total of 7 development wells have been drilled in the Alma (4) and South Venture (3) fields.

Development of the Glenelg field, part of Tier II development, and expected to have started production in the latter half of the 2000s, has been cancelled as a result of reserves revisions (which can be seen in Figure 1.8, bottom), and it is clear (as of the time of writing) that the field will not be developed.39

The operator has also publicly stated that further than the last stage of drilling which was completed in 2008 (Alma), there will be no further development of the project’s surrounding fields.40

While it is apparent from Figure 1.8 (bottom) that production from the SOEP peaked in late 2001 (at 604 MMcf/d) and has been in a slow decline ever since, the project is expected to

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continue to produce natural gas and some liquids volumes over the short to medium term (the original project lifespan is 25 years) as substantial recoverable volumes remain (about 500 bcf).

However, this development will be limited by the project economics (increasing costs vs. shrinking revenues). In the short term, the Nova Scotia government expects that recent exploration activity around the vicinity of the SOEP project will bring about significant gas discoveries which will allow maintaining future production levels as producers seek to take advantage of the existing infrastructure.

This project has been in operation for over 10 years and it is expected to continue operating for many more. While most of the capital required to build the project has already been allocated, there are significant costs associated with operating and maintaining the existing infrastructure and facilities associated with the SOEP. In fact, data collected from the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB), the Canadian Association of Petroleum Producers (CAPP) and the Government of Nova Scotia indicates that over the last few years (2005-2009) these expenditures have been in the range of close to $200 million (nominal) annually.

CERI’s analysis indicates that over the short to medium term, this project will continue to contribute to the local economies through its expenditures, thus contributing to create employment, value added, as well as royalty and taxation revenues for the different levels of government. For those reasons, this project is included in our analysis.

**Deep Panuke Project**

The *Deep Panuke* pool will produce natural gas from a deep carbonate reservoir located below the seafloor under the decommissioned *Cohasset-Panuke* project (discovered in 1999). EnCana Corporation’s *Deep Panuke* offshore gas development project application was filed in November 2006 and after being subject to public review and hearings (review process), the project was sanctioned (approved) in late 2007.

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41 Various sources including:
CAPP, Canada’s Industry, Industry Across Canada, Nova Scotia: [http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/NovaScotia.aspx#z3rosCh2G7wU](http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/NovaScotia.aspx#z3rosCh2G7wU) (accessed on September 13, 2011)
Figure 1.9: Deep Panuke Project and Associated Infrastructure

Source: EnCana Corporation, CNSOPB
Deep Panuke will be located 250 km southeast of Halifax at a depth of 45 metres (shallow water), with a maximum design capacity of 300 MMcf/d and an expected average production life of 14 to 15 years with the possibility of an extension.

Estimated recoverable resources are in the range of 400 to 900 bcf with a mean of 659 bcf of recoverable sales gas. The project is currently in the development phase (construction and pre-production), and first gas is expected in late 2011/early 2012.

The project involves the construction of a jack-up platform at its production field centre (PFC) or mobile offshore production unit (MOPU), for offshore production and processing purposes, tied back to production wells with subsea flow-lines and umbilicals.

Production wells will include completing four previously drilled wells and drilling two new wells, one for production and one for acid gas injection (see Figure 1.9, top). Additional (up to 3) subsea production wells could be drilled after a year of operations, if required. All wells will have horizontal legs and will be connected to the MOPU.

Originally, the export system consisted of a subsea pipeline delivering sales gas to either an interconnection with the M&NP pipeline at Goldboro, or a subsea pipeline tied at a close point on the SOEP pipeline route (Figure 1.9, bottom). The gas processing system at the MOPU will include inlet compression, separation, sweetening (Deep Panuke being a sour gas reservoir), dehydration, export compression, and measurement units.

By the end of 2007, EnCana selected Single Buoy Moorings Inc. for the provision and operation of the project’s MOPU. Acergy Canada Ltd. was selected in early 2008 to engineer, procure, install, and commission the infield flow-lines and umbilicals (part of the subsea program), expected to be installed by 2011.

Accent Engineering Consultants was selected for the design of the subsea protection structures in 2008, and in the same year the first pipe shipments for the project arrived in Sheet Harbour, where they were concrete-coated previous to offshore installation. By 2009, construction of a new supply vessel and a 10-year charter contract was awarded to Atlantic Towing Ltd., while the project’s flare tower fabrication began at Aecon Fabco’s Pictou facility.

In 2010, EnCana and its contractors moved along with its drilling and completions program, its subsea program, installation of the export pipeline to Goldboro (direct connection to M&NP option, EnCana’s own 175 km pipeline), completed construction of the PFC, as well as the supply boat.

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42 Umbilicals are defined as either external electrical lines or fluid tubes which connect a portion of the system with another; as well as a control line attached to a remote piece of equipment such as a subsea wellhead, that provides hydraulic or electrical control, but that can also serve to inject chemicals as needed (Oil & Gas Field Technical Terms Glossary, Umbilical: [http://oilgasglossary.com/umbilical.html](http://oilgasglossary.com/umbilical.html) (accessed on October 11, 2011)
In 2011 EnCana has continued with its subsea program (hook-up and commissioning of subsea facilities), while the PFC (or MOPU) that was transported from the Middle East (Dubai) to Nova Scotia, is expected to be hooked-up and commissioned in the second half of the year. At that point, the export pipeline will be connected to the facilities leading to first gas by the end of 2011 or early 2012.

According to company estimates, the project costs are approximately $430 million on pre-development expenditures (exploration, etc.) spent between 1998 and late 2006, close to $700 million in development expenditures (2007-2011), plus an additional $120 million to $260 million on possible additional drilling expenditures (2012), as well as an estimate of close to $150 million per-year in operating expenditures over the life of the project.

This translates into a total of $2,100 million over 14 years, or $2,250 over 15 years in operating expenditures. The project’s total life-cycle cost is thus in a range of $3,350 million (1 additional well drilled, 14 years of operation) to $3,640 million (3 additional wells drilled, 15 years of operation).

While a large portion of the capital associated with development of this project has already been allocated and spent, operation expenditures over the project’s lifetime will contribute to the local economies, and the project will help to maintain a certain level of industry activity in the region over the medium to long term. This project is therefore included in our analysis.

**Other Recent Developments**

Nova Scotia’s offshore activity, since the early years of the industry, has been focused on the Scotian Basin (zoomed-in section in Figure 1.10, color-coded by company or licence holder). More specifically, the Sable and Abenaki sub basins, as well as the Hinge zone around the Sable Island area.

Two offshore areas are currently under moratorium including The Gully (a marine protected area), as well as the George’s Bank area (US-Canada offshore borders, Massachusetts-Nova Scotia).

Most of the areas where exploration and development have occurred are shallow water areas with depths below 200 metres and within a 150 km radius from Goldboro (lightest shade of blue in Figure 1.10).

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43 Costs for the Deep Panuke project are given in 2006 dollars as given in the project’s development plan, available at: [http://www.encana.com/operations/canada/deeppanuke/filingsapplications/](http://www.encana.com/operations/canada/deeppanuke/filingsapplications/) (accessed on October 21, 2011) and are given for illustrative purposes only. These figures are adjusted to nominal and subsequently 2010 real dollars in our analysis.

44 Depending on project performance.

Figure 1.10: Offshore Nova Scotia Current Exploration and Production Licenses, and 2011 – 2012 CNSOPB Call for Bids (CFB) Parcels

Source: CNSOPB


November 2011
While there are currently four active exploration licenses (all held by Nova Scotia based companies including Amonite Nova Scotia Corporation, Scotia Exploration Inc., and Shin Han F&P Inc.), there are over 60 inactive exploration licenses (mostly held by major oil and gas companies).

Meanwhile, there have historically been 24 wells that led to significant discoveries declarations or licenses (SDL), mostly in the Sable Island region, of which all but one (EnCana’s Panuke PP-3C in 2006) were drilled prior to 1990. From these, a total of 8 have been turned into declared commercial discoveries (Cohasset, Panuke, Thebaud, Venture, North Triumph, Alma, South Venture, and Deep Panuke) between 1990 and 2009.

Recently, Nova Scotia’s Department of Energy’s Play Fairway Analysis (PFA) project, a comprehensive geosciences program specifically targeted at understanding and reducing geological risk, has identified diverse rich hydrocarbon potential in Nova Scotia’s offshore region.

This includes shallow water small-scale traps with oil and gas potential, as well as large-scale potential traps that could contain natural gas and condensate along the north-eastern part of the margin in deep water (darker shades of blue in Figure 1.10), as well as a predicted oil-charged play in the south-west of the margin.

The potential estimates include un-risked, yet-to-be-found 120 trillion cubic feet (Tcf) of natural gas and 8 billion barrels (Bb) of oil.\(^47\)

For the fiscal year 2011-2012, the CNSOPB is issuing a call for bids for 8 parcels situated approximately 200 km offshore and south-west of the Sable Island region, located in the Shelburne sub-basin at depths between 1,000 and 4,000 metres (see Figure 1.10, centre, red blocks).

This indicates the CNSOPB’s focus on promoting exploration in deepwater areas and areas away from the Sable Island region over the medium- to long-term, as well as the government’s focus on having companies exploring around the newly identified potential areas.

**Onshore\(^48\)**

Petroleum exploration in Nova Scotia dates back to the 1800s with oil wells drilled around the Cape Breton area. Some of the same lands that were once mined for coal in the province are now being explored for their natural gas potential. CBM and shale gas exploration are making the onshore a new frontier for Nova Scotia’s energy industry.


The province currently has two production agreements for CBM (East Coast Energy Inc. in the Stellarton area, and Donkin Tenements in the Cape Breton area) and one production lease for shale gas (Elmworth Energy/Triangle Petroleum Corporation).

Various companies are currently actively involved by drilling exploratory wells and completing seismic programs to evaluate the regions’ resource potential. These companies include: Forent Energy, Stealth Ventures Ltd., Petroworth Resources Inc., St. Brendan’s Exploration Ltd., and Eastrock Resources.

As in other regions of the country, public concern around the practice of hydraulic fracturing for shale gas development has prompted various levels of government to examine the potential environmental issues through an internal review. This review is intended to examine other jurisdictions where the process is used, in order to identify and establish best practices. The public will have the opportunity to get involved and comment on the areas covered by the review. The results will lead to recommendations surrounding the regulations of hydraulic fracturing in the province, and are expected by early 2012.

While there seems to be potential for both CBM and shale gas development onshore Nova Scotia, the local industry is still in its infancy and it is thus difficult to develop a reliable projected path for resource development in this area.

Newfoundland and Labrador

Offshore

Offshore Newfoundland and Labrador (NL) there are significant commercial deposits of crude oil, and a potential for natural gas (over 1 Tcf estimated by the Canada-Newfoundland Offshore Petroleum Board [CNLOPB]). No marketable natural gas is currently being produced in the region.49

Drilling for offshore petroleum resources in the province started in the late 1960s, around the same time it did in Nova Scotia. By the end of 2009, over 1.8 billion barrels (Bb) of crude oil reserves (proven + probable: 2P) remained in the Jean d’Arc Basin, which had original estimated 2P reserves of over 2.9 billion barrels, thus indicating cumulative production of over 1 billion barrels of crude oil to year-end 2009.50

Currently, there are four producing fields in the Jean d’Arc Basin including Hibernia (first oil in 1997), Terra Nova (2002), White Rose (2005), and North Amethyst (2010, part of White Rose project). Existing operating offshore crude oil projects correspond to the fields being developed including Hibernia, Terra Nova, and White Rose.

49 CAPP, Canada’s Industry Across Canada, Newfoundland and Labrador: http://www.capp.ca/canadaIndustry/industryAcrossCanada/Pages/NewfoundlandLabrador.aspx#XhKAzTQjWTVC (accessed on September 23, 2011)
50 As confirmed by CAPP and CNLOPB data. This also applies when discussing individual projects below.
One project is currently under development in the Jean d’Arc Basin, the *Hebron* project, which will develop the Hebron/Ben Nevis fields (4 pools in total), with estimated resources of 2,620 million barrels of crude oil (789 million recoverable), as well as substantial potential volumes of natural gas and NGLs. These projects are further discussed below.

Figure 1.11 illustrates the production levels of offshore crude oil from Newfoundland and Labrador, as well as a comparison of production levels with conventional crude oil (excludes bitumen and synthetic crude oil) from the Western Canada Sedimentary Basin (WCSB) including Alberta, Saskatchewan, Manitoba, British Columbia, and the Northwest Territories, for the time period from 1997 (year *Hibernia* started producing) to 2009.

**Figure 1.11: Offshore Newfoundland and Labrador Crude Oil Production (Mb/d) (top), and Comparison with WCSB Conventional Crude Oil Levels (bottom), 1997-2009**

Source: CAPP data, Canada-Newfoundland and Labrador Offshore Petroleum Board (CNLOPB)\(^{51}\) data, figures by CERI

As can be observed from Figure 1.11, crude oil production from offshore Newfoundland and Labrador has increased rapidly over the past decade and has increasingly become an important component of Canadian conventional crude oil production, accounting for between 20 to 25 percent of the total over the 2006 to 2009 time period, and averaging 318 Mb/d over the same timeframe.

Meanwhile, conventional crude oil production levels from the WCSB (excluding bitumen and synthetic crude oil production) have exhibited a declining trend over the last few decades, which in CERI’s view could be reversed over the short- to medium-term but expected to continue over the long-term, yet that discussion is beyond the scope of this report.  

*Hibernia*  

The Hibernia Field is located on the Grand Banks area offshore NL, approximately 315 km south-east of St. John’s, at a depth of about 80 metres in the Jean d’Arc Basin. The field was first discovered in 1979 by Chevron and its partners, and between 1979 and 1984 ExxonMobil drilled nine additional wells to delineate the field.

The field has two principal reservoirs including Hibernia (3,700 metres in depth) and Ben Nevis/Avalon (BNA) (2,400 metres in depth). By 1985, a significant discovery area for the region was declared.

The *Hibernia* project was brought about in the early 1990s by a consortium of companies including ExxonMobil Canada Properties (operator and majority interest-holder), Chevron Canada Resources, Suncor Energy (holds the original Petro-Canada share), the Canada Hibernia Holding Company (CHHC, a subsidiary of the Canada Development Investment Corporation, part of the Government of Canada), Murphy Oil Corporation, and Norsk Hydro Canada Oil & Gas Inc. (now Statoil Canada).

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53 Various sources, including:

- CNLOPB, Resource Management, Statistics: (see link above)

November 2011
Construction of the project began in 1991 consisting of a fixed platform with a daily production capacity of over 200 Mb/d and three different main components including the topsides, a gravity based structure (GBS), and an offshore loading system (OLS) (see Figure 1.12).

The topside structure is made up of five super-modules including the M10 processing module that separates the produced oil from natural gas and water. Here, water is treated and sent back to the ocean or injected in the reservoir as needed, while natural gas is re-injected into the reservoir in order to maintain an optimal pressure for crude oil production, or used as fuel for the platform operations. The M20 wellhead module houses the drilling operations where two mobile drilling derricks are mounted, with the ability to drill two wells at a time. The M30 mud module produces drilling mud, pumps it down the drill pipe and through holes to cool the drill bit while preventing the well from collapsing, while washing cuttings away from the bottom of the hole.

The M40 utilities module houses all the equipment required for power generation, heating, ventilation, and air conditioning (HVAC), as well as the water distribution system. The M50 module is the accommodations module consisting of eating and sleeping facilities, as well as offices, recreation, and meeting areas. This last module also houses the temporary safe refuge (TSR) for emergency purposes, as well as the lifeboat station, helideck, and the skyscape evacuation system.

The topsides are supported by a large (550,000 tonnes) GBS which was constructed in a near-shore deepwater construction facility in Bull Arm, Trinity Bay. The GBS extends 111 metres from the sea floor to the ocean surface, has a storage capacity of 1.3 million barrels (MMb) of crude oil, and is specially designed to withstand the impact of sea ice and icebergs to allow for year-around production.

The OLS consists of subsea pipelines connected to the GBS storage facility, a subsurface buoy and flexible loading hoses which feed a shuttle oil tanker. An identical spare (reserve) OLS facility exists in order to ensure constant production flow. Shuttle tankers can deliver marketable oil to markets or to a transhipment terminal, the Newfoundland Transhipment Terminal (NTT), located at Whiffen Head.

In the early part of 1997 the topsides were mounted onto the GBS to form one integrated unit. By mid-year the unit was towed out to the target area where it later started drilling operations, and by the end of the year (November), first oil was produced. Construction of the facilities was estimated to cost close to $6 billion (nominal), while annual (operating) expenditures are estimated to average $400 million (nominal) per year.

In 2009 the CNLOPB approved an amendment to the original Hibernia development plan which will allow the project operators to develop the Hibernia South Extension (HSE) area. In 2010, the provincial government finalized agreements with industry for the development to go forward, while the provincial government has also assumed a 10 percent equity share ($30 million) in the remaining area of the project through Nalcor Energy Oil & Gas.
Figure 1.12: Hibernia Project Concept (top), Topsides and Integrated Unit Tow-out (middle), Crude Oil Production (Mb/d) (Left Scale) and Remaining Recoverable Reserves (MMb) (Right Scale) (bottom), 1997 – 2009

Source: CNLOPB data and pictures, Hibernia pictures, production figure by CERI

54CNLOPB, Information & Reports, Decision Reports, Decision 86.01, Application for Approval Hibernia Development Plan – English: http://www.cnlopb.nl.ca/news/pdfs/d86_01e.pdf (accessed on September 27, 2011)
HSE will develop the AA blocks with estimated recoverable reserves of 48 million barrels, and the HSE unit with estimated recoverable reserves of 167 million barrels. The agreement allows for the Hibernia Management Development Company Ltd. to develop the HSE unit using existing production facilities and supporting infrastructure, as well as by adding subsea infrastructure, extending the production life into the late 2030s, possibly to 2040.

These estimates include continued development of the Hibernia A and B pools and the Ben Nevis/Avalon (BNA) reservoir, all of which are expected to continue economic production levels until the late 2030s/close to 2040; as well as new production from the AA blocks starting in 2009-2010 (until about 2025) and the HSE unit starting in 2013.

As of year-end 2009, there were a total of 34 producing wells tied to the Hibernia project. On that same year, the project produced an average of 126 Mb/d, including 108 Mb/d from the Hibernia reservoir and over 17 Mb/d from the Ben Nevis/Avalon reservoir as shown in Figure 1.12.

The field’s initial estimated recoverable crude oil reserves (Proven + Probable: 2P) include 1,213 million barrels (MMb) in the Hibernia Reservoir (including the B pool, 963 MMb; the AA blocks, 48 MMb; the A pool, 35 MMb; and the HSE unit, 167 MMb), as well as 182 MMb in the BNA, for a total of 1,395 MMb.

By year-end 2009 (see Figure 1.12, bottom), remaining recoverable reserves of the Hibernia Field were about 728 MMb (80 percent in the Hibernia Reservoir). This indicates cumulative production from the Hibernia project of 667 MMb (49 percent of initial recoverable reserves) to year-end 2009.

Given the long-term nature of this project, the large volumes of remaining recoverable reserves, as well as the existing development plans and the amount of related available information, this project is relevant to and included in our analysis.

**Terra Nova**

The Terra Nova field is located on the north-eastern Grand Banks at about 350 km south-east of St. John’s, at a depth of about 100 metres. The field was discovered in 1984 by Petro-Canada (now Suncor Energy) and its partners. Eight wells were subsequently drilled to define (delinate) the structure of the field, and by 1985 the Terra Nova field was declared a significant discovery area. The field, located in the Jean d’Arc Basin, is divided into three different areas known as the Graben, the East Flank, and the Far East.

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56 Various sources, including:

CNLOPB, Newfoundland and Labrador Department of Finance, Newfoundland and Labrador Department of Natural Resources, and Newfoundland and Labrador Oil & Gas Industries Association (NOIA) (see links above)

Figure 1.13: Terra Nova Project Concept (top), Crude Oil Production (Mb/d) (Left Scale) and Remaining Recoverable Reserves (MMb) (Right Scale) (bottom), 2002-2009

Source: CNLOPB data, Suncor Energy picture, production figure by CERI
The *Terra Nova* project is an offshore crude oil development project by a consortium of companies led by Suncor Energy (operator) and including ExxonMobil Canada Properties, Statoil Canada Ltd., Husky Oil Operations Ltd., Murphy Oil Company Ltd., Mosbacher Operating Ltd., and Chevron Canada Resources.

The project consists of a steel floating, production, storage, and offloading (FPSO) vessel with a design storage capacity of close to 1 MMb, as well as a series of producing and injector wells (water and natural gas) which offload marketable crude oil to offshore tankers (see Figure 1.13, top).

*Terra Nova*'s FPSO is one of the largest ever built at 202 metres long, close to 46 metres wide and more than 18 stories high, with the capacity to house up to 120 people.

Wells are pre-drilled by a semi-submersible mobile offshore drilling unit (MODU) and placed on glory holes (excavations in the seafloor)\(^57\) which protect the equipment from icebergs. Several kilometres of flow-lines move hydrocarbons and water to and from the wells where these liquids are used/separated, extracted, and injected as needed in a similar fashion to that of the Hibernia Project.

 Marketable crude oil is offloaded from the FPSO to shuttle tankers, which take the product to market. The FPSO is connected to the subsea flow-lines through a spider buoy, which in turn serves as the mooring point for the vessel and the pathway for flows between the FPSO and the reservoir. The spider buoy is designed to be easily disconnected from FPSO in the event of an emergency.

Production from *Terra Nova* began in 2002. The project’s capital expenditures (development) were close to $3 billion (nominal), while annual operating expenditures are about $300 million (nominal). The project expected production life (from first oil) is approximately 20 years, operating until approximately 2020.

As of year-end 2009 there were a total of 15 producing wells tied to the Terra Nova project. During that same year, the project produced an average of 80 Mb/d. As shown in Figure 1.13 (bottom), the field’s initial estimated recoverable crude oil reserves (Proven + Probable: 2P) were 419 MMb.

By year-end 2009 these are estimated at 133 MMb (32 percent of the total), indicating cumulative production of the Terra Nova project of 286 MMb by year-end 2009 (or 68 percent of the estimated initial recoverable reserves).

Given the long-term nature of this project, the significant volumes of remaining recoverable reserves, as well as the existing development plans and the amount of related available information, this project is relevant to, and included in our analysis.

\(^57\) A glory hole refers to an excavation in the seafloor that protects the installed production equipment, such as the wellheads, from ice and iceberg conditions
**White Rose/North Amethyst**

The White Rose field was discovered in 1984 by Husky Energy and its partners. After initial discovery, eight wells were drilled to delineate the field’s structure, and by 2004 a significant discovery license was issued by the CNLOPB.

The field is located 350 km east of St. John’s, and sits at a depth of about 120 metres. The field consists of one main field in the eastern margin of the Jean d’Arc Basin, White Rose (South Avalon Reservoir), as well as three satellites including the North Amethyst (discovered in 2003), South White Rose (SWR), and West White Rose (WWR) extensions.

The project is operated by Husky Energy (majority owner) and it is a joint venture with Suncor Energy. The government of NL owns a 5 percent equity stake in the satellite fields through Nalcor Energy Oil & Gas.

*White Rose* uses an FPSO (as does the *Terra Nova* project, described above), the *SeaRose*, connected to both subsea flow-lines and risers from the subsurface reservoirs to the FPSO, as well as to shuttle tankers.

The subsea equipment is controlled by electrical and hydraulic umbilicals tied to the *SeaRose*, which are positioned in glory holes to prevent iceberg damage. Similar to the Terra Nova project, wells are drilled via a mobile offshore drilling unit.

Production from *White Rose* began in 2005. The project’s capital expenditures (development) were estimated at over $2 billion (nominal), while annual operating expenditures are estimated at over $400 million (nominal).

As of year-end 2009 there were a total of 9 producing wells tied to the *White Rose* project. During that same year the project produced an average of 62 Mb/d from the White Rose field alone.

As shown in Figure 1.14 (bottom), the field’s initial estimated recoverable crude oil reserves (Proven + Probable: 2P) were 352 MMb including 284 MMb in the BNA reservoir (200 MMb in White Rose, 60 MMb in West White Rose, and 24 MMb in South White Rose) as well as 68 MMb in the North Amethyst reservoir.

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Figure 1.14: White Rose Project Concept (top), Related Crude Oil Production (Mb/d) (Left Scale) and Remaining Recoverable Reserves (MMb) (Right Scale) (bottom), 2004-2009

Source: CNLOPB data and picture, production figure by CERI
By year-end 2009 these are estimated at 214 MMB (61 percent of the total recoverable reserves), indicating cumulative production from the White Rose project of 137 MMB by year-end 2009 (or 39 percent of the initial estimated recoverable reserves).

Crude oil production from the North Amethyst field commenced in 2010; meanwhile, pilot well-drilling in the West White Rose (second satellite field) commenced in the same year following approval from the CNLOPB. The South White Rose development was granted regulatory approval in 2007, and the project owners are currently assessing development schedule options.

Husky is contemplating the possibility of using a GBS to develop the project’s future satellite fields. This GBS will be limited to wellhead capabilities including pumping and drilling, in contrast with Hibernia’s GBS which serves as a storage facility as well.

Given the long-term nature of this project, the large volumes of remaining recoverable reserves, as well as the existing development plans and the amount of related available information, this project is relevant to, and included in our analysis.

**Hebron**

The Hebron heavy oil asset was discovered in 1981 (Hebron Field) and it consists of three main fields including the Hebron Field, the West Ben Nevis Field, and the Ben Nevis Field, with a total of four pools.

These fields are located 350 km offshore in the Jean d’Arc Basin at a depth of 92 metres, north of the Terra Nova field and south of the Hibernia and White Rose fields. NL’s fourth stand-alone offshore project contains an estimated 769 million barrels of recoverable (heavy) oil reserves.

The project will be developed as a consortium of partners including ExxonMobil Canada Properties (operator), Chevron Canada Ltd., Suncor Energy Inc., and Statoil Canada Ltd. The provincial government has purchased a 5 percent equity stake at a cost of $110 million through Nalcor Energy Oil & Gas. First oil from the project is expected in 2017.

The project will consist of a stand-alone GBS, topsides, and an offshore loading system (OLS), making it in practice very similar to the Hibernia project (see Figure 1.15). This design was chosen after giving consideration to various other options including one based on subsea wells tied back to the Hibernia platform; one consisting of an FPSO facility with connections to subsea wellheads, manifolds, pipelines, and risers (similar to the Terra Nova and White Rose projects); and a hybrid FPSO with a wellhead gravity base structure (WHGBS). All of these options, except for the chosen design, required the use of a mobile offshore drilling unit (MODU).

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59 Various sources, including:
CNLOPB, Newfoundland and Labrador Department of Finance, Newfoundland and Labrador Department of Natural Resources, and Newfoundland and Labrador Oil & Gas Industries Association (NOIA) (see links above)

60 Estimates include pools 1, 3, 4, and 5
Figure 1.15: Hebron Project and Associated Infrastructure (Concept)

Source: CNLOPB, Hebron Project
The GBS will be made of reinforced concrete in order to withstand local Arctic conditions. The structure will be fixed to the ocean’s floor and will support the integrated drilling and production topsides, while also having the capacity to store 1.45 million barrels of crude oil.

In 2010, the GBS front end engineering design (FEED) and site preparation contracts were awarded to Kiewit-Aker contractors, with the option to provide engineering, procurement, and construction services. Construction of the GBS is expected to start in 2012 at the bull arm industrial fabrication site (same site used for the construction of Hibernia’s GBS).

The topsides facilities will be designed in modules including a drilling support module, derrick-equipment set (drilling) module, a flare boom, a utilities and processing module, and the living quarters module which will include a helideck and lifeboat stations. The production facilities will be able to handle all the operations requirements including drilling and production of crude, storage and export, gas management, as well as water injection and management. In 2010 the topsides FEED contract was awarded to Worley-Parsons Canada Services Ltd. Construction on the topsides is expected to begin in 2012-2013.

The offshore loading system (OLS) will unload crude oil onto shuttle tankers which will deliver the product to either the Newfoundland Transhipment Terminal (NTT) or directly to market. The main OLS system will consist of two main offshore pipelines connecting the GBS to riser bases, with a capacity to offload crude to the tanker at a rate of 50 Mb/hour.

The project design life is for 30+ years with the capacity to be expanded for up to 50+ years depending on the project’s success. Total project costs are estimated at over $14 billion (nominal), including $600+ million (nominal) already incurred in pre-development expenditures, over $9 billion (nominal) in project development capital expenditures such as project administration, commissioning of the GBS, topsides, OLS, and drilling cost, and close to $4 billion in subsea development capital costs. Operating expenditures are estimated at over $200 million (nominal) on average over the project’s lifetime (2017-2046).

Given the long-term nature of this project, the large volumes of estimated recoverable reserves, and the expenditures information available, this project is included in our analysis.

Other Recent Developments

There are currently over 20 active exploration licenses (ELs) for the Grand Banks region, 9 for the West Coast region and 4 related to the Labrador offshore region (see Figure 1.16). There are over 40 currently active significant discovery licenses (SDLs) in the Grand Banks region, most of which are either associated with or close to current project/field developments within the Jeanne d’Arc Basin, but also including the Mizzen finding in the Flemish Pass sub-basin (discussed below). In the Labrador region, 5 SDLs were issued in the late 1980s.

61 Includes the pool 3 development and subsea program
62 CNLOPB, Newfoundland and Labrador Department of Finance, Newfoundland and Labrador Department of Natural Resources, and Newfoundland and Labrador Oil & Gas Industries Association (NOIA) (see links above)
Figure 1.16: Offshore Newfoundland and Labrador Areas and Current Active Licenses

Source: CNLOPB, Newfoundland and Labrador Department of Finance
Currently there are 10 production licenses (PL) in the Grand Banks region including 2 associated with the *Hibernia* project, 3 with *Terra Nova*, and 5 related to the *White Rose* project.

The latest SDLs were issued in 2010 and 2011. Before then, the previous SDLs were issued in 2004. The most recent SDLs were issued to Statoil Canada Ltd. (in conjunction with Husky Oil Operations Ltd.) for the Mizzen and King’s Cove areas. The Mizzen prospect is located at about 500 km north-east of St. John’s in a water depth of over 1,000 metres.

In 2011, Corridor Resources Inc. submitted plans to drill an offshore exploration well off Cape Anquille (Old Harry field) sometime over the short- to medium-term (2012-2015) depending on regulatory approvals.

As it can be observed, there is a significant level of exploration interest in the offshore area around NL (as measured by the licenses).

Given the past success of producers in the area to turn exploration licenses into significant discoveries and subsequently into developing projects, it is expected that industry activity will continue strongly over the coming decades.

Discoveries made outside the traditional Jean d’Arc Basin and the main offshore area also mean that there are prospects beyond the traditional areas.

With that in mind, while the licenses are there, the fact is that exploration drilling in the area has decreased substantially over the last few decades and that situation presents issues and concerns in regards to the long-term sustainability (beyond Hebron’s development) of the oil and gas industry in NL as current production levels will inevitably continue to decline over time.\(^{63}\)

**Onshore**\(^{64}\)

Onshore activity in NL is centered around the Port au Port peninsula on the west coast of Newfoundland.

Wells were drilled in the Garden Hill South Field in 2008, where a staged development plan is proposed using horizontal wells. The project proponent is PDI Production Inc. A seismic program is planned for the Garden Hill North and Central Lead in order to identify the potential for future development in the area by the same company.


\(^{64}\) CNLOPB, Newfoundland and Labrador Department of Finance, Newfoundland and Labrador Department of Natural Resources, and Newfoundland and Labrador Oil & Gas Industries Association (NOIA) (see links above)
In 2010 and 2011, various other companies including Deer Lake Oil and Gas Inc., Investcan Energy Corporation, Leprechaun Resources, Nalcor Energy, and Vulcan Minerals Inc., have completed onshore exploration activities for onshore oil and gas in Newfoundland.

Given the infancy of the onshore industry in the province and the lack of information, this particular area will not be included in our analysis.

This concludes the overview of the petroleum industry across Eastern and Atlantic Canada. The following section will elaborate on the methodology used by CERI to generate both a production and an industry expenditures outlook for offshore projects. The subsequent chapters will discuss the economic impacts estimated using CERI’s I/O model.
Chapter 2 - Methodology

In order to be able to generate an outlook for production and capital expenditures, two models were developed by CERI for analyzing offshore Atlantic projects.

One model is the production model which was developed on a project-by-project basis for the projects included in our analysis, including offshore shallow water natural gas projects in Nova Scotia, and offshore crude oil projects in Newfoundland and Labrador (the offshore). The results of this model are an unconstrained production outlook for each project.

The second model is a project specific cash-flow (CF) model. This model serves the purpose of evaluating future development of a project based on economic considerations, as will be further explained below, and thus adjusts a project’s production outlook as needed.

The results from these models (oil and gas production volumes, as well as industry expenditures) are used as inputs or injections into CERI’s United States-Canada Multi-Regional Input/Output Model (UCMRIO 2.0), which in turn calculates the various economic impacts associated with the level of activity stemming from the outlook models over the 2010 to 2035 time period.

Thus, the results are the economic effects stemming from the industry’s continued activity in the offshore over the long-term and will be presented in Chapters 3 and 4.

Production Outlook
In order to generate a reliable production outlook for existing offshore projects, various data sources were reviewed including historical production numbers sourced from either the CNSOPB or the CNLOPB and cross-checked against CAPP’s Statistical Handbook, but also with the latest version of Statistics Canada’s Energy Statistics Handbook data, for a particular area (offshore Nova Scotia or Newfoundland and Labrador).

Data on original resources in place as well as recoverable volumes, together with cumulative production figures is also necessary. This data dictates the physical limits of the amount of

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66 The outlook period is 2010 to 2035. Historical data reviewed is from the point of initial production from each particular project to year-end 2009
67 CNSOPB: http://www.cnsopb.ns.ca/index.php (accessed on October 2, 2011)
resources that are extractable with current technology and under current economic conditions from each particular field or pool, and associated with each individual project.

This data was sourced mainly from the CNSOPB and the CNLOPB, but also cross-checked against estimates from the project proponents’ development plan applications (DPA), which are available through either of the offshore petroleum boards or the operators’ websites. Further, news reports were used to make appropriate adjustments to recoverable reserves estimates in the case of reserve write offs (or additions), as in the case for the SOEP (*Hibernia, White Rose*).

Understanding a particular project’s production design or maximum flow capacity is also important as it identifies the capability of a project to produce a certain rate of output, given its physical limitations. Statistical data analysis of production allows us to determine peak production levels from a particular project, field, or pool, as well as to establish a production decline curve, which is governed by a platform or project’s design capacity, and by the amount of remaining recoverable resources in a pool or field.

CERI recognizes that analyzing a project’s decline production pattern based solely on a statistical analysis of the historical production and bound by the project’s maximum design flow and remaining recoverable resources might lead to production projections which might not be realistic. Therefore, while an economically boundless production profile is developed for reference purposes, the project’s cash flow, or economic considerations, will also ultimately dictate the point at which the project will cease production. Thus, production from a particular project stops either at the point in which all recoverable resources are developed, or at the point where the project is no longer economically viable (uneconomic), whichever occurs first. This point is further discussed below.

In terms of a production outlook for projects not yet in operation or projects which are planned to be expanded, data from each project’s development plan was used to draw an outlook. In some cases, a project plan will outline exactly how the project is expected to produce over the project’s lifetime. Otherwise, CERI adopts the production profile of a similar project’s performance, consistent with design capabilities and recoverable resources.

Once an outlook for each project was generated (for both existing and new projects), the overall outlook for a particular area was compared with the most recent publicly available outlooks from other energy research and related organizations such as the National Energy Board (NEB) Energy Futures report, 71 and CAPP’s most recent analysis 72 in order to assess its

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72 CAPP, CAPP’s Canadian Crude Oil Forecast & Market Outlook: [http://www.capp.ca/forecast/Pages/default.aspx#CQsH6xPmBZLb](http://www.capp.ca/forecast/Pages/default.aspx#CQsH6xPmBZLb) (accessed on October 2, 2011)
validity and adjusted as necessary.\textsuperscript{73} The results were further discussed with expert sources in Atlantic Canada as part of CERI’s due diligence process.

Production outlooks for both Nova Scotia and Newfoundland and Labrador are discussed below.

**Offshore Shallow Water Nova Scotia – Natural Gas**

Offshore Nova Scotia gas production will consist of continued production from the *Sable Offshore Energy Project* (SOEP) and new production from the *Deep Panuke Project*, expected to start production in 2011.\textsuperscript{74}

Data used to establish a SOEP production outlook include estimated gas in place (GIP) as given by the operator’s original development plan application (DPA), estimated recoverable volumes of natural gas, cumulative production rates, production rates in the most recent year, and remaining recoverable resources are presented in Table 2.1 below. However, evidence of recoverable reserves revisions and write-offs, as stated on Page 19 of this report, were also taken into consideration.

The estimated gas in place and recoverable volumes were sourced from the operator’s (ExxonMobil) DPA, the document filed with the CNSOPB prior to development of the project. Production numbers were sourced from the CNSOPB and correspond to historical volumes produced from each field since start of production until year-end 2009. Based on this data, and taking into account recoverable reserve revisions, CERI estimates the remaining volumes of recoverable resources.

A maximum design production capacity (on a field by field basis) is estimated using the given design capacity in the operator’s DPA, or assuming that the highest (peak) production rate achieved historically corresponds to 90 percent of the maximum design or possible production capacity, whichever figure is higher. By doing this, CERI corrects for discrepancies that could occur in a situation where production levels from a particular field historically exceeded its originally proposed maximum design/flow capacity.

Based on production from the latest observation (2009), and given the remaining recoverable volumes at year-end 2009, the number of years of future production can be estimated by assuming a constant production rate in a given field over the remaining recoverable volumes, expressed by the reserves to production (R/P) ratio (number of years).

\textsuperscript{73} In the case for NL, two other production outlooks were used as well. One made available by the CNLOPB to the media, as well as one developed by Professor Wade Locke of Memorial University, available at: http://www.thetelegram.com/Economy/2010-04-10/article-1454562/A-shorrange-mountain-of-oil-production/1 (accessed on October 24, 2011) http://www.mun.ca/harriscentre/policy/memorialpresents/2011c/Wade_Locke_presentation.pdf (accessed on October 24, 2011)

\textsuperscript{74} CERI assumes production of the Deep Panuke project to begin at start of 2011 even though there has been no production from this project as of the time of writing.
Table 2.1: Sable Offshore Energy Project (SOEP) Data Used for Outlook

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<th>Field Name</th>
<th>Estimated Gas in Place (bcf) (Mean Probability)</th>
<th>Recoverable Volumes (bcf) (P50)</th>
<th>% Recoverable</th>
<th>Cumulative Production (Year-End 2009) (bcf)</th>
<th>Remaining Recoverable (Year-End 2009)</th>
<th>% Remaining Recoverable</th>
<th>2009 Production (bcf)</th>
<th>R/P</th>
<th>Maximum Design Production Capacity (bcf/yr)</th>
<th>Maximum Historical Production Level (bcf/yr)</th>
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<td>9</td>
<td>92</td>
<td>71</td>
<td>78%</td>
</tr>
<tr>
<td>North Triumph</td>
<td>540</td>
<td>323</td>
<td>60%</td>
<td>237</td>
<td>86</td>
<td>27%</td>
<td>12</td>
<td>7</td>
<td>56</td>
<td>50</td>
<td>90%</td>
</tr>
<tr>
<td>Alma</td>
<td>532</td>
<td>334</td>
<td>63%</td>
<td>281</td>
<td>53</td>
<td>16%</td>
<td>42</td>
<td>1</td>
<td>55</td>
<td>49</td>
<td>90%</td>
</tr>
<tr>
<td>South Venture</td>
<td>401</td>
<td>256</td>
<td>64%</td>
<td>211</td>
<td>44</td>
<td>17%</td>
<td>30</td>
<td>1</td>
<td>55</td>
<td>49</td>
<td>90%</td>
</tr>
<tr>
<td>Glenelg</td>
<td>440</td>
<td>259</td>
<td>59%</td>
<td>0</td>
<td>0</td>
<td>0%</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td>Total SOEP</td>
<td>4,589</td>
<td>2,644</td>
<td>58%</td>
<td>1,565</td>
<td>469</td>
<td>18%</td>
<td>127</td>
<td>9</td>
<td>387</td>
<td>194</td>
<td>50%</td>
</tr>
</tbody>
</table>

Note: Differences between recoverable volumes and cumulative production equal remaining recoverable volumes, except for the cases in which historical reserve revisions were made such as in the case of the Glenelg field which is included for illustration purposes only. Based on information collected by CERI, this field has been written off, will not be developed, and is thus not included in our analysis.

Source: CNSOPB data, ExxonMobil Sable Project data, analysis and table by CERI

Figure 2.1: Sable Offshore Energy Project Historical Production Profile

Source: CNSOPB data, ExxonMobil Sable Project data, analysis and figure by CERI

ExxonMobil Sable Project, Operations, Development Plan Application: [http://www.soep.com/cgi-bin/getpage?pageid=1/15/0](http://www.soep.com/cgi-bin/getpage?pageid=1/15/0) (accessed on October 2, 2011)

However, this number is not definitive as production levels decline with resource depletion and loss of reservoir pressure. This in turn translates into an extended life for the project, subject to resource availability constraints, indicating that the remaining life of the project is at least that of the obtained R/P ratio or longer (shorter) in the case of reserve additions (revisions)(upside and downside risks).  

With that in mind, CERI estimates a production profile given by the production rate in a given year as a percentage of the calculated maximum design production capacity (proposed maximum flow capacity or highest achieved). This is presented in Figure 2.1.

This figure illustrates the performance of a field in a given year and allows for determination of a peak production rate where the reservoir pressure starts to drop and continued resource extraction results in naturally declining levels (depletion) over time.

This profile is then used to determine a compound annual decline rate (CADR) given by the year in which peak production rates were reached (historically) and the latest observation period (2009). This rate is used to estimate the production profile for the outlook period or the decline curve.

Figure 2.2: Historical and Outlook Production Profiles (%), left scale) and Remaining Recoverable Natural Gas Volumes [bcf], right scale), by Field (SOEP) – Reserve Unadjusted and Cash Flow Unconstrained

Source: CNSOPB data, ExxonMobil Sable Project data, analysis and figure by CERI

On the other hand, project economics also pose both downside and upside risks on the project’s expected life and outlook as costs tend to increase over time and might lead to earlier than expected shutdown (downside risks) while improvement in technology can play a role in recovery efficiency thus increasing the project’s life (upside risks).
The production outlook is then dictated by an extension of the production profile based on historical natural declines/performance (as given by Figure 2.1), limited by a maximum design production capacity, and last but not least, by the amount of remaining recoverable resources in a field. The results of this analysis are shown in Figure 2.2.

Note that Figure 2.2 presents an outlook which is both reserve-unadjusted and economically unconstrained (since it does not take into consideration the cash flow of the project), and it is presented for illustrative purposes only.

In regards to Figures 2.1 and 2.2, it is important to keep in mind that year 1 refers to the year for which production from a particular field commenced (e.g., Thebaud, 1999; Venture and North Triumph, 2000; Alma, 2003, and South Venture, 2004), while year 0 is used in relation to the recoverable natural gas volumes. Hence, 0 corresponds to the initial recoverable estimates (before any production occurred).

The next step is to evaluate the project on its economic basis by doing a cash flow analysis (discussed below), but also adjusting the outlook to reflect historical recoverable reserve adjustments (write downs or additions), which in turn means a revision to the outlook for both production profiles and recoverable volumes originally given in Figure 2.2, as seen in Figure 2.3.

**Figure 2.3: Historical and Outlook Production Profiles (% left scale) and Remaining Recoverable Natural Gas Volumes [bcf], right scale), by Field (SOEP) – Reserve Adjusted and Cash Flow Constrained**

Source: CNSOPB data, ExxonMobil Sable Project data, analysis and figure by CERI
Given these parameters, a production outlook is estimated for the SOEP for the 2010 to 2035 time period. This outlook is presented in Figure 2.4.

**Figure 2.4: Sable Offshore Energy Project, Historical (1999-2009) and Outlook (2010-2035)**

*Natural Gas Production Levels, by Field*

Source: CNSOPB data, ExxonMobil Sable Project data, outlook analysis and figure by CERI

**Figure 2.5: Deep Panuke Marketable Natural Gas Production (MMcf/d), 2011-2026 Outlook**

Source: EnCana data, analysis and figure by CERI

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Based on CERI’s analysis, the SOEP project will continue to produce natural gas over the medium- to long-term. Over the next half decade, the remaining recoverable resources from the Thebaud, Alma, and South Venture fields will be produced.

Given the significant amount of recoverable volumes remaining in the Venture field and the production profile outlook, this field would be the main producer from the SOEP project past 2015, with lesser production volumes coming from the North Triumph field as well.

CERI’s economic analysis of the SOEP indicates that by 2017 revenues generated by the project (including natural gas liquids revenues) are just enough to cover the project’s operating costs and thus the project becomes uneconomic (see discussion below). At this point, the SOEP production is assumed to stop.

The Glenelg field was not included in CERI’s analysis as the field’s reserves were written down as part of major reserve revisions in 2004 by the project partners. No further drilling is assumed to occur in relation to the project and no other fields are assumed to be developed.

It is worth noting that the outlook for the SOEP (and all other evaluated projects) is unique to CERI’s assumptions in terms of costs, inflation, prices, and other inputs used in CERI’s models (as discussed below).

While CERI clearly understands that the end results are highly sensitive to the inputs used, CERI strives to develop the most appropriate inputs by reviewing assumptions and modeling processes both internally as well as in discussion with industry and other energy research organizations. These results are thus based on CERI’s views and do not represent a definitive and exclusive pathway of development for the offshore petroleum industry in Atlantic Canada, and are thus also subject to both upside and downside risks as discussed.

A Deep Panuke project production forecast was obtained directly from EnCana’s Deep Panuke Development Plan. The P50 (50 percent or average probability, similar to the mean probability) sales gas forecast was used. This production forecast is presented in Figure 2.5.

Deep Panuke’s production profile calls for total production of 679 bcf, with a peak production rate of 300 MMcf/d over the second and third years of production, and an average of 124 MMcf/d over the project’s expected 15 years of production.

Figure 2.6 illustrates the total natural gas production outlook for offshore Nova Scotia given by the SOEP and Deep Panuke projects as estimated by CERI.

CERI’s outlook for offshore natural gas production for the 2010 to 2035 time period yields cumulative production volumes of over 1 tcf (1,033 bcf). Over the initial years of the outlook period (2010-2013), production from the Deep Panuke project will contribute to an overall increase compared to 2009 levels, with offshore natural gas production levels averaging 384 MMcf/d. Starting in 2014, production will be below the 2009 rate as natural declines in the Deep Panuke project add to the down trend in production from the SOEP.
Figure 2.6: Offshore Nova Scotia Natural Gas Historical (1999-2009) and Outlook (2010-2035) Production (MMcf/d), by Project

Note: NEB numbers are taken from the Energy Futures Report, 2009 Reference Case Scenario, for which the latest actual data year is 2008. The NEB projections are for the 2009 to 2020 time period and extrapolated by CERI to 2035 using a compound annual decline rate (CADR) calculated for the 2016-2020 (5 year) time period. The NEB forecast assumes much more rapid declines in volumes from the SOEP project, offset somewhat by production from the Deep Panuke project, which was assumed to start production in 2010.

Source: CNSOPB data, EnCana data, ExxonMobil Sable Project data, NEB data, outlook analysis and figure by CERI

From 2015 until 2020, production averages 131 MMcf/d on an annual basis. By 2017, the SOEP is assumed to stop production, while production levels from the Deep Panuke project are expected to average 41 MMcf/d annually over the 2020 to 2025 time period. By 2026, production from the Deep Panuke project is assumed to stop, and since production from the SOEP is assumed to stop earlier, no further production is in the outlook for the 2026 to 2035 time period.

Offshore Newfoundland and Labrador – Crude Oil
The same process (and due diligence) described and explained above was used to generate a production outlook for NL offshore crude oil projects. Historical production data from individual projects provided by the CNLOPB was analyzed to establish production profiles for each project.

Project development plans’ production forecasts were used where appropriate/available. Meanwhile, decline curves limited by estimated remaining recoverable resources (Proven + Probable: 2P) by fields, pools, and reservoirs, together with their maximum production/
extraction capacity, combined with the project’s cash flow analysis (economics) were used where production forecasts were not available in order to establish an outlook for production and investments.

Figure 2.7 illustrates CERI’s outlook for offshore crude oil production in Newfoundland and Labrador as well as a comparison with the most recent publicly available forecasts for the region.

CERI’s outlook for offshore crude oil production for the 2010 to 2035 time period yields cumulative production volumes of over 1.7 Bb (1,720 MMb). Over the initial years of the outlook period (2010-2016) production from the existing projects (including extensions at *Hibernia* and *White Rose*) exhibit an overall declining trend, after a peak is reached at 280 Mb/d in 2011 when production from new blocks in *Hibernia* and the North Amethyst field (*White Rose* project) ramps up to the maximum capacity flow.

Over the same time period, production rates average 244 Mb/d on an annual basis (or slightly below 2009 levels). By 2017, production from the *Hebron* project reverses the trend and by 2019, offshore crude oil production levels are expected to reach 246 Mb/d. From 2017 to 2020 production rates average 230 Mb/d. Over the remainder of the outlook period (2021 to 2035), natural declines from all projects push production into a decline trend which yields an annual average of 139 Mb/d.

**Figure 2.7: Offshore Newfoundland and Labrador Crude Oil Historical (1997-2009) and Outlook (2010-2035) Production (Mb/d), by Project**

Sources: CAPP data,\(^78\) CNLOPB data,\(^79\) Memorial University data, NEB Data, outlook analysis and figure by CERI

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\(^78\) Similar to the case with the NEB projections, CAPP projections are given for the 2011 to 2025 time period, extrapolated to 2035 by CERI
By 2035, production is expected to be about 50 Mb/d, most of it (84 percent) from the Hebron project, which is expected to cease production by 2046. The only other source of production in 2035 is Hibernia, scheduled to cease production in the following year. CERI expects Terra Nova to cease production by 2020 and White Rose in the late 2020s, close to 2030.

**Cash Flow Models and Industry Expenditures Outlook**

In order to generate cash flow (CF) models for individual projects, various sources of information are required. This information is divided into two broad categories, project expenditures and project revenues.

Project expenditures are further divided into other sub-categories including exploration expenditures and pre-development expenditures, development expenditures, and operating expenditures, but also include royalties payable to the government (as a share of the value of the extracted and marketed resource) from each individual offshore project.

Revenues for each project are derived from production rates and commodity prices, whether it is natural gas and natural gas liquids (NGLs) in the case for Nova Scotia’s offshore projects, or crude oil in Newfoundland and Labrador’s case. Historical expenditures information (including royalties) for a particular offshore region is available from various sources including CAPP’s Statistical Handbook and the respective offshore petroleum boards.

**Offshore Nova Scotia**

In Nova Scotia, the CNOSPB’s annual reports 80 are a good source of information regarding individual project’s industrial benefits 81 including annual project expenditures, cumulative project expenditures, project-related employment, 82 as well as royalties paid by project. Benefit reports are filed by the project operator’s on an annual or quarterly basis, as required by the CNSOPB.

A recent report prepared for the Nova Scotia Department of Energy by Stantec Consulting Ltd., which addresses some of the economic benefits associated with the development and

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79 All project development applications are available at: CNLOPB, Information & Reports, Decision Reports: http://www.cnlopb.nl.ca/news/decisions.shtml (accessed on October 2, 2011)
80 CNSOPB, About Us, Annual Reports: http://www.cnsopb.ns.ca/annual_report.php
81 For more on industrial benefits and benefits plans see: CNSOPB, CA-NS Benefits, Benefits Plans: http://www.cnsopb.ns.ca/benefits_plans.php (accessed on October 2, 2011)
82 While employment numbers are not relevant to this part of our analysis, historical employment numbers are important when comparing actual employment numbers in a region with the results obtained on economic benefits through CERI’s Input/Output model and presented in Chapters 3 and 4 of this report

November 2011
operations of Nova Scotia’s offshore natural gas projects, was also a useful source for project expenditures data.⁸³

Analyzing the historical expenditures data from all sources (CAPP, CNSOPB, Stantec) together with the researched information gathered on costs (obtained primarily from project development plans) for individual projects in Nova Scotia (as presented in Chapter 1), CERI’s analysis establishes relationships regarding exploration, pre-development, development and operating expenditures and allocates costs on a project by project basis, historically.

This data is then summed and compared to actual historical numbers for Nova Scotia, as presented in Figure 2.8, which validates the soundness of CERI’s estimates for the purpose of building offshore Nova Scotia projects’ CF models.

This information allows for the allocation of a specific type of expenditure at a particular point in time, given historical developments, and allows to draw relationships that determine unit costs of production (variable operating costs) or $/mcf of operating costs for the SOEP, as well as fixed annual operating costs ($ millions per year), which are then directly linked to the production outlook.

Deep Panuke Project’s cost figures were obtained from the project’s development plan and adjusted as needed for the outlook period.

Figure 2.8: Offshore Nova Scotia Projects Historical, Annual (Left Scale) and Cumulative (Right Scale) Expenditures (Millions of $ Nominal), 1995-2009

Source: CAPP data, CNSOPB data, Stantec/Nova Scotia Department of Energy study data, analysis and figure by CERI

Based on this information, and taken together with an unconstrained production outlook, a cash flow analysis is carried out given by (simplified representation):

\[ TR - TC = ATFCF, \text{ where:} \]

\[ TR = \text{Total Revenue} \]

\[ TC = \text{Total Costs}; \text{ and} \]

\[ ATFCF = \text{After} - \text{Tax Free Cash Flow}; \text{ and where:} \]

\[ TR = \text{Revenue from sales of hydrocarbons (gas and natural gas liquids or crude oil)} \]

\[ TC = CC + OC + R + T + I, \text{ where:} \]

\[ CC = \text{Capital costs including exploration, development, and abandonment costs} \]

\[ OC = \text{Fixed operating costs + variable operating costs + transportation costs} \]

\[ R = \text{Applicable Royalties} \]

\[ T = \text{Applicable Taxes} \]

\[ I = \text{Appropriate Return on Investment} \]

The equations give a simplified representation of the cash flow analysis, while Figure 2.9 is a graphical presentation of the CF analysis for a given project.

Also, comparison of historical collected royalty revenues with CERI’s obtained results further validates the data, as royalties take into account the interaction of various revenue and costs items.

The cash flow analysis limits the unconstrained production outlook by determining where a project is bound to stop production, given by the point in time in which the project’s total revenues are equal to the total cash costs (capital + operating costs), as the net revenues from the project at such point in time will be equal to 0. At such point in time, any applicable royalties and taxes payable will be in excess of the cash costs, which will in fact represent a loss to the producer, and there effectively will no longer be an increased return on investment.

While it is understood that a situation characterized by negative net revenues in a single year might not necessarily be conducive to an overall loss over the life of the project (for example, at the start of the project), this situation is likely to persist toward the end of the project cycle as revenues decline based on declining production and cost inflation continues to occur.

Figure 2.10 illustrates the results of CERI’s outlook for expenditures in offshore natural gas projects in Nova Scotia. These numbers, driven by the production outlook, and taken together with the production outlook, constitute the inputs required for CERI’s I/O model in order to estimate the economic benefits presented in Chapter 3 of this report.
Figure 2.9: SOEP Cash Flow Analysis, Historical (1999-2009) and Outlook (2010-2018) (Millions of $ Nominal) (Left Scale), and SOEP Production (MMcf/d) (Right Scale)

Source: CNSOPB data, ExxonMobil Sable Project data, outlook analysis and figure by CERI

Figure 2.10: Offshore Nova Scotia Projects Historical (1994-2009) and Outlook (2010-2035) Expenditures (Millions of $ 2010), by Project

Note: Historical expenditure data from this figure might not necessarily reflect the deflated values given in Figure 2.8, as for the purpose of the CF analysis drilling and other pre-development expenditures were allocated to the year prior to which the first development (construction and infrastructure) expenditures were incurred for existing projects. This simply represents an adjustment for CF analysis purposes and it does not alter the historical CF results as these are highly related to the stream of generated revenues which depend on production levels, which are in turn taken as actual historical data on a cumulative basis. Equally, this adjustment does not affect the capital or operating expenditures layouts over the outlook period.

Source: CAPP data, CNSOPB data, Stantec/Nova Scotia Department of Energy study data, outlook analysis and figure by CERI

November 2011
Offshore Newfoundland and Labrador

In the case of Newfoundland and Labrador, specific benefits data (expenditures and employment data) on a project by project basis are available for 2007 and 2008 from the CNSOPB.\(^84\)

Meanwhile, historical expenditures data related to all offshore project’s, including exploration expenditures by region, pre-development expenditures, development expenditures, and production (operating) expenditures, is available from 1966 to 2009, also through the CNLOPB.\(^85\)

Information regarding royalties collected from offshore projects in Newfoundland and Labrador was collected from the province’s historical public accounts.\(^86\)

Figure 2.11: Offshore Newfoundland and Labrador Projects Historical, Annual (Left Scale) and Cumulative (Right Scale) Expenditures (Millions of $ Nominal), 1994-2009

Source: CAPP data, CNLOPB data, analysis and figure by CERI

In a similar process to that used for projects in Nova Scotia, CERI estimates historical expenditures on a project by project basis allocating available data and cross-checking with various data sources. Figure 2.11 illustrates the historical level of expenditures for all offshore projects in Newfoundland and Labrador developed by CERI, as well as a comparison with data from the CNLOPB and CAPP.

\(^{84}\)CNLOPB, Industrial Benefits, Project Benefits: [http://www.cnlopb.nl.ca/ib_project.shtml](http://www.cnlopb.nl.ca/ib_project.shtml) (accessed on October 2, 2011)


November 2011
Figure 2.12: Offshore Newfoundland and Labrador Projects Historical (1990-2009) and Outlook (2010-2035) Expenditures (Millions of $ 2010), by Project

Note: As in the case for NS, historical expenditure data from this figure might not necessarily reflect the deflated values as given in Figure 2.11, as for the purpose of the CF analysis, drilling and other pre-development expenditures were allocated to the year prior to which the first development (construction and infrastructure) expenditures were incurred for existing projects. This simply represents an adjustment for CF analysis purposes and it does not alter the historical CF results as these are highly related to the stream of generated revenues which depend on production levels, which are in turn taken as actual historical data. Equally, this adjustment does not affect the capital or operating expenditures layouts over the outlook period.

Source: CAPP data, CNLOPB data, outlook analysis and figure by CERI

The information obtained from the historical data distribution on a project by project basis allows for the provision of unit operating costs ($/b), as well as fixed operating costs ($ millions per year), which allows for determining future operating expenditures for existing projects.

On the other hand, information for upcoming projects or existing project expansions is also included in the outlook, and it is presented in Figure 2.12. This figure illustrates the results of CERI’s outlook for expenditures in offshore crude oil projects in Newfoundland and Labrador.

These numbers, driven by the production outlook, and taken together with the production outlook, constitute the inputs required for CERI’s I/O model in order to estimate the economic benefits presented in Chapter 4 of this report.

Other Cash Flow Items
Information on each province’s royalty regime was reviewed as needed since one of the main objectives of the CF model is to estimate an outlook for royalty revenues on a project by projects basis, and on an overall provincial basis. This information is available from the Nova
Overview of Eastern and Atlantic Canada’s Petroleum Industry and Economic Impacts of Offshore Atlantic Projects (2010-2035)

Scotia Department of Energy,\textsuperscript{87} and the Newfoundland and Labrador Department of Natural Resources.\textsuperscript{88} Further, literature was reviewed to gain a more thorough understanding of the respective royalty regimes.\textsuperscript{89}

An economic model developed for the Nova Scotia Department of Energy\textsuperscript{90} was reviewed with the purpose of having a more in-depth and detailed idea of the process needed to calculate royalties. While this model applies to NS projects in particular, the NL royalty regime is somewhat similar (yet varies by project),\textsuperscript{91} and therefore has some applicability in this context as well.

Historical pricing information for North American commodity benchmarks such as Henry Hub (HH) prices for natural gas and West Texas Intermediate (WTI) for light sweet crude oil, are a good starting point for pricing information, and are available both from CAPP’s Statistical Handbook as well as from the United States Department of Energy’s (DOE) statistical and analysis agency, the Energy Information Administration (EIA).\textsuperscript{92}

For the outlook period, forecast prices for both Henry Hub and WTI from the EIA’s latest Annual Energy Outlook (2010-2035) are used.\textsuperscript{93} These are illustrated in Figure 2.13.

Historical natural gas pricing data from both the EIA as well as the NEB, together with pipeline tolls information for the M&NP\textsuperscript{94} as well as historical trade flow data was further used and analyzed to understand pricing dynamics and relationships between natural gas produced offshore Nova Scotia and Henry Hub prices.

This allows CERI to estimate the price historically and the expected price (given a forecast price for HH) in the outlook period for offshore Nova Scotia’s natural gas, and given as a HH price ratio, used over the outlook period.

\textsuperscript{88} Newfoundland and Labrador Department of Natural Resources, Royalties and Benefits, Oil & Gas: \url{http://www.nr.gov.nl.ca/nr/royalties/oil_gas.html} (accessed on October 2, 2011)
\textsuperscript{89} Atlantic Petroleum Royalties: Fair Deal or Raw Deal?, G.C Watkins, Atlantic Institute for Market Studies, June 2001: \url{http://www.aims.ca/site/media/aims/royalties.pdf} (accessed on November 2, 2011)
\textsuperscript{90} Taxing Canada’s Cash Cow: Tax and Oil Royalty Burdens on Oil and Gas Investments, Jack Mintz and Duanjie Chen, The School of Public Policy, University of Calgary: \url{http://www.policyschool.ucalgary.ca/files/publicpolicy/mintz3.pdf} (accessed on November 2, 2011)
\textsuperscript{91} CERI is currently working on an overview of oil and gas royalty regimes across Canada, while also developing an outlook for royalty revenues for the 2010 to 2035 time period. Once completed, the report will be available at \url{www.ceri.ca}
\textsuperscript{92} Energy Information Administration, EIA: \url{http://www.eia.gov/} (accessed on October 2, 2011)
\textsuperscript{93} Energy Information Administration, Analysis & Projections, Annual Energy Outlook \url{http://www.eia.gov/forecasts/aeo/} (accessed on October 2, 2011)
\textsuperscript{94} Maritimes & North Pipeline: \url{http://www.mnpp.com/} (accessed on October 2, 2011)
Figure 2.13: Commodity Price Forecast ($ Nominal), 2010-2035

Source: EIA data, figure by CERI

Historical crude oil pricing data from the EIA and CAPP, as well as crude oil trade statistics from Statistics Canada, and crude oil pipeline tolls information presented in CAPP’s latest crude oil forecast were used and analyzed to determine pricing relationships between WTI and prices for Newfoundland’s crude oil from offshore projects. In a similar fashion to that of natural gas prices, Newfoundland’s crude oil price is given by a ratio to WTI, used over the outlook period.95

Finally, given that most of the historical data collected is given in nominal (or money of the day) dollars, data on Canada’s gross domestic product (GDP) both at current and constant (real) prices was collected from the World Bank96 in order to be able to understand the industry’s expenditures in a particular region, in 2010 real terms (using GDP deflators).

Canadian/US foreign exchange rates (XR) were used to convert pricing information to Canadian dollars and analyzed to create a foreign exchange rate assumption for the outlook period (parity), while Consumer Price Index (CPI) data was collected and analyzed with the same purpose but with regards to inflation levels.

This information is necessary, as the CF models are developed on a nominal basis (both historically and for the outlook period) or not adjusted for inflation, while the results presented across this report are (unless otherwise specified) given in 2010 real dollar terms, for consistency (adjusted for inflation). CPI estimates are also necessary in order to estimate royalty components for certain projects.

95 While CERI acknowledges that the benchmark for oil prices in Atlantic Canada and the North-eastern United States is closer to North Sea (Brent) prices than West Texas Intermediate prices and that while the differential between Brent and WTI has widened substantially over the last year, it is questionable to assume that this situation will persist over the long term. For that reason, CERI uses a WTI price adjusted with a ratio as determined by CERI’s analysis on pricing dynamics in the region

96 The World Bank, Data, Canada: http://data.worldbank.org/country/canada (accessed on October 2, 2011)
Long-term bond rates data (LTBRs) or data on yields for long-term Government of Canada bonds was also analyzed to create an outlook for this item as required for some royalty calculations. Exchange rate, CPI, and LTBRs data was collected both from Statistics Canada and the Bank of Canada.

Figure 2.14 illustrates the assumptions regarding exchange rates, inflation, and long-term bond rates over the forecast period for the CF models purposes.

Figure 2.14: CAD/US Exchange Rate (Left Scale), Inflation Index (Left Scale), and Long-Term Bond Rate (Right Scale) Outlook, 2010-2035

Source: CERI

Further Due Diligence

Last but not least, economic data such as GDP, employment, and population, on a provincial and on an industry and sector basis (where applicable) was collected from the respective offshore petroleum boards, the Nova Scotia Department of Finance’s Economic and Statistics division, the Newfoundland and Labrador’s Department of Finance Economic Research and Analysis division, as well as Statistics Canada.

This data was used to compare and validate the results obtained and presented in Chapters 3 and 4 of this report.

This concludes the discussion of the production outlook and cash-flow models methodology. The following chapters will discuss the economic impacts across North America, associated with offshore projects both in Nova Scotia (Chapter 3) and Newfoundland and Labrador (Chapter 4), obtained using CERI’s Input/Output model.
Chapter 3 – Economic Impacts of Offshore Shallow Water Natural Gas Projects in Nova Scotia

This chapter details the economic impacts of offshore shallow water natural gas developments (including the Sable Offshore Energy Project [SOEP]), and the Deep Panuke project) in Nova Scotia and the associated impacts on the North American economies.

Impacts are calculated both for Canada and the United States, with Canadian impacts broken down to the provincial level, and US impacts both at the Petroleum Administration for Defense District (PADD)\(^1\) and state levels.\(^2\)

Economic impacts under consideration include economy-wide impacts such as value-added gross domestic product (GDP), employee compensation (including wages and supplements), jobs created and preserved (given in thousands of person-years, one person year being one person working for one year), as well as various forms of government revenues including indirect, personal, and corporate taxation revenues, but also royalty revenues from resource extraction and development.

These impacts cover all offshore industry activities including geological, geophysical, drilling, completion, tie-in, and infrastructure development associated with new projects, as well as operating activities related to existing projects as identified in the previous chapters.

**Canadian Impacts**

Total investment expenditures from the offshore natural gas industry in Nova Scotia over the outlook period (2010-2035) will amount to close to $4 billion ($3,821 million), including over $400 million in capital expenditures and close to $3.4 billion ($3,397 million) in operating expenditures.

The cumulative sum of additional GDP from 2010 to 2035 as a result of continued operations of the SOEP project and the addition of the Deep Panuke project is estimated at close to $5.3 billion (see Table 3.1). Close to 94 percent of the GDP impact is expected to occur in the province of Nova Scotia, close to 4 percent in Ontario, and the remaining 3 percent across the rest of Canada.

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1 For more on PADDs see: Energy Information Administration (EIA), Petroleum & Other Liquids, PADD Definitions: [http://205.254.135.24/oog/info/twip/padddef.html](http://205.254.135.24/oog/info/twip/padddef.html) (accessed on October 1, 2011)

2 As previously stated, all $ figures are given in real 2010 dollars unless otherwise specified and Canadian dollar/USD parity is assumed
Cumulative employee compensation over the outlook period is expected to be close to $1.2 billion, with 85 percent of the impact in Nova Scotia, 11 percent in Ontario, close to 3 percent in Quebec, and the remaining 1 percent across the rest of Canada.

Table 3.1: Economic Impacts (Millions of $ 2010 and Thousand Person Years) of Nova Scotia’s Offshore Shallow Water Natural Gas Projects in Canada, by Province, 2010-2035

<table>
<thead>
<tr>
<th>Investments and Operations</th>
<th>$CAD Million</th>
<th>Thousand Person Years</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>GDP</td>
<td>Compensation of Employees</td>
</tr>
<tr>
<td>Alberta</td>
<td>14</td>
<td>8</td>
</tr>
<tr>
<td>British Columbia</td>
<td>15</td>
<td>9</td>
</tr>
<tr>
<td>Manitoba</td>
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</tr>
<tr>
<td>New Brunswick</td>
<td>30</td>
<td>16</td>
</tr>
<tr>
<td>Newfoundland &amp; Labrador</td>
<td>5</td>
<td>2</td>
</tr>
<tr>
<td>Northwest Territories</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nova Scotia</td>
<td>4,939</td>
<td>985</td>
</tr>
<tr>
<td>Nunavut</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Ontario</td>
<td>190</td>
<td>106</td>
</tr>
<tr>
<td>Prince Edward Island</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>Quebec</td>
<td>56</td>
<td>33</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>2</td>
<td>1</td>
</tr>
<tr>
<td>Yukon Territory</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total Canada</strong></td>
<td><strong>5,256</strong></td>
<td><strong>1,162</strong></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Thousand Person Years</th>
<th>Direct</th>
<th>Indirect</th>
<th>Induced</th>
<th>Sum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta</td>
<td>0.0</td>
<td>0.1</td>
<td>0.1</td>
<td>0.2</td>
</tr>
<tr>
<td>British Columbia</td>
<td>0.0</td>
<td>0.1</td>
<td>0.2</td>
<td>0.2</td>
</tr>
<tr>
<td>Manitoba</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.1</td>
</tr>
<tr>
<td>New Brunswick</td>
<td>0.0</td>
<td>0.2</td>
<td>0.2</td>
<td>0.5</td>
</tr>
<tr>
<td>Newfoundland &amp; Labrador</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.1</td>
</tr>
<tr>
<td>Northwest Territories</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Nova Scotia</td>
<td>5.6</td>
<td>6.2</td>
<td>8.3</td>
<td>20.1</td>
</tr>
<tr>
<td>Nunavut</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Ontario</td>
<td>0.0</td>
<td>1.0</td>
<td>1.6</td>
<td>2.6</td>
</tr>
<tr>
<td>Prince Edward Island</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.1</td>
</tr>
<tr>
<td>Quebec</td>
<td>0.0</td>
<td>0.4</td>
<td>0.6</td>
<td>0.9</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Yukon Territory</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

Source: CERI

The high proportion of the economic effects associated with Nova Scotia reflects on the importance of various local industries and their relationship with the offshore petroleum industry.

November 2011
Meanwhile, the distribution of the economic effects within Nova Scotia, across industries, will be associated with the sectorial/industrial make-up of the province, with large effects allocated to industries such as the finance, insurance, and company management industry, as well as the manufacturing and public administration industry (some of Nova Scotia’s largest industries by GDP), but also to industries which are closely linked to the offshore petroleum industry such as the transportation and marine services industries.

The economic effects observed in other regions of the country (indirect plus induced), are a reflection of the different industrial/sectorial make-up across provinces and their dealings with local industries in Nova Scotia that are impacted by offshore petroleum development.

The same applies in the case for economic effects in regions across the United States, whether at the PADD or state level (discussed below).

The cumulative number of jobs created and preserved over the outlook period will amount to 25,000 jobs, with 80 percent of the overall impact expected in Nova Scotia, 12 percent in Ontario, and the remaining 8 percent across the rest of Canada.

Direct employment effects are attributed to Nova Scotia in its entirety and are related to those people that work directly for the offshore projects whether onshore (support) or offshore (operations).

Meanwhile, in regards to indirect and induced employment impacts Nova Scotia will benefit from 78 percent of indirect jobs created and preserved, and 75 percent of the induced number of jobs created and preserved across Canada as a result of activity in Nova Scotia’s offshore.

Indirect and induced jobs are defined as those associated with the industries that provide goods and services for the offshore petroleum industry (indirect), such as consulting and engineering firms, insurance and finance, transportation, ship manufacturing and marine services, government departments/agencies, as well as those jobs that are created in other industries due to the level of economic activity that is generated from the offshore petroleum industry’s activity, such as jobs in wholesale and retail trade, education, or medical services (induced).

Figure 3.1 depicts the pattern of employment creation and preservation in Canada as a result of industry activity in Nova Scotia’s offshore. The employment level increases and peaks (at close to 4,000 jobs in total, and close to 1,000 direct jobs) over the second observation year in the outlook period (2011) as the Deep Panuke project is expected to commence operation. After that point, the level of employment decreases gradually, that is, no jobs are created and a portion of jobs are preserved, as natural declines from the fields in both projects bring production levels lower and lower.

---

By 2025, the Deep Panuke project is expected to be decommissioned while the SOEP is assumed to have stopped producing by 2017 as discussed in Chapter 2. After 2025 and until the end of the outlook period, employment levels related to the offshore petroleum industry are at 0. Economic effects of the offshore petroleum industry in the region follow the same pattern.

At this point, it is important to reiterate that these estimates do not include employment (or other associated economic benefits) related to companies that will potentially be conducting exploration and possibly development and production activities in the area, and only include the effects of the SOEP and Deep Panuke projects based on CERI’s assumptions (which are subject to both upside and downside risks as discussed).

Various challenges will affect future activity in the region over the medium to long term (and beyond the two analyzed projects) including but not limited to future natural gas prices, exploration and drilling costs, advancements in technology, and other factors that will affect the future prospects in the region.

Meanwhile, the PFA the government of Nova Scotia has recently conducted and made available to the public indicate that there is significant potential for hydrocarbon resources in offshore areas. Thus, companies interested in the area are bound to consider the opportunities and advantages associated with the existence of the current infrastructure around the Sable Island area including the production platforms, processing facilities, undersea pipelines to Goldboro as well as the existence of the onshore processing and fractionation plants, but also the connection to the M&NP, which means readily accessible connection to markets in Atlantic Canada and the north-eastern United States.
Table 3.2 illustrates the estimated cumulative taxation revenues that are expected to be collected across Canada over the outlook period, as a result of Nova Scotia’s offshore projects. These include over $632 million in indirect taxes (such as GST, PST, and HST) across Canada (92 percent collected in Nova Scotia), as well as over $648 million in personal income taxes across Canada (94 percent in Nova Scotia), and over $164 million in corporate taxes across Canada (92 percent in Nova Scotia).

This adds to a total of just over $1,444 million in government tax revenues across Canada at all levels of government (including municipal, provincial, and federal) with an estimated 93 percent to be collected in Nova Scotia.

Table 3.2: Government Taxation Revenues (Millions of $ 2010), by Province, 2010-2035

<table>
<thead>
<tr>
<th>Province</th>
<th>Indirect Tax</th>
<th>Personal Income Tax</th>
<th>Corporate Tax</th>
<th>Sum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta</td>
<td>1</td>
<td>1</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>British Columbia</td>
<td>2</td>
<td>2</td>
<td>0</td>
<td>4</td>
</tr>
<tr>
<td>Manitoba</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>New Brunswick</td>
<td>4</td>
<td>3</td>
<td>1</td>
<td>8</td>
</tr>
<tr>
<td>Newfoundland &amp; Labrador</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Northwest Territories</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Nova Scotia</td>
<td>581</td>
<td>611</td>
<td>151</td>
<td>1,343</td>
</tr>
<tr>
<td>Nunavut</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Ontario</td>
<td>32</td>
<td>23</td>
<td>9</td>
<td>64</td>
</tr>
<tr>
<td>Prince Edward Island</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Quebec</td>
<td>10</td>
<td>8</td>
<td>2</td>
<td>20</td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>Yukon Territory</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

Source: CERI

Figure 3.2: Royalty Revenues, by Project (Millions of $ 2010), 2010 – 2035

Source: CNSOPB historical data, historical/outlook analysis and data by CERI
Another source of government revenues is royalty revenues. CERI estimates (Figure 3.2) that over $729 million will be paid in royalties from offshore Nova Scotia’s projects over the outlook period. These include over $554 million paid from continued production of the SOEP, as well as close to $180 million in royalties paid over the life of the Deep Panuke project.

**US Impacts**

In regards to economic impacts from offshore Nova Scotia projects across the United States (US), CERI estimates that $330 million in value added (GDP) are expected to be generated over the outlook period, with the largest portion of the impacts (50 percent) expected to be allocated to PADD I (East Coast) or the main market for offshore Nova Scotia gas (connected through the M&NP infrastructure); followed by (20 percent) PADD II (Midwest), a large petrochemical and refining area; and (16 percent) PADD V (West Coast), a significant economic region in the US.

**Table 3.3: Economic Impacts (Millions of $ 2010 and Thousand Person Years) of Nova Scotia’s Offshore Shallow Water Natural Gas Projects in the United States, by PADD, 2010-2035**

<table>
<thead>
<tr>
<th>2010-2035</th>
<th>$CAD Million</th>
<th>Thousand Person Years</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>GDP</td>
<td>Compensation of Employees</td>
</tr>
<tr>
<td>PADD I</td>
<td>165</td>
<td>86</td>
</tr>
<tr>
<td>PADD II</td>
<td>68</td>
<td>36</td>
</tr>
<tr>
<td>PADD III</td>
<td>36</td>
<td>15</td>
</tr>
<tr>
<td>PADD IV</td>
<td>9</td>
<td>4</td>
</tr>
<tr>
<td>PADD V</td>
<td>54</td>
<td>26</td>
</tr>
<tr>
<td>Total US</td>
<td>330</td>
<td>167</td>
</tr>
</tbody>
</table>

Source: CERI

Over $167 million in employee compensation are expected to be generated from Nova Scotia’s offshore projects across the United States, with PADDs I, II, and V being the recipients of most of those benefits over the outlook period.

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4 For more on the Atlantic Canada and North-eastern US natural gas markets, while the following publications are somewhat outdated, they provide useful background information:
CERI, Study no. 97, Analysis of Basis at Eastern Hubs and the Impact of Gas from sable Island, June 2000
Meanwhile, over 4,000 jobs are expected to be created and preserved over the outlook period in the US. Figure 3.3 illustrates the pattern of employment creation and preservation over the outlook period, which is consistent with both the production outlook as well as the employment effects observed in Canada (as discussed above).

**Figure 3.3: Offshore Natural Gas Industry in Nova Scotia: Thousands of Jobs Created and Preserved in the United States, 2010 - 2035**

![Graph showing employment pattern from 2010 to 2035](graph.png)

Source: CERI

And last but not least, on a state level, economic impacts stemmed from offshore natural gas development in Nova Scotia are expected to be the greatest in the states of Massachusetts, California, Texas, New York, and New Hampshire, as shown in Table 3.4.

This concludes the discussion of the economy-wide impacts and benefits across North America from the continued operations and development of offshore natural gas projects in Nova Scotia.
Table 3.4: Economic Impacts (Millions of $ 2010 and Thousand Person Years) of Nova Scotia’s Offshore Shallow Water Natural Gas Projects in the United States, by State, 2010-2035

<table>
<thead>
<tr>
<th>State</th>
<th>GDP</th>
<th>Compensation of Employees</th>
<th>Employment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>3</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>Alaska</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Arizona</td>
<td>4</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>Arkansas</td>
<td>2</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>California</td>
<td>36</td>
<td>17</td>
<td>0</td>
</tr>
<tr>
<td>Colorado</td>
<td>4</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>Connecticut</td>
<td>4</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>Delaware</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>District of Columbia</td>
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<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Florida</td>
<td>13</td>
<td>6</td>
<td>0</td>
</tr>
<tr>
<td>Georgia</td>
<td>7</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>Hawaii</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Idaho</td>
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<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Illinois</td>
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<td>6</td>
<td>0</td>
</tr>
<tr>
<td>Indiana</td>
<td>6</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>Iowa</td>
<td>3</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Kansas</td>
<td>2</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Kentucky</td>
<td>3</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>Louisiana</td>
<td>5</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>Maine</td>
<td>18</td>
<td>9</td>
<td>0</td>
</tr>
<tr>
<td>Maryland</td>
<td>4</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>40</td>
<td>22</td>
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</tr>
<tr>
<td>Michigan</td>
<td>8</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>Minnesota</td>
<td>5</td>
<td>3</td>
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</tr>
<tr>
<td>Mississippi</td>
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<td>1</td>
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<td>2</td>
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</tr>
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</tr>
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</tr>
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</tr>
<tr>
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<td>0</td>
</tr>
<tr>
<td>Ohio</td>
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<td>5</td>
<td>0</td>
</tr>
<tr>
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<td>3</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Oregon</td>
<td>4</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>10</td>
<td>5</td>
<td>0</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>South Carolina</td>
<td>3</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>South Dakota</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Tennessee</td>
<td>5</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>Texas</td>
<td>23</td>
<td>10</td>
<td>0</td>
</tr>
<tr>
<td>Utah</td>
<td>2</td>
<td>1</td>
<td>0</td>
</tr>
<tr>
<td>Vermont</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Virginia</td>
<td>7</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>Washington</td>
<td>6</td>
<td>3</td>
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</tr>
<tr>
<td>West Virginia</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>5</td>
<td>3</td>
<td>0</td>
</tr>
<tr>
<td>Wyoming</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total US</strong></td>
<td><strong>330</strong></td>
<td><strong>167</strong></td>
<td><strong>4</strong></td>
</tr>
</tbody>
</table>

Source: CERI
Chapter 4 – Economic Impacts of Offshore Crude Oil Projects in Newfoundland and Labrador

This chapter details the economic impacts of offshore crude oil developments (including the Hibernia, Terra Nova, White Rose, and Hebron projects) in Newfoundland and Labrador and the associated impacts on the North American economies.

Impacts are calculated both for Canada and the United States, with Canadian impacts broken down to the provincial level, and US impacts both at the Petroleum Administration for Defense District (PADD) and state levels.

Economic impacts under consideration include economy-wide impacts such as value-added gross domestic product (GDP), employee compensation (including wages and supplements), jobs created and preserved (given in thousands of person-years, one person year being one person working for one year), as well as various forms of government revenues including indirect, personal, and corporate taxation revenues, but also royalty revenues from resource extraction and development.

These impacts cover all offshore industry activities including geological, geophysical, drilling, completion, tie-in, and infrastructure development associated with new projects, as well as operating activities related to existing projects as identified in the previous sections.

**Canadian Impacts**

Total investment expenditures from the offshore crude oil industry in Newfoundland and Labrador over the outlook period (2010-2035) will amount to over $35 billion, including close to $13 billion in capital expenditures and $22 billion in operating expenditures.

The cumulative sum of additional GDP from 2010 to 2035 as a result of continued operations of the Hibernia, Terra Nova, and White Rose projects and the addition of the Hebron project is estimated at over $193 billion (see Table 4.1). Close to 96 percent of the GDP impact is expected to occur in Newfoundland and Labrador, close to 3 percent in Ontario, and the remaining 1 percent across the rest of Canada.

Cumulative employee compensation over the outlook period is expected to be close to $20 billion, with 76 percent of the impact in Newfoundland and Labrador, close to 14 percent in Ontario, 4 percent in Quebec, and the remaining 6 percent across the rest of Canada.

The high proportion of the economic effects associated with Newfoundland and Labrador reflects the fact that all of the direct impact is in NL and that there are local industries that service the offshore petroleum industry.
The distribution of the economic effects in NL, across industries, will be associated with the sectorial/industrial make-up of the province, with large effects allocated to industries such as the mining and oil and gas extraction industries, finance, insurance, real estate and company management industry, as well as the public administration industry (Newfoundland and Labrador’s largest industries by GDP), but also to industries which are closely linked to the offshore petroleum industry such as the transportation and marine services industries.

Table 4.1: Economic Impacts ( Millions of $ 2010 and Thousand Person Years) of Newfoundland and Labrador Offshore Crude Oil Projects in Canada, by Province, 2010-2035

<table>
<thead>
<tr>
<th>Province</th>
<th>GDP $CAD Million</th>
<th>Compensation of Employees</th>
<th>Employment Thousand Person Years</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta</td>
<td>462</td>
<td>268</td>
<td>6</td>
</tr>
<tr>
<td>British Columbia</td>
<td>280</td>
<td>169</td>
<td>5</td>
</tr>
<tr>
<td>Manitoba</td>
<td>109</td>
<td>57</td>
<td>2</td>
</tr>
<tr>
<td>New Brunswick</td>
<td>610</td>
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<td>2,727</td>
<td>66</td>
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<tr>
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<td>1,440</td>
<td>838</td>
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</tr>
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<tr>
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<td>1</td>
<td>0</td>
</tr>
<tr>
<td><strong>Total Canada</strong></td>
<td><strong>193,466</strong></td>
<td><strong>19,969</strong></td>
<td><strong>420</strong></td>
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<table>
<thead>
<tr>
<th>Thousand Person Years</th>
<th>Direct</th>
<th>Indirect</th>
<th>Induced</th>
<th>Sum</th>
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<td>3.2</td>
<td>2.8</td>
<td>6.0</td>
</tr>
<tr>
<td>British Columbia</td>
<td>0.0</td>
<td>1.6</td>
<td>3.0</td>
<td>4.6</td>
</tr>
<tr>
<td>Manitoba</td>
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<td>0.7</td>
<td>1.0</td>
<td>1.6</td>
</tr>
<tr>
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<td>4.3</td>
<td>4.4</td>
<td>8.7</td>
</tr>
<tr>
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<td>104.3</td>
<td>97.7</td>
<td>95.3</td>
<td>297.3</td>
</tr>
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<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Nova Scotia</td>
<td>0.0</td>
<td>4.9</td>
<td>6.4</td>
<td>11.3</td>
</tr>
<tr>
<td>Nunavut</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Ontario</td>
<td>0.0</td>
<td>26.8</td>
<td>39.1</td>
<td>66.0</td>
</tr>
<tr>
<td>Prince Edward Island</td>
<td>0.0</td>
<td>0.4</td>
<td>0.4</td>
<td>0.8</td>
</tr>
<tr>
<td>Quebec</td>
<td>0.0</td>
<td>10.6</td>
<td>12.4</td>
<td>23.0</td>
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<tr>
<td>Saskatchewan</td>
<td>0.0</td>
<td>0.2</td>
<td>0.4</td>
<td>0.6</td>
</tr>
<tr>
<td>Yukon Territory</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
</tbody>
</table>

Source: CERI
The economic effects observed in other regions of the country reflect the different industrial/sectorial make-up across provinces and their association with local industries in NL impacted by offshore petroleum development. The same applies in the case for economic effects in regions across the United States, whether at the PADD or state level (discussed below).

The cumulative number of jobs created and preserved over the outlook period will amount to over 420,000 jobs, with 70 percent of the overall impact expected in Newfoundland and Labrador, 16 percent in Ontario, over 5 percent in Quebec, and the remaining 9 percent across the rest of Canada.

Direct employment effects are attributed to NL in its entirety and are related to those people that work directly for the offshore projects whether onshore (support) or offshore (operations); meanwhile, in regards to the indirect and induced employment impacts, NL will benefit from 65 percent of indirect jobs created and preserved, and 58 percent of the induced number of jobs created and preserved across Canada as a result of activity in the local offshore petroleum industry.

Indirect and induced jobs are those associated with the industries that provide goods and services for the offshore petroleum industry (indirect), such as consulting and engineering firms, insurance and finance, transportation, ship manufacturing and marine services, government departments/agencies, as well as those jobs that are created in other industries due to the level of economic activity that is generated from the offshore petroleum industry’s activity, such as jobs in wholesale and retail trade, education, and medical services (induced).

**Figure 4.1: Offshore Crude Oil Industry in Newfoundland and Labrador: Thousands of Jobs Created and Preserved in Canada, Direct (Newfoundland and Labrador) and Indirect + Induced (Across Canada), 2010-2035**

Source: CERI
Figure 4.1 depicts the pattern of employment creation and preservation in Canada as a result of industry activity in Newfoundland and Labrador’s offshore.

The employment level increases and peaks (at close to 21,000 jobs in total, and just over 5,000 direct jobs) in the third year of the outlook period (2012) as extensions at both *Hibernia* and *White Rose* are expected to come online, and thus increase the industry’s labour requirements. After that point, the level of employment decreases gradually, that is, no jobs are created and a portion of jobs are preserved, as natural declines from the fields in the existing projects bring production levels lower and lower. By 2017, however, employment levels once again start to climb as the *Hebron* project comes online and peaks by 2020 (at over 23,000 total jobs; close to 6,000 direct jobs) and gradually decreases as production levels from most projects continue to decline. By 2020, the *Terra Nova* project is expected to be decommissioned, while production from *White Rose* is expected to continue until the late 2020s. *Hibernia* is expected to continue production until 2036, while the *Hebron* project is expected to be decommissioned by 2046.

Table 4.2 illustrates the estimated cumulative taxation revenues that are expected to be collected across Canada over the outlook period, as a result of NL’s offshore projects. These include over $14 billion in indirect taxes (such as GST, PST, and HST) across Canada (close to 91 percent collected in Newfoundland and Labrador), as well as close to $15 billion in personal income taxes across Canada (93 percent in Newfoundland and Labrador), and close to over $7 billion in corporate income taxes across Canada (95 percent in Newfoundland and Labrador).

This adds to a total of about $36 billion in government tax revenues across Canada at all levels of government (including municipal, provincial, and federal) with an estimated 92 percent to be collected in Newfoundland and Labrador.

**Table 4.2: Government Taxation Revenues (Millions of $2010), by Province, 2010-2035**

<table>
<thead>
<tr>
<th></th>
<th>CAD Million</th>
<th>Indirect Tax</th>
<th>Personal Income Tax</th>
<th>Corporate Tax</th>
<th>Sum</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alberta</td>
<td>36</td>
<td>44</td>
<td>22</td>
<td>101</td>
<td></td>
</tr>
<tr>
<td>British Columbia</td>
<td>39</td>
<td>31</td>
<td>7</td>
<td>76</td>
<td></td>
</tr>
<tr>
<td>Manitoba</td>
<td>17</td>
<td>12</td>
<td>2</td>
<td>30</td>
<td></td>
</tr>
<tr>
<td>New Brunswick</td>
<td>82</td>
<td>66</td>
<td>14</td>
<td>163</td>
<td></td>
</tr>
<tr>
<td>Newfoundland &amp; Labrador</td>
<td>13,089</td>
<td>13,629</td>
<td>6,386</td>
<td>33,104</td>
<td></td>
</tr>
<tr>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td></td>
</tr>
<tr>
<td>Nova Scotia</td>
<td>117</td>
<td>89</td>
<td>22</td>
<td>228</td>
<td></td>
</tr>
<tr>
<td>Nunavut</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Ontario</td>
<td>811</td>
<td>581</td>
<td>241</td>
<td>1,633</td>
<td></td>
</tr>
<tr>
<td>Prince Edward Island</td>
<td>7</td>
<td>5</td>
<td>1</td>
<td>13</td>
<td></td>
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<tr>
<td>Quebec</td>
<td>247</td>
<td>208</td>
<td>60</td>
<td>515</td>
<td></td>
</tr>
<tr>
<td>Saskatchewan</td>
<td>7</td>
<td>4</td>
<td>3</td>
<td>14</td>
<td></td>
</tr>
<tr>
<td>Yukon Territory</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td></td>
</tr>
</tbody>
</table>

Source: CERI
Another source of government revenues is royalties. CERI estimates (Figure 4.2) that over $46 billion will be paid in royalties from offshore NL’s projects over the outlook period. These include over $24 billion paid from continued production at the Hibernia project, close to $4 billion from the Terra Nova project, over $5 billion from the White Rose project, as well as close to $13 billion in royalties paid by the Hebron project.

**Figure 4.2: Royalty Revenues (Millions of $ 2010), by Project, 2010 - 2035**

Over $4 billion in employee compensation is expected to be generated from Newfoundland and Labrador’s offshore projects across the United States, with PADDs I, II, and V being the recipients of most of those benefits over the outlook period. Meanwhile, over 102,000 jobs are expected to be created and preserved over the outlook period in the US. Figure 4.3 illustrates the pattern of employment creation and preservation over the outlook period, which is consistent with both the production outlook as well as the employment effects observed in Canada (as discussed above).
And last but not least, on a state level, economic impacts stemmed from offshore crude oil development in Newfoundland and Labrador are expected to be the greatest in the states of New York, Maine, California, Texas, and Florida as shown in Table 4.4 below.

This concludes the discussion of the economy-wide impacts and benefits across North America from the continued operations and development of new offshore crude oil projects in Newfoundland and Labrador.

November 2011
Table 4.4: Economic Impacts (Millions of $2010 and Thousand Person Years) of Newfoundland and Labrador’s Offshore Crude Oil Projects in the United States, by State, 2010-2035

<table>
<thead>
<tr>
<th>State</th>
<th>GDP</th>
<th>Compensation of Employees</th>
<th>Employment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alabama</td>
<td>79</td>
<td>42</td>
<td>1</td>
</tr>
<tr>
<td>Alaska</td>
<td>22</td>
<td>6</td>
<td>0</td>
</tr>
<tr>
<td>Arizona</td>
<td>110</td>
<td>55</td>
<td>1</td>
</tr>
<tr>
<td>Arkansas</td>
<td>49</td>
<td>23</td>
<td>1</td>
</tr>
<tr>
<td>California</td>
<td>871</td>
<td>428</td>
<td>9</td>
</tr>
<tr>
<td>Colorado</td>
<td>107</td>
<td>53</td>
<td>1</td>
</tr>
<tr>
<td>Connecticut</td>
<td>105</td>
<td>54</td>
<td>1</td>
</tr>
<tr>
<td>Delaware</td>
<td>28</td>
<td>11</td>
<td>0</td>
</tr>
<tr>
<td>District of Columbia</td>
<td>29</td>
<td>18</td>
<td>0</td>
</tr>
<tr>
<td>Florida</td>
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<td>159</td>
<td>4</td>
</tr>
<tr>
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<td>95</td>
<td>2</td>
</tr>
<tr>
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<td>11</td>
<td>0</td>
</tr>
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<td>13</td>
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</tr>
<tr>
<td>Illinois</td>
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<tr>
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<tr>
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</tr>
<tr>
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<td>29</td>
<td>1</td>
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<tr>
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<td>37</td>
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<td>998</td>
<td>549</td>
<td>12</td>
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<tr>
<td>Maryland</td>
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<td>57</td>
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</tr>
<tr>
<td>Massachusetts</td>
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</tr>
<tr>
<td>Michigan</td>
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<td>113</td>
<td>3</td>
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<td>59</td>
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<td>Montana</td>
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<td><strong>Total US</strong></td>
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</table>

Source: CERI