The Green Point Shale of Western Newfoundland

A review of its geological setting, its potential as an unconventional hydrocarbon reservoir, and its ability to be safely stimulated using the technique of hydraulic fracturing

Newfoundland Labrador
Natural Resources

A.M. Hinchey, I. Knight, G. Kilfoil, K.T. Hynes, D. Middleton and L.G. Hicks

THE GREEN POINT SHALE OF WESTERN NEWFOUNDLAND

A REVIEW OF ITS GEOLOGICAL SETTING, ITS POTENTIAL AS AN UNCONVENTIONAL HYDROCARBON RESERVOIR, AND ITS ABILITY TO BE SAFELY STIMULATED USING THE TECHNIQUE OF HYDRAULIC FRACTURING

Alana Hinchey[1] Ph.D., P.Geo.; Ian Knight[1] Ph.D.; Gerry Kilfoil[1];
Keith T. Hynes[2] P.Eng.; David Middleton[2] and Larry G. Hicks[2] P.Geo.

[1]Geological Survey, Mines Branch, Department of Natural Resources,
Government of Newfoundland and Labrador
[2]Energy Branch, Department of Natural Resources,
Government of Newfoundland and Labrador

ACKNOWLEDGMENTS

A Project Working Group was established to evaluate the state of knowledge about the Green Point shale as a target for hydrocarbon exploration and about the ability to safely stimulate the shale using hydraulic fracturing. Members included those from the Department of Natural Resources and also a representative from the Canada–Newfoundland and Labrador Offshore Petroleum Board (CNLOPB), Harry Klassen. His contribution is duly acknowledged.

The authors have benefited from the work of a number of jurisdictions and organizations and acknowledge the research of other organizations in the establishment of guidelines for industry and government. Appendix F, Further Resources, lists numerous sources of such work as well as additional sources of information.

The cover photo is an outcrop of the Green Point Formation (including the Green Point shale) taken at Green Point, Newfoundland (photo credit Larry Hicks). Cartographic support from Neil Stapleton and Dave Leonard of the Geological Survey, is greatly appreciated. The report benefited from an external review by Dr. Jeremy Hall.

TABLE OF CONTENTS

FIGURES

TABLES

REPORT HIGHLIGHTS

Along the coast of western Newfoundland, naturally occurring seeps and shows of hydrocarbons have been documented for over 150 years, leading to a long history of exploring for oil and gas in the region. This exploration targeted conventional oil and gas resources obtained in traditional ways. The current interest in unconventional hydrocarbon resources has focused attention on the Green Point shale (part of the Green Point Formation of the Cow Head Group) of western Newfoundland as a potential host to shale oil and shale gas.

In conventional reservoirs, hydrocarbons are found in porous, permeable rock layers such as sandstone or limestone that allow the natural flow of oil or gas into wells. Producing oil and gas economically from shale is more difficult because the hydrocarbons are usually trapped in impermeable rock and cannot flow naturally. Very few shale wells can achieve commercial production without artificial enhancement ("stimulation") of flow using techniques such as hydraulic fracturing. Recent advances in drilling techniques and in methods for stimulating flow in reservoirs have created new interest in the oil and gas resources in certain kinds of shale throughout North America (well known examples include the Marcellus, Bakken, and Barnett shales).

The Green Point shale of western Newfoundland differs from other unconventional shale reservoirs being developed in North America:

a. The Marcellus, Bakken, and Barnett shales, like many other unconventional reservoirs in North America, are located in basins where the layers are deformed very little, in ways that are easy to map and understand. Thousands of wells, thousands of kilometres of seismic surveys, and a significant amount of research and testing support unconventional operations of this type. Much of the information was collected during multiple cycles of exploration, so that by now the locations and properties of the hydrocarbon-bearing layers are very well known.

b. Unlike the above, the Green Point shale is not a simple package in a consistently layered sequence. The Green Point shale is part of an allochthon – a large slice of the Earth's crust that was pushed by colliding tectonic plates and moved along huge faults to a location far from its point of origin. As part of the allochthon, the Green Point shale has been folded, locally thrust over itself, thickened, or pinched out due to multiple tectonic events.

c. Scientific understanding of the Green Point shale is incomplete. Due to a lack of sufficient modern geological data, it is difficult to accurately depict or predict the extent, location, rock characteristics, or shape of Green Point shale layers below the surface.

The increased geological complexity noted above carries the potential for increased risk, so the potential of the Green Point shale as a suitable target for hydraulic fracturing must be fully and carefully evaluated. However, it is difficult to quantify the risk with the current available data. The acquisition of new data would provide valuable information about rock layers below the surface, making the risk assessment more reliable and accurate.

If a decision to consider a hydraulic fracturing application is made, a logical approach is to limit the approval to a small-scale stimulation treatment from which additional data could be obtained. This would provide new information about subsurface geology, and also valuable information about the mechanical properties and economic potential of the Green Point shale. Such information would then be used to evaluate any further potential activities.

In the event that stimulating an exploration well enabled successful recovery of commercial levels of hydrocarbons and further development were proposed, then additional assessment would be required. The government and other regulatory entities would further assess this and either allow it, modify it with appropriate controls or mitigations, or alternatively not allow it. Assessment would be unique to a proposed location, since the Green Point shale occurs, or is thought to occur, along a significant portion of the coast of western Newfoundland.

A review of available scientific literature suggests that the protection of water resources is a valid concern in relation to hydraulic fracturing operations, but not for the reasons most often publicized. Hydraulic fracturing usually occurs at safe distances from the freshwater table and aquifers, which are typically 1–3 kilometres above the shale being treated, and there are no scientifically documented cases of pollution caused directly by hydraulic fracturing itself. However, water sourcing, well integrity, and waste water handling can benefit from regulation, monitoring, and the implementation of industry best practices.

There are documented cases of natural hydrocarbon contamination in fresh water of western Newfoundland, due to the hydrocarbon seeps and shows known to occur in the region. For that reason and others, it is essential to have well-established baseline studies of the region's water resources prior to any hydraulic fracturing. There are currently no systematic programs for regional groundwater testing or for cataloguing natural seeps and shows of hydrocarbons. Without such data it will not be possible to accurately assign cause and effect once development begins.

Because hydraulic fracturing and related operations can require significant amounts of water and produce significant amounts of waste water, a detailed water resource management plan would be important for successfully managing risks. Using sea water or saline groundwater instead of fresh water is one way to mitigate concern over the use of fresh water resources. Sustainability of water sources, full disclosure of fluid additive ingredients, and the safe handling, storage, and disposal of waste water are key issues. Protection of water resources also requires stringent quality standards for the design and construction of wells used for hydraulic fracturing operations, since well integrity is crucial in preventing leaks and spills.

Relatively few peer-reviewed scientific studies have been published that systematically evaluate other specific risks associated with hydraulic fracturing and related operations. Besides impacts on air and water quality, these may include earthquake hazards and undesirable socio-economic impacts. However, the successful application of hydraulic fracturing to more than 200 000 wells in Canada alone suggests that the associated risks can be kept as low as reasonably practicable with appropriate oversight. Government jurisdictions in Canada with legislation, regulations, guidelines, and best practices to monitor, evaluate, and allow the use of hydraulic fracturing include Alberta, British Columbia, and Saskatchewan.

OVERVIEW

PREPARATION

This report was prepared by a cross-disciplinary working group representing expertise in field mapping, petroleum geology, geophysics, and engineering. As part of their task, the group reviewed information from a variety of sources including scientific studies, reports, well logs, published geological data, model standards, and best management practices. They also reviewed regulations in other North American jurisdictions.

PURPOSE AND SCOPE

The petroleum industry has expressed an interest in the economic potential of certain rock layers, known as the Green Point shale, in western Newfoundland. Specifically, there is interest in shale plays that can produce economic quantities of gas and oil. The production of economic quantities of this type of resource usually requires hydraulic fracturing or "fracking".

The purpose of the report is to provide background information on this topic for a general audience. It contains basic information about the geology of western Newfoundland and the Green Point shale, about the region's history of hydrocarbon exploration and the nature of its hydrocarbon resources, and about the process of hydraulic fracturing, including a summary of the opportunities and risks of applying the technology to the Green Point shale, based on documented experience from other jurisdictions.

In evaluating those opportunities and risks, the working group focused on comparisons with documented shale reservoirs, specifically with respect to the use of hydraulic fracturing in other North American jurisdictions. The report does not contain an exhaustive review, but it describes examples that are similar to western Newfoundland and reviews the most relevant best practices.

The report also provides a variety of other resources designed to make this and perhaps other related reports accessible to its readers. These include a brief review of regulatory authorities, a glossary of definitions, a list of acronyms, and an extensive bibliography.

INTRODUCTION

Natural seeps and shows of hydrocarbons have been known on the west coast of Newfoundland since the 1800s (Figure 1), and exploration for oil has been ongoing periodically for about a hundred years. Historically, exploration and drilling has targeted oil and gas (hydrocarbon) resources that could be obtained from "conventional" reservoirs. Until a few decades ago, crude oil was largely extracted from the ground by drilling a vertical well into a hydrocarbon reservoir and allowing oil or gas to flow into the well due to natural pressures (*see* Table 1 and Figure 2). Hydraulic fracturing has had a place in conventional operations, where it is often used to improve oil flow and assist recovery.

Producing oil and gas economically from shale is more difficult. In the nineteenth century, early efforts involved mining the shale and extracting petroleum products in a factory setting. It has only been possible to extract commercial levels of hydrocarbons by drilling wells in shale since the 1980s.

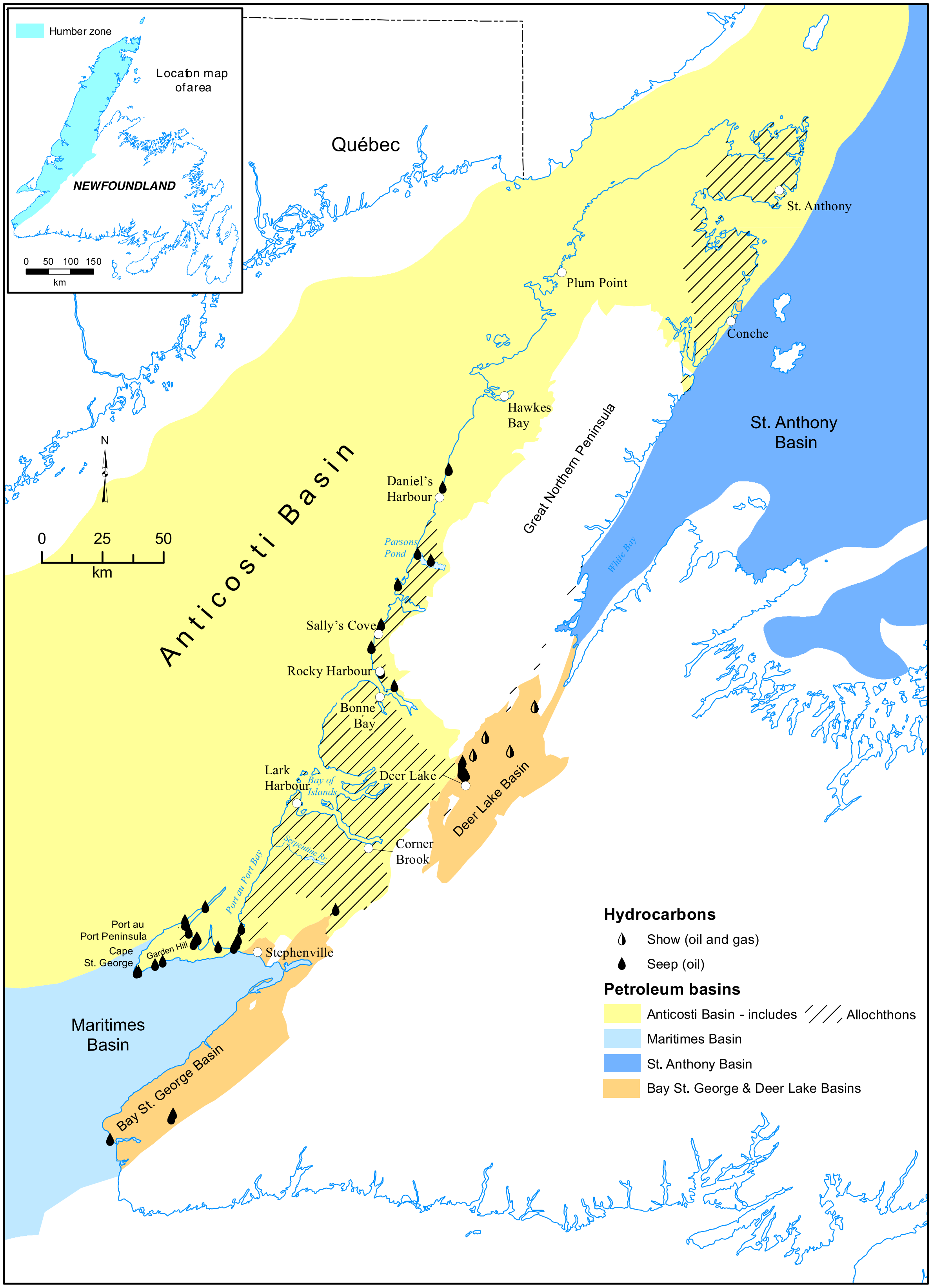


Figure 1. *Seeps and shows of hydrocarbon in western Newfoundland. Locations are superimposed on a map of the region's onshore and offshore petroleum basins.*

Table 1. Conventional vs unconventional petroleum resources

Conventional Plays	**Unconventional Plays**
Hydrocarbon occurs in rock (typically sandstone or limestone) that is permeable enough to allow gas or oil to flow naturally.	Hydrocarbon occurs in rock that is not permeable enough to allow natural flow (*e.g.*, tight sandstone, shale, or coal); the gas or oil is trapped.
Vertical or horizontal drilling can be used.	Horizontal drilling and modern stimulation techniques are required.
Hydrocarbons flow into the well naturally through interconnected rock pores.	Hydrocarbons flow into the well through natural and artificially created fractures.
The rate and amount of production are determined by physical characteristics like the porosity and permeability of the reservoir.	The potential for production is indicated by chemical and other characteristics like total organic carbon, thermal maturity, and mineral composition of the reservoir.
Development is planned for an entire field.	Development is specific to each well.

Note: Modified from Halliburton, E.ON presentation, Prospects for unconventional gas in Europe, February 5, 2010, as found in Gény (2010, p. 104)

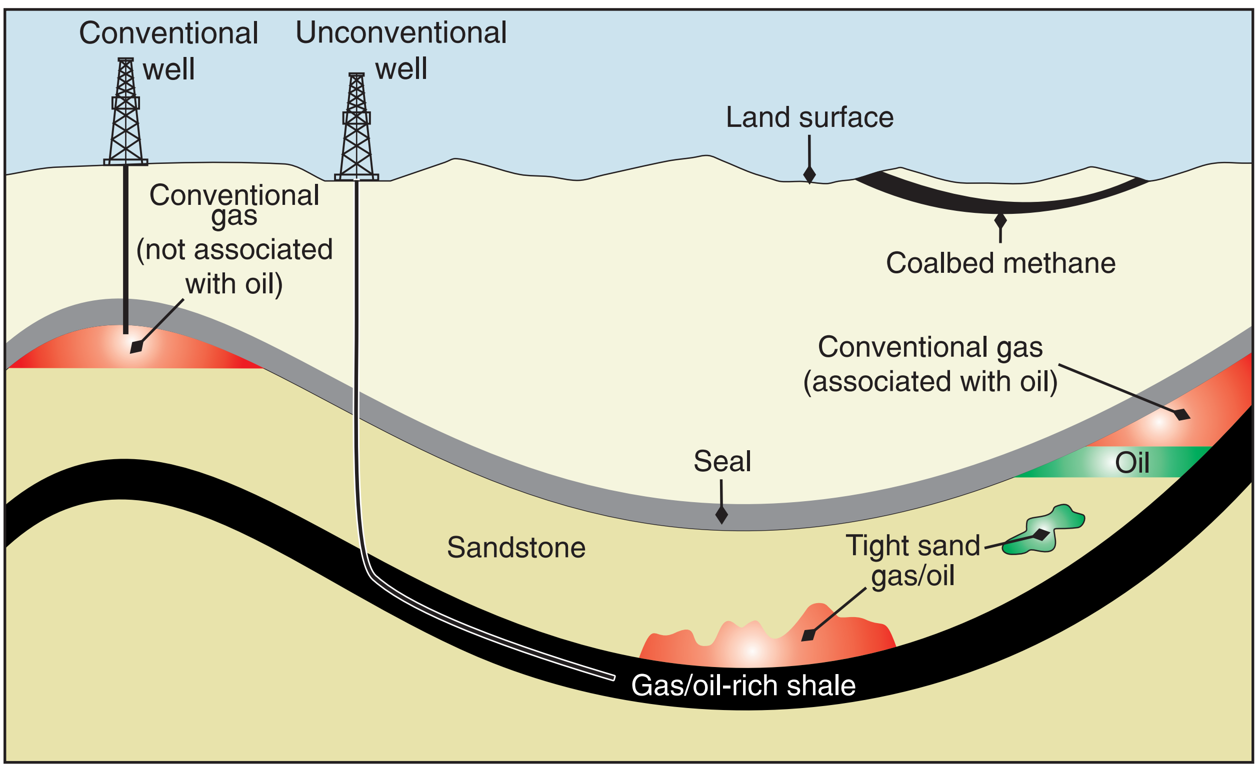


Figure 2. *Schematic geology of natural gas and oil resources. Note that hydrocarbons trapped in the arch-like structures ("anticlines") are the main target of conventional wells. Natural gas may be associated with accumulations of oil or may form a reservoir with no oil. Modified from Massachusetts Institute of Technology (2011, Figure 2.2, p. 19).*

When hydrocarbons are trapped in shale they cannot flow naturally, so very few shale wells can achieve commercial production without improving flow. Horizontal drilling and multi-stage hydraulic fracturing have provided this improvement in flow and have created new interest in the "unconventional" oil and gas resources (*see* Table 1 and Figure 2) in certain kinds of shale throughout North America. This interest also includes the west coast of Newfoundland, where the target is the Green Point shale.

To provide a foundation of understanding for anyone interested in these issues, this report provides a sequence of topics as follows:

1. The geological features of western Newfoundland formed over a period of hundreds of millions of years. This section contains basic background information about the region's geological history (1.1). It then describes the major rock formations, from oldest to youngest (1.2), and reviews how they were deformed during episodes of mountain-building (1.3). The geology of the Green Point Formation and its place in the Cow Head Group is explained (1.4), and the section ends by outlining geophysical data that provide further insights into the geological history of the region (1.5).

2. Hydrocarbon exploration in Newfoundland has a long history dating back to the early 1800s. It has included the search for conventional and, more recently, unconventional reservoirs of oil and gas. This section provides some background information about hydrocarbon reservoirs and describes the geological context of unconventional shale reservoirs (2.1). It reviews the history of hydrocarbon exploration in western Newfoundland (2.2) and outlines the petroleum geology of the region (2.3).

3. For unconventional hydrocarbon reservoirs such as shale plays, in order to get the oil or gas to flow to the surface for collection, the permeability of the shale needs to be enhanced using techniques called "stimulation". This section reviews some basic background information about stimulation techniques, including processes and procedures in drilling and preparing the well (3.1) and a description of hydraulic fracturing (3.2). It also explains the three stages in developing an unconventional reservoir (3.3) and includes a discussion of specific stimulation techniques and other considerations (3.4). Because hydraulic fracturing and related operations require significant amounts of water and produce significant volumes of waste water, there is also a brief review of provincial water-related regulations and baseline data (3.5).

4. The development of any natural resources, including oil and gas, comes with consequences; there will always be an environmental impact associated with these practices. However, the development of shale resources, through horizontal drilling and the application of hydraulic fracturing techniques, also provides significant economic potential. Knowing the risks and managing them diligently allow the benefits to be derived with a minimum negative impact. This section addresses aspects of hydraulic fracturing that are most commonly a subject of public concern (4.1–4.9) and provides an overview of the risks (4.10).

5. This section provides a summary of opportunities and risks related to shale development in western Newfoundland. Key points from the report are summarized (5.1) and best practices recommended (5.2). The section concludes with a note recommending a future re-evaluation as technologies and issues continue to evolve (5.3).

1. GEOLOGY OF WESTERN NEWFOUNDLAND

The geology of western Newfoundland developed as the result of many Earth processes acting over long periods of geological time. This section briefly describes the background geological framework of Newfoundland (1.1) and the resulting rock formations, from oldest to youngest (1.2). It then explains how they were deformed by numerous tectonic events (1.3). Following this is a discussion focusing on the geology of the Green Point Formation and the Cow Head Group of which it is a part (1.4). The section ends by describing the results of geophysical surveys that allow geologists to "see" into rock layers below the surface, providing them with a more complete understanding of the region (1.5).

The account of the geology of western Newfoundland found in this report is based primarily on work published by the federal and provincial geological surveys, including Bostock and others (1983), James and Stevens (1986), James and others (1988, 1989), Hyde (1995), Knight (1983, 1994, 1995, 1997, 2013), Knight and Boyce (1991), Knight and James (1988), Knight and others (2007), Stockmal and Waldron (1990), Van de Poll and others (1995), Waldron and Palmer (2000), Waldron and Stockmal (1991), and Waldron and others (1998). These and other related works are listed in Appendix F, Further Resources.

1.1 BACKGROUND GEOLOGICAL HISTORY OF NEWFOUNDLAND

Geologically, the island of Newfoundland is divided into three areas – the Western (or Humber) Zone, the Central Zone, and the Eastern Zone (Figure 3). The Humber Zone has been part of North America for at least the last billion (1 000 000 000) years and is the focus of this report. *See* Appendix A for a summary of the geological time scale.

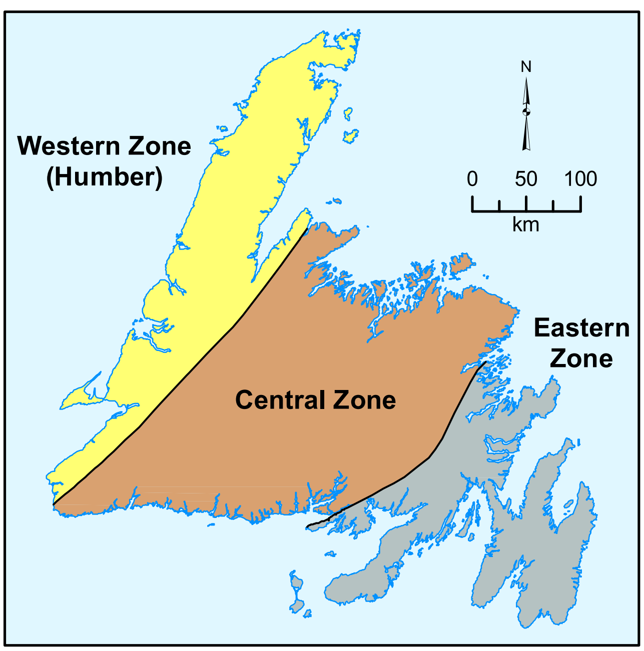


Figure 3. *Simplified tectonic zones of Newfoundland. Although all of Newfoundland was affected by formation of the Appalachian Mountains, each of the province's simplified tectonic zones in Newfoundland has a distinct geological history.*

In the Proterozoic era, about 900 million years ago, the Earth was dominated by a single, large supercontinent geologists have called Rodinia; it was surrounded by a single global ocean. By the latest Proterozoic, about 600 million years ago, this supercontinent had broken into smaller continents separated by oceans (Figure 4a). Two of these ancient continents, Laurentia and Gondwana, developed following the break-up. Gondwana consisted of present-day Africa, Arabia, Antarctica, Australia, and India. Laurentia essentially coincides with modern day North America, including Greenland, although it also contained small areas now found in the British Isles and Ireland. The Iapetus Ocean, which formed between Gondwana and Laurentia, grew wider as sea-floor spreading along its mid-ocean ridge pushed the continents farther apart.

The Humber Zone of Newfoundland formed the eastern edge of Laurentia on the northwestern margin of the Iapetus Ocean. Sediment, formed by the weathering of surrounding hills, was transported by water and deposited in layers on the ocean floor along the continental margin of Laurentia. Over a long period of time, a great thickness of sediment accumulated, much like the blanket of sediment that covers the present-day continental shelf off North America's Atlantic shores. A portion of the sediment deposited along the continental margin of Laurentia became the present-day Green Point shale.

During the deposition of sediment in the middle Cambrian, about 515 million years ago, a subduction zone developed within the Iapetus Ocean near its margin with Laurentia, much like the "Ring of Fire" that exists around today's Pacific Ocean (Figure 4b). Subsequently, volcanic island arcs developed above the subduction zones, where Iapetus Ocean crust was descending into the Earth's mantle and melting to feed volcanic eruptions. This volcanic activity continued until about 460 million years ago.

Because the Iapetus Ocean sea floor was being consumed in the subduction zone, the ocean began to close, and Laurentia and Gondwana slowly converged. As this happened, the huge force of the colliding tectonic plates pushed slices of ocean floor onto the margin of Laurentia. The slices included continental shelf sediments, volcanic rocks of the ocean floor itself, and even slivers of the Earth's mantle below the ocean floor. Today all these slices are stacked up in the Humber Zone as "allochthons". The mantle rock in the allochthons is made famous in the Tablelands of Gros Morne National Park.

Geologists have had to create names for the various pieces of Earth's crust torn apart and rearranged by plate collisions. "Allochthon" is the term used to describe a slice of the Earth's crust that has been moved by tectonic forces to a place far from its point of origin; portions of crust that remain essentially in place throughout their history are termed "autochthons". Displaced or exposed slices of the volcanic ocean floor and associated mantle are called "ophiolites".

By the late Ordovician, 450 million years ago, the Iapetus Ocean had shrunk to a small remnant, destroyed as island arcs and continents collided with each other. The small continent of Avalonia (of which the Avalon Peninsula is a remnant) first collided with the volcanic island arcs of Iapetus and then with Laurentia. At a later time, the much larger continent of Gondwana collided with Laurentia. By early Devonian, 410 million years ago, a huge new supercontinent called Pangea had formed from these collisions (Figure 4c).

By that time, the portion of the Earth's crust that would later become Newfoundland was located in the interior of the Pangean supercontinent as part of a huge mountain range. Marking the line along which the Iapetus Ocean had vanished, this Pangean mountain range was similar in height and length to modern equivalents such as the Rockies and the Himalayas. The southern half of the range now forms the Appalachian Mountains of eastern North America, running from Alabama to Newfoundland. The northern half is found across the Atlantic Ocean in Scotland and Scandinavia.

Pangea stayed welded together until early Jurassic time, about 200 million years ago. It broke apart to form the present Atlantic Ocean, which continues to open today (Figure 4d). The Atlantic Ocean opened along a line that was similar, but not identical, to the old Iapetus Ocean. Bits of Gondwana (including Newfoundland's Eastern Zone) were left behind, attached to North America. Gondwana itself eventually broke apart to form Africa, South America, India, Australia, and Antarctica.

1.2 MAJOR GEOLOGICAL SUBDIVISIONS OF WESTERN NEWFOUNDLAND

The focus of this report is the westernmost portion of the Humber Zone. This portion is called the external Humber Zone because it lies along the outer edge of the Appalachian Mountains, near the stable Canadian Shield and away from the site of continental collision. The more eastern portion of the Humber Zone, called the internal Humber Zone, is dominated by metamorphic rocks and is not described here.

As summarized in section 1.1, the external Humber Zone of western Newfoundland is host to rocks that formed between about 610 and 390 million years ago, preserving the history of an ancient continental margin. Figure 5 is a geological map of the whole region, and Figure 6 shows a more detailed view of the geology in the Port au Port area. Many of the region's sedimentary rocks formed in a continental shelf or continental slope environment, both of which are illustrated in Figure 7. The overall sequence of sedimentary rocks in western Newfoundland is summarized in Figure 8.

In the following sections, the region's six main geological elements are described in order from oldest to youngest. Note that a "sequence" or "succession" of sediments is a group of individual layers that formed during a single block of time and in a similar setting.

1.2.1 BASEMENT ROCKS

On the island of Newfoundland, the Humber Zone contains the oldest rocks, which are granitic and metamorphic rocks at least a billion years old. As part of the Canadian Shield, they form the continental basement, or foundation, upon which all other rocks of the region are resting. As noted in section 1.1, these basement rocks were part of a supercontinent, Rodinia, that contained all the Earth's landmasses of that time. When Rodinia broke apart about 700 to 600 million years ago, western Newfoundland then lay along the edge of the continent geologists have named Laurentia.

In many parts of western Newfoundland these ancient rocks lie far beneath the surface, buried by younger layers of rock. However, they can be seen in the Long Range Mountains of the Great Northern Peninsula from Gros Morne National Park to Canada Bay (light pink area in Figure 5).

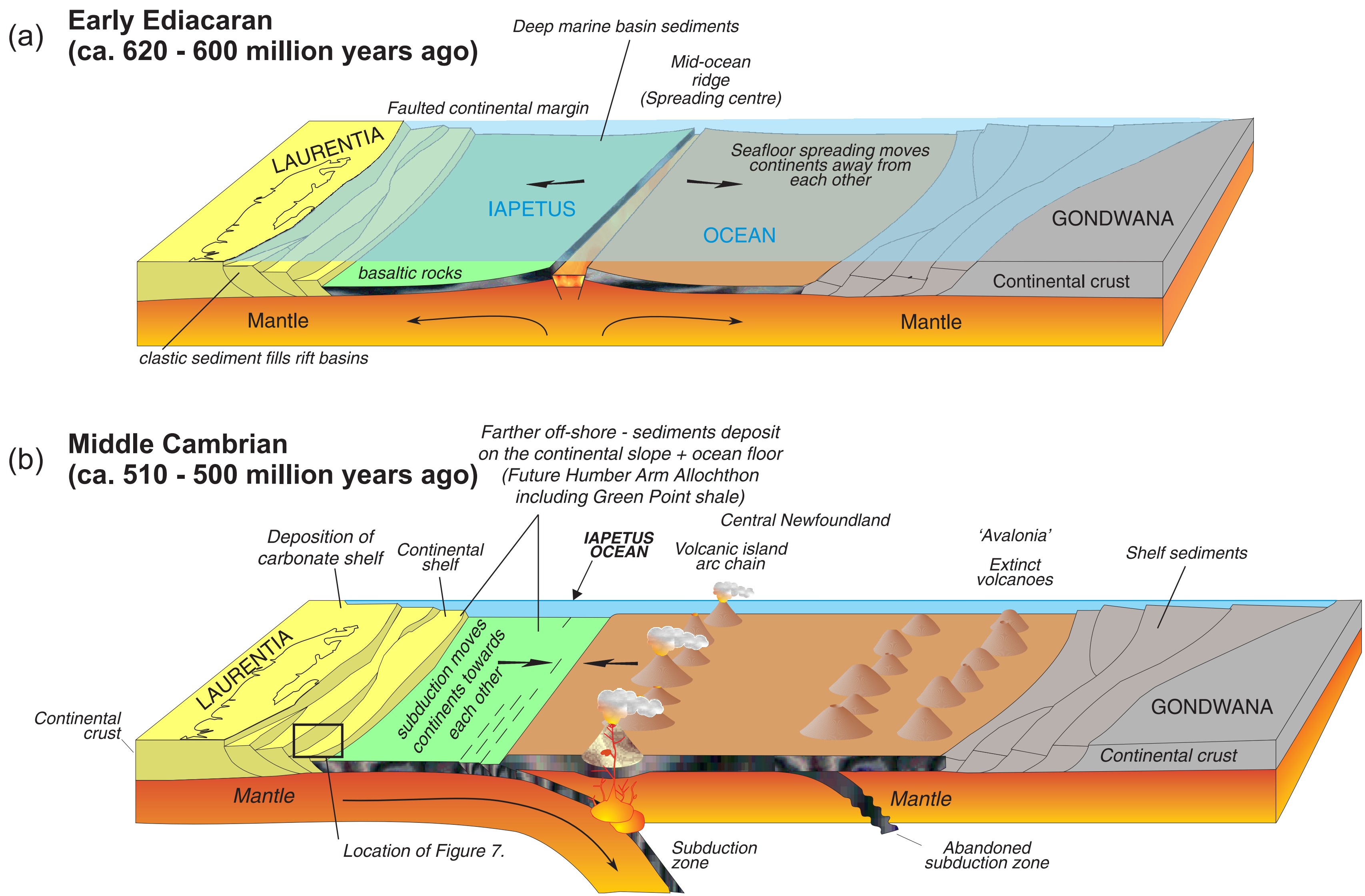


Figure 4. *Evolution of the rocks of Newfoundland through time.* ***(a)*** *Rodinia splits up and the Iapetus Ocean grows wider, about 620 million years ago (Early Ediacaran period).* ***(b)*** *Volcanic islands form beyond the continental shelf as subduction begins, about 515 million years ago (Middle Cambrian period). Modified from Colman-Sadd and Scott (1994).*

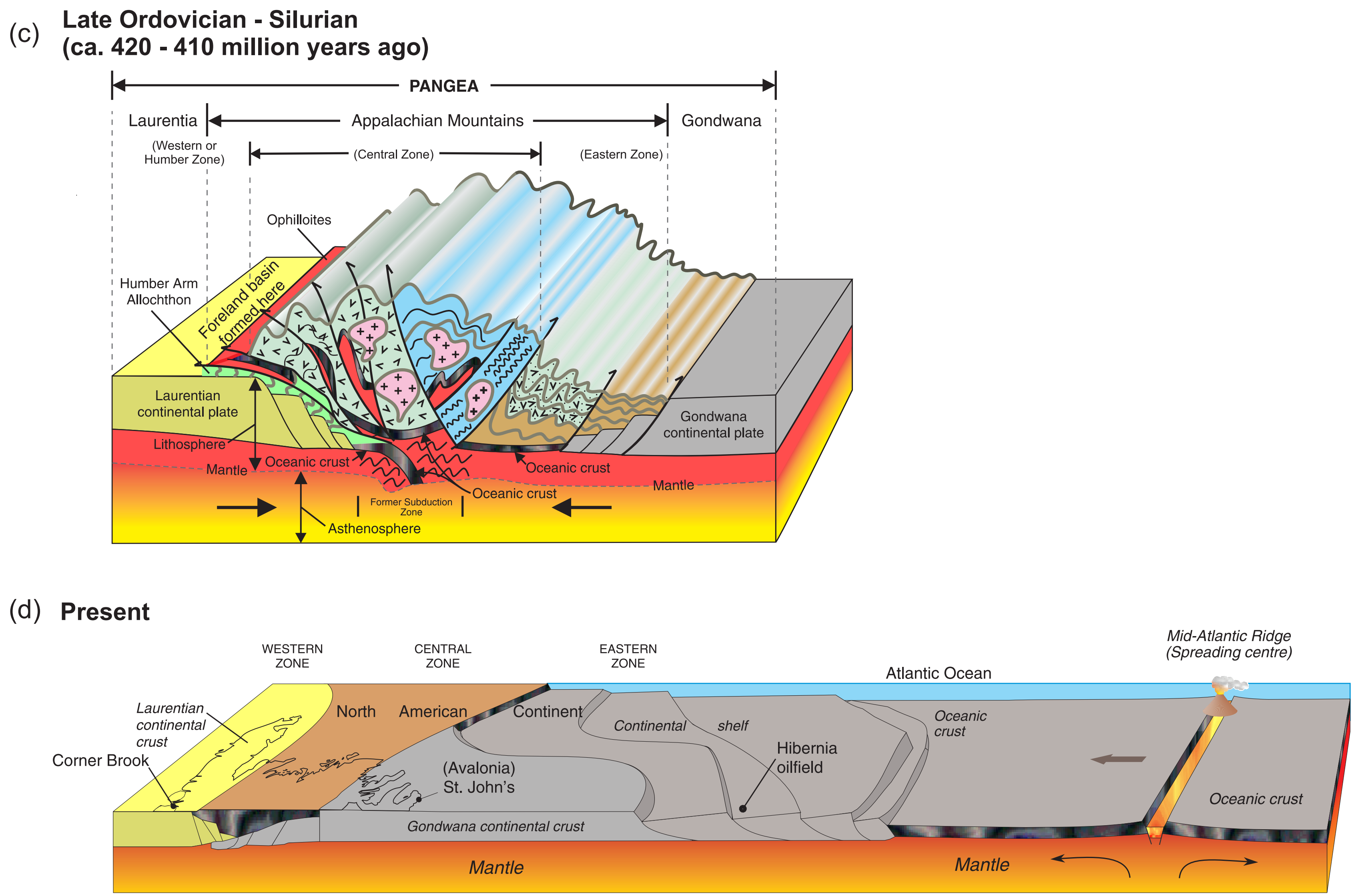
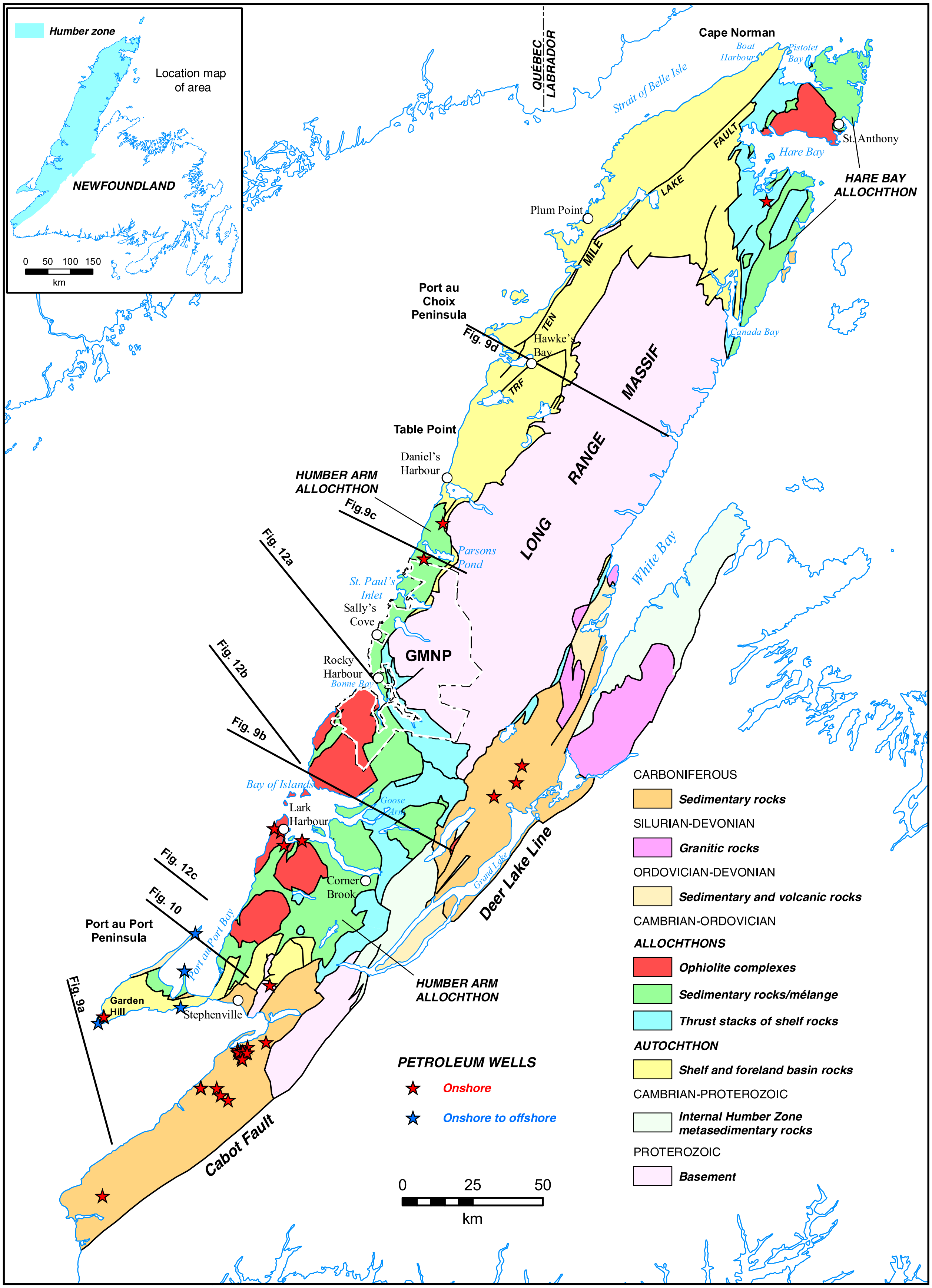


Figure 4 continued. *Evolution of the rocks of Newfoundland through time.* ***(c)*** *Continental collision causes crustal thickening, about 420 to 410 million years ago (Late Ordovician–Silurian period). Modified from Kean (2010).* ***(d)*** *Newfoundland's tectonic zones lie on a stable continental margin (present day). Modified from Colman-Sadd and Scott (1994).*


Humber zone
Location map of area
NEWFOUNDLAND
0 50 100 150
km
QUÉBEC
LABRADOR
Cape Norman
Boat Harbour
Pistolet Bay
Strait of Belle Isle
St. Anthony
Hare Bay
HARE BAY ALLOCHTHON
TEN MILE LAKE FAULT
Plum Point
Port au Choix Peninsula
Fig. 9d
Hawke's Bay
TRF
Canada Bay
LONG RANGE MASSIF
Table Point
Daniel's Harbour
HUMBER ARM ALLOCHTHON
Fig.9c
Parsons Pond
Fig. 12a
St. Paul's Inlet
Sally's Cove
GMNP
White Bay
Fig. 12b
Rocky Harbour
Bonne Bay
Fig. 9b
Bay of Islands
Lark Harbour
Goose Arm
Corner Brook
Grand Lake
Deer Lake Line
Fig. 12c
Fig. 10
Port au Port Peninsula
Port au Port Bay
Garden Hill
Stephenville
Fig. 9a
HUMBER ARM ALLOCHTHON
Cabot Fault
PETROLEUM WELLS
Onshore
Onshore to offshore
0 25 50
km
CARBONIFEROUS
Sedimentary rocks
SILURIAN-DEVONIAN
Granitic rocks
ORDOVICIAN-DEVONIAN
Sedimentary and volcanic rocks
CAMBRIAN-ORDOVICIAN
ALLOCHTHONS
Ophiolite complexes
Sedimentary rocks/mélange
Thrust stacks of shelf rocks
AUTOCHTHON
Shelf and foreland basin rocks
CAMBRIAN-PROTEROZOIC
Internal Humber Zone metasedimentary rocks
PROTEROZOIC
Basement

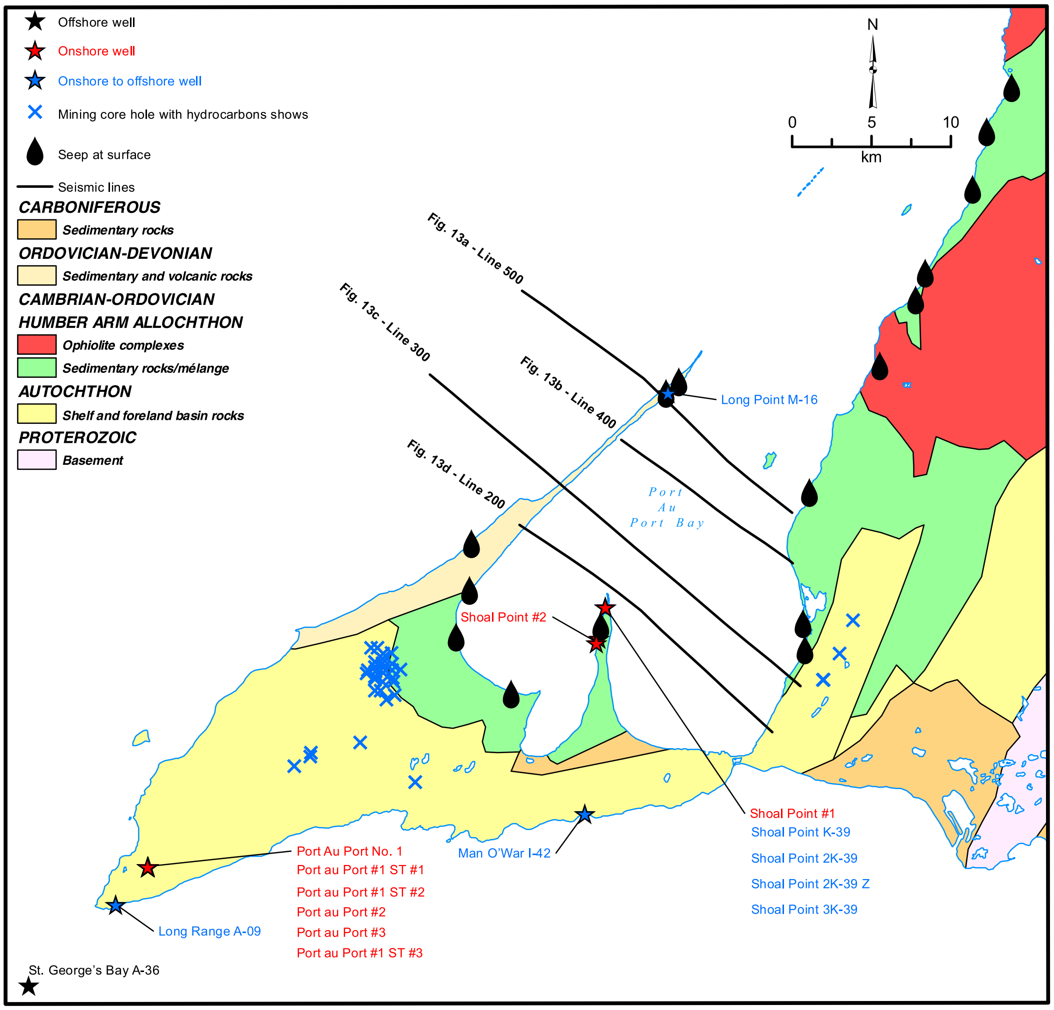


Figure 6. *Geology and hydrocarbon exploration on the Port au Port Peninsula. Rock units in the legend are listed from youngest to oldest. The extent and location of each cross-section in Figure 13 is indicated by a correspoding line on the map. The map also shows the location of known oil seeps and shows and petroleum wells in the region.* See *Appendix B for more information about the wells. Geology modified from Knight (2013).*

Figure 5 (page 12). *Simplified geology of western Newfoundland. Rock units in the legend are listed from youngest to oldest. The extent and location of each cross-section in Figures 9, 10 and 12 is indicated by a corresponding line on the map. The map also shows the locations of wells drilled since 1990. See Appendix B for more information about the wells.* ***GMNP****, Gros Morne National Park. Map modified from Knight (2013).*

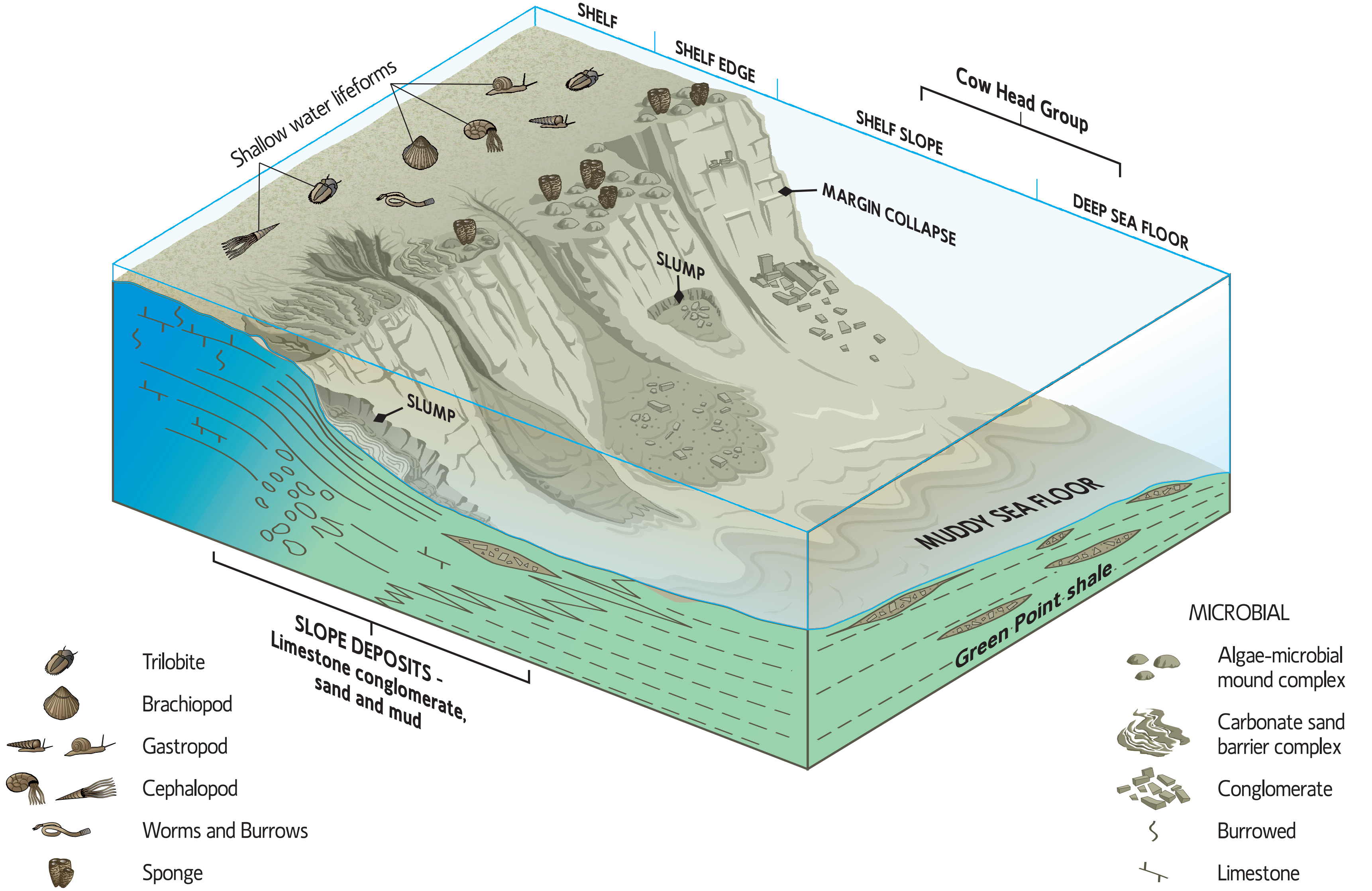


Figure 7. *Western Newfoundland during deposition of the Green Point shale. During the lower Paleozoic, western Newfoundland lay on the quiet continental margin of Laurentia and was covered by the Iapetus Ocean. Some rocks formed a carbonate platform on the shallow continental shelf, but the Green Point shale and other rocks now found in the Humber Arm Allochthon formed in the deeper waters of the continental slope and ocean floor.*

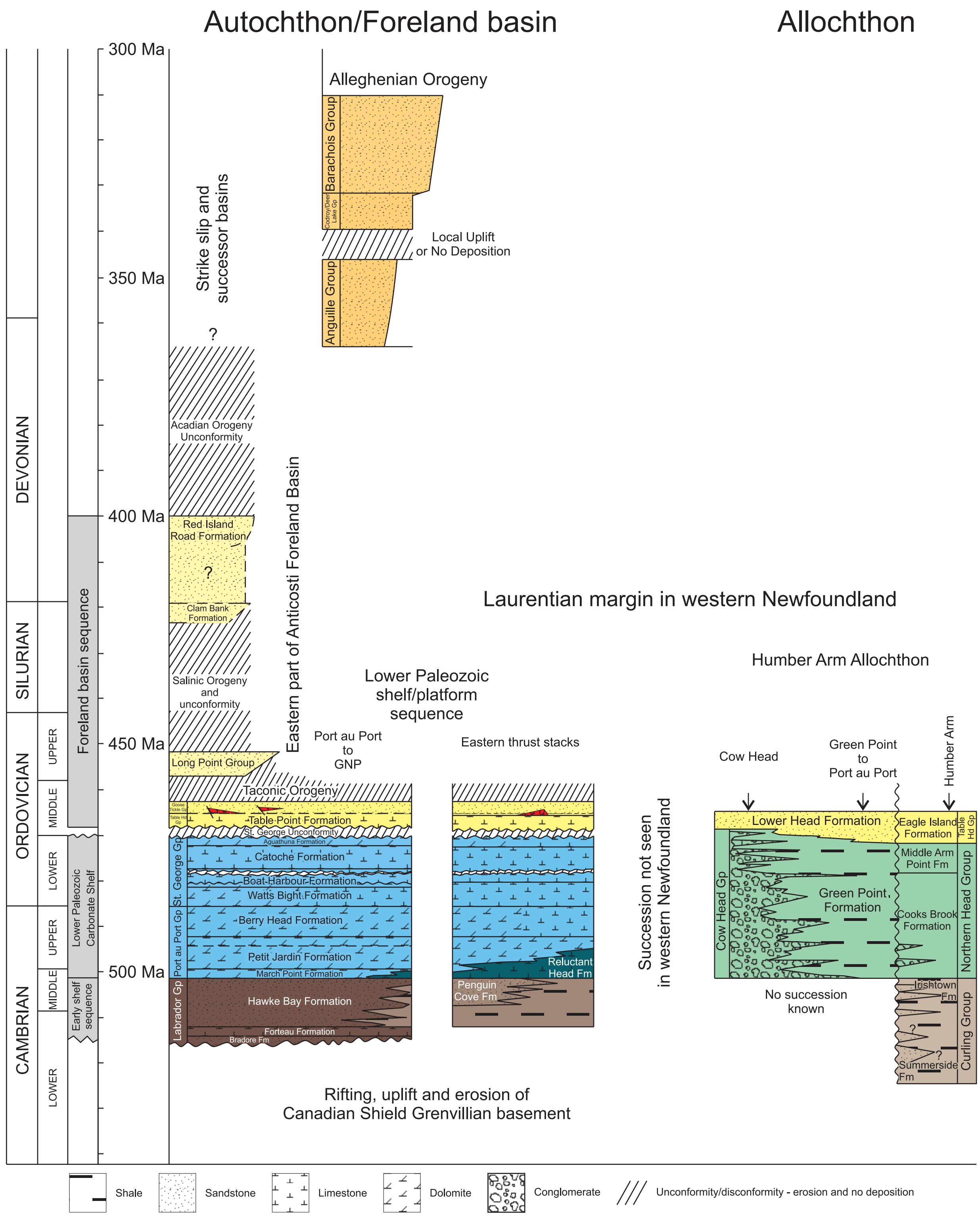


Figure 8. *Stratigraphic column for western Newfoundland. On the far left is a portion of the geological time scale with period names and dates. The stratigraphic column on the left (Autochthon/Foreland basin) represents rock layers formed in place on the continental margin and foreland basin. The stratigraphic column on the right (Allochthon) represents rock layers formed on the adjacent continental slope and later displaced during the Taconic Orogeny. The same colour scheme is used in Figures 9, 10, 12, 13, 21 and 23. Modified from Cooper and others (2001).*

1.2.2 RIFT ROCKS

The continental margin of Laurentia formed when the Iapetus Ocean opened between 610 and 520 million years ago. The process took a long time: For almost 100 million years volcanic rocks as well as layer upon layer of sandstone, shale, and conglomerate were deposited in narrow rift valleys and narrow seaways that fringed the edge of the continent.

Geologists call the whole sequence of layers that formed in this way a rift sequence (labelled “Rift Basins” in Figure A.1). Thick successions of these sandstone, shale, and conglomerate layers are now found in deformed parts of the Taconic allochthons (*see* section 1.3.1). Rift rocks confined to small areas on the Great Northern Peninsula play no further part in this discussion.

1.2.3 LOWER PALEOZOIC SEDIMENTARY ROCKS

By the Lower Paleozoic period, the rifting process was complete. The continental margin as it likely existed at that time is illustrated in Figure 7. The following two sections discuss rocks formed during the same time period but on different parts of the continental margin – the relatively shallow continental shelf (1.2.3.1) and the deeper continental slope and sea floor farther offshore (1.2.3.2). Figure 8 shows the age and sequence of each group of layers.

In addition to sediments made from bits of weathered rock (as are sandstone and shale), along the continental margin “carbonate” sediments also formed. These include limestone (calcium carbonate) and dolostone (calcium-magnesium carbonate). Most carbonate rocks form from the minerals in sea water.

1.2.3.1 Sedimentary Rocks of the Continental Shelf

To understand the continental shelf of Laurentia, think of a tropical, azure-coloured sea in which white carbonate sediment was deposited, much like the Bahama Banks of today. This environment stretched for over 400 kilometres southwest to northeast and then likely beyond this into Quebec, Greenland, and Scotland. The sediments formed in this way are about 1.5 kilometres thick. Geologists call this accumulation of layers the carbonate shelf or continental shelf rocks (*see* Figure 8). Only the near-shore to middle part of the shelf sequence is preserved in western Newfoundland; the outer part of the shelf and the shelf margin were destroyed or deeply buried as the Appalachian Mountains formed.

Carbonate shelf evolution. The continental shelf succession seen in western Newfoundland is divided into three parts, the Labrador Group, Port au Port Group, and St. George Group (Figure 8). The Labrador Group includes sandstone, limestone, and shale. The limestone preserves some of the earliest ocean reefs known in geological history. Above the Labrador Group are the Port au Port Group and the St. George Group. They consist of limestone and dolostone deposited in shallow seas and around shorelines of the tropical continental shelf, which is believed to have prospered in a global “greenhouse” climate. These layers are sometimes referred to as a “carbonate platform”.

Abundant burrowing and shelly organisms such as snails and trilobites lived on the shelf. At times when sea level was high, the shelf was an expansive sea, and the sea floor was covered mainly by fine-grained carbonate mud. In some areas, huge tracts of carbonate sand formed shifting sand barriers similar to those seen today on the western and southern edge of the Bahama Banks. At other times, when sea level was lower, the shelf was dotted with many carbonate islands in a setting with beaches, muddy tidal flats, lagoons, and algal mounds.

St. George Unconformity. A feature known as the St. George Unconformity tells an important part of the geological story in western Newfoundland. It is also important to Newfoundland's hydrocarbon resources. The unconformity is located at the top of the St. George Group (Figure 8). It formed when sea level fell below the edge of the continental shelf, exposing the carbonate rocks already deposited there. Similar features along the ancient margin of Laurentia can be recognized as far south as Texas, suggesting that it probably formed because of a global lowering of sea level.

Geological evidence suggests that the Taconic Orogeny (*see* section 1.3) began to affect western Newfoundland around this same time. Earth movements faulted the carbonate platform and some areas were uplifted, creating a significant amount of topographic relief on the exposed shelf. Erosion produced a very hilly landscape, and cave systems formed – mostly where faults and cracks opened to the land surface. Evidence of this topographic relief and of the ancient cave systems is found on the Port au Port Peninsula and near Port au Choix on the Great Northern Peninsula.

The St. George Unconformity was quickly submerged when sea level rose again, partly due to a global change and partly assisted by local tectonic events of the Taconic Orogeny. Limestone of the Table Head Group (Figure 8) was deposited as the sea deepened on the continental shelf, marking the first deposits of a foreland basin (*see* section 1.2.4).

Porous dolostone. Rock formations important to the hydrocarbon story of western Newfoundland include the Catoche and Aguathuna formations at the top of the St. George Group (Figure 8). They are targets for conventional petroleum operations (*see* section 2.3). The cave system linked to the St. George Unconformity provides one type of reservoir. However, the primary target recently has been sequences of crystalline dolostone formed by the alteration of deeply buried limestone.

Under the right conditions, especially close to faults, crystalline dolostone can replace any type of limestone of any age. Such dolostone, commonly very porous, is believed to have hosted an oil field in the Catoche Formation of the St. George Group at Port au Choix. There, geologists have found signs of formerly oil-rich layers and conclude that oil might still be found in nearby parts of the same rock formation (Cooper and others, 2001). The same dolostone unit was host to the zinc deposit mined near Daniel's Harbour. It also appears likely an oil or gas field may have existed in dolostone that replaced limestone conglomerate and carbonate sand at the Arches Provincial Park just north of Parsons Pond.

1.2.3.2 Sedimentary Rocks of the Continental Slope and Ocean Floor

A sequence of deep-water sedimentary rock layers formed on the continental slope and ocean floor (Figure 7) at the same time as the shallow-water continental shelf rocks described above. Research indicates these continental slope and ocean floor rocks formed as far as 200 kilometres east of their present location. They are now found geographically from the Port au Port Peninsula to the tip of the Great Northern Peninsula. This distinctive sequence is shown in Figures 5, 6, and 8 as the Humber Arm Allochthon. Complexly folded and faulted during the Taconic Orogeny, they form the Cow Head Group, which includes the Green Point Formation (*see* section 1.4).

Rock formations in the Bay of Islands area – such as the Cook's Brook Formation and the Middle Arm Point Formation of the Northern Arm Group (Botsford, 1988) – also formed on the continental slope, and are correlated with the Cow Head Group. They are not only deformed but also metamorphosed (changed by high temperature and pressure deep in the Earth), making them unsuitable for hydrocarbon exploration. They form no further part of this discussion.

1.2.4 FORELAND BASIN ROCKS

As the Iapetus Ocean closed, bringing continental masses into contact (*see* section 1.1), a new feature called the Anticosti Basin formed and became the site of a new sequence of sedimentary rock layers. The Anticosti Basin is a "foreland basin" centred in the northern Gulf of St. Lawrence. For more information about foreland basins, *see* section 2.1.4. Seismic surveys (section 1.5.1) and other evidence suggest that the Anticosti Basin is elongated on a northeast-southwest axis. The accumulation of sedimentary rock layers in the basin appears to become thinner toward the west and north.

The basin had a prolonged history of sediment deposition (Figure 8) including limestone, shale, sandstone, and conglomerate. Geological evidence indicates that the basin first began to form in the Middle Ordovician, about 470 million years ago. However, sedimentary rocks found only on the Port au Port Peninsula indicate that pulses of deposition also occurred in the Late Ordovician (455 million years ago), the Late Silurian (420 million years ago), and the Middle Devonian (about 400 million years ago).

Black shale of the Black Cove Formation in the Goose Tickle Group is part of the foreland basin sequence. It is known to be rich in organic matter, with a total organic carbon content of up to 2%, and is believed to contain gas rather than oil. The shale is similar to, although older than, the Utica Shale, a known producer of hydrocarbons in New York and Ohio. *See* section 2.1.4 for more information about foreland basin rocks in hydrocarbon exploration.

1.2.5 CARBONIFEROUS SEDIMENTARY BASINS

Two Carboniferous basins – the Bay St. George Basin and the Deer Lake Basin – are located onshore in western Newfoundland (Figures 1 and 5). The Bay St. George Basin extends offshore into the southern Gulf of St. Lawrence, where it is referred to as the Magdalen or Maritimes Basin. Carboniferous sediments are also preserved within offshore basins to the south (in the Sydney Basin) and north of Newfoundland (in the St. Anthony Basin), where they are locally overlain by younger, Mesozoic rock layers.

The Bay St. George and Deer Lake basins occur along the trace of a major fault system collectively known in Newfoundland as the Cabot Fault. The fault system extends from the Codroy Valley in the southwest to White Bay and Conche in the northeast. Rocks formed from the sediments deposited by lakes and rivers predominantly fill the basins. They generally share a common history, with some differences including the existence of marine sediments in the Bay St. George Basin.

The Cabot Fault is part of a widespread regional fault system that occurs throughout the Maritime Provinces. It was fundamental in the formation of the Carboniferous Magdalen Basin in the Maritime Provinces and under the southern Gulf of St. Lawrence. The resulting basins accumulated up to 7–10 kilometres of sedimentary rock during a period of 50 million years. Carboniferous basins were subsequently deformed during the Alleghenian Orogeny (*see* section 1.3).

1.2.5.1 Hydrocarbons in Newfoundland's Carboniferous Basins

There are numerous occurrences of bitumen, solid hydrocarbon, oil shale, and gas with traces of oily brines within the rock formations of the Bay St. George and Deer Lake basins. In many ways they are analogous to the Carboniferous basins in New Brunswick that are currently targets for shale gas production using hydraulic fracturing. The Carboniferous basins are structurally much simpler than the Green Point shale in the Humber Arm Allochthon (*see* sections 1.3 and 1.4). For that reason, this report outlining issues specific to the Green Point shale cannot be directly applied to Newfoundland's Carboniferous basins. A separate report would be required to assess their potential as unconventional hydrocarbon reservoirs.

1.3 DEFORMATION OF THE ROCKS OF WESTERN NEWFOUNDLAND

Four episodes of deformation have affected the rocks of western Newfoundland. Three are associated with the prolonged history of Newfoundland's Appalachian mountain belt, which included multiple distinct mountain-building events (orogenies). The Appalachian orogenies are named, from oldest to youngest, Taconic, Salinic, and Acadian. The even younger Alleghenian Orogeny is the only event to deform the post-Appalachian Carboniferous rocks.

1.3.1 THE TACONIC OROGENY AND ITS ALLOCHTHONS

The Taconic Orogeny was first recognized in the Taconic Mountains of New York State. This Late Ordovician episode took place about 475 to 455 million years ago. Because the Taconic Orogeny fractured, displaced, and deformed the Cow Head Group including the Green Point shale, its effects are crucial to this report. Those effects are due principally to the movement of crustal slices known as "allochthons".

Allochthons are vast bodies of rock that were formed in one place and were subsequently detached and transported by enormous geological forces, coming to rest far away from their site of origin. Gros Morne National Park, and western Newfoundland in general, are famous for allochthons that formed during the Taconic Orogeny. The Humber Arm Allochthon is centred on the Bay of Islands and the smaller Hare Bay Allochthon is centred on Hare Bay (Figures 1 and 5). Only the former is discussed further.

The Humber Arm Allochthon has two parts. The lower part of the allochthon consists of sedimentary rocks deposited in rift basins, on the continental slope and ocean floor, and during the earliest stages of the foreland basin. The upper part consists of volcanic and mantle rocks that once lay beneath the ocean floor, but were detached and pushed into place above the sedimentary rocks. Collectively termed "ophiolites", they form the Lewis Hills, Blow-me-Down Mountain, the Tablelands, and other high plateaus in western Newfoundland between the Port au Port Peninsula and Bonne Bay.

Geologists believe that the Humber Arm Allochthon traveled up to 200 kilometres or more to its present position in western Newfoundland (Figures 1 and 5). The timing of the movement is less certain. Unusual minerals found in sandstone of the foreland basin suggest the allochthon may have arrived by the Late Ordovician (about 455 to 450 million years ago). Others have argued that it happened much later, during the Devonian (about 375 million years ago). The timing of this deformation event doesn't impact the interpretation of the Green Point shale itself.

1.3.2 LATER OROGENIES

Salinic Orogeny. A Middle to Late Silurian episode, the Salinic Orogeny occurred about 420 million years ago. Evidence for it is mostly found in central Newfoundland, but there is good evidence that it also affected the rocks discussed here. Evidence for Salinic deformation comes from rocks in the western Newfoundland foreland basin and from deformed continental shelf rocks near Corner Brook, Deer Lake, and Canada Bay.

Acadian Orogeny. In the Middle to Late Devonian, about 400 to 360 million years ago, the Acadian Orogeny left its imprint throughout Newfoundland. Because it is the youngest of the Appalachian orogenies, it deforms most of the rocks found in western Newfoundland except those of Carboniferous age. In western Newfoundland, its best known feature is a set of faults. The Round Head Fault on the Port au Port Peninsula is a prominent example that features in the formation of the Garden Hill oil field discovered in 1995 (*see* Appendix B, section B.1.1). The orogeny also deformed rocks of the Humber Arm Allochthon.

Alleghenian Orogeny. Carboniferous sedimentary rocks of the Bay St. George and Deer Lake basins were deformed by repeated episodes of sideways movement along the enormous regional faults of the Cabot Fault system (Figure 5). This deformation mostly happened during the late Carboniferous and perhaps Permian age, and is associated with the Alleghenian Orogeny in North America. The strike-slip or wrench faulting formed a series of folded and steeply tilted rocks, especially close to the faults. The northern part of the Bay St. George Basin appears to have largely escaped the deformation seen elsewhere.

1.4 DETAILS OF THE COW HEAD GROUP AND GREEN POINT FORMATION

Sedimentary layers formed on the ancient Lower Paleozoic continental slope (Figures 7 and 8) are preserved in the Cow Head Group. It is well exposed on land, principally in the area from Rocky Harbour north to Parsons Pond. The Cow Head Group contains two very distinctive sequences of limestone and shale (James and Stevens, 1986). The Shallow Bay Formation is dominated by a limestone conglomerate and thinly bedded limestone, while the younger Green Point Formation is dominated by shale with minor limestone conglomerate. In between these, the sequence of rock layers is a mixture of the Shallow Bay and Green Point sequences.

1.4.1 SHALLOW BAY FORMATION

The limestone conglomerates of the Shallow Bay Formation formed on the lower continental slope (*see* Figure 7). They are particularly unusual because they include boulders and locally house-sized blocks of limestone that broke away from the carbonate platform (*see* section 1.2.3.1) at the very rim of the ancient continental margin. The boulders were eroded during storms and other damaging events, then tumbled down the slope to accumulate there. The limestone shows that throughout much of its 20-million-year history, the rim of the continental margin was made of great, robust reef-like mounds rich in sponges and algae.

1.4.2 GREEN POINT FORMATION AND ITS SHALE

The shale of the Green Point Formation formed even lower on the continental slope and on the adjacent ocean floor (Figure 7), farther away from the margin edge and in deeper water than the conglomerates of the Shallow Bay Formation. The formation is best known and best exposed from Green Point north to St. Paul's Inlet and Parsons Pond.

The shale of the Green Point Formation is commonly black and green and contains locally up to 10.4% total organic carbon (Cooper and others, 2001; Fowler and others, 1995; Hamblin, 2006), making it the principal source rock in the hydrocarbon system of western Newfoundland (*see* section 2.3). The hydrocarbon-rich shale is the main target for unconventional exploration in western Newfoundland, but the Green Point Formation also includes red and green shale that has little or no hydrocarbon potential. In addition, it contains some interbedded conglomerate, sandstone and carbonate layers, as observed along the shores of Port au Port Bay.

The Green Point Formation in Port au Port Bay and at Cow Head is generally overlain by thick successions of sandstone, conglomerate, and shale that were deposited as the foreland basin began to evolve ("Foreland basin sequence" in Figure 8; *see* section 1.2.4). Any of the known or inferred locations of the Green Point shale are a potential exploration target for shale hydrocarbons.

1.4.3 "GREEN POINT SHALE" DEFINED

The term "Green Point shale" as used in this report is a name sometimes informally given to shale layers in western Newfoundland that either are known to be, or are inferred to be, part of the Green Point Formation.

a. The Green Point Formation (part of the Cow Head Group) is formally defined by the example at Green Point, near Rocky Harbour (*see* Figure 5 and Figure 22B). The formation is known to occur extensively from Rocky Harbour to the eastern part of Parsons Pond, where it contains a variety of shale layers.

b. In the Port au Port region, shale layers occur as part of the Cow Head Group. That shale has been correlated with the Green Point Formation, but the Green Point shale as identified in the Port au Port region includes rock layers and formations that are not Green Point shale in the strict sense.

c. Shale has been encountered in exploration wells off the west coast of Newfoundland, where the Green Point Formation is also projected to occur below the sea floor, from south of Bonne Bay to Bay of Islands and into Port au Port Bay.

1.4.4 COMPLEX HISTORY OF DEFORMATION

The Green Point shale has been proposed as a target for hydraulic fracturing in western Newfoundland, and the fact that it has been deformed by multiple orogenies must be taken into account when assessing the risks of such an activity. Cross-sections illustrated in Figure 9 show the variety of complicated ways in which rock layers of the region have changed shape and moved along faults (Cooper and others, 2001). This is especially true for the rocks of the Humber Arm Allochthon (for example, *see* Figure 9b, 9c, and Figure 10). They were first deformed as they were pushed from the continental slope to their present position during the Taconic Orogeny. Then they were again folded and faulted during the Acadian Orogeny (*see* section 1.3).

Because of this long history of deformation, rock layers that were originally flat-lying and regular are now broken and distorted. Reconnaissance geological mapping of the shoreline along Port au Port Bay has shown that Green Point shale layers everywhere are tilted at moderate to steep angles – in some instances to a vertical position – because of the folding and faulting. Understanding the complex structure of the Humber Arm Allochthon in the Port au Port area is still in its preliminary stages. In the Cow Head and Parsons Pond areas too, further work is needed. But it is certain that nowhere does the structure of the Green Point shale follow the predictably simple, layer-cake style found in many other foreland basins of North America (*see* section 2.1.4).

Where visible at the surface, the Green Point shale is heavily fractured. These structures crisscross the rock layers at various angles, forming an interconnected network of weaknesses throughout the formation. The fractures are likely responsible for the leaking of hydrocarbons out of the formation to the surface, resulting in abundant seeps and shows (Figures 1 and 6). Similar leakage explains how hydrocarbons from the Green Point shale could have migrated to conventional reservoirs like the ones explored in the carbonate shelf sequence (*see* sections 2.2, 2.3, and Appendix B).

Evaluating the amount and kind of deformation and fracturing at each proposed site will be an important part of the risk assessment for any hydrocarbon exploration of the Green Point shale. The greater the abundance of interconnected crosscutting fractures, the easier it is for hydrocarbons – or any fluid – to leak out of the formation.

1.5 GEOPHYSICAL SURVEYS

Geophysical methods can "see" rock layers buried deep beneath the surface of the land or sea, penetrating glacial deposits and soil as well as hundreds of metres of water. They can also reveal large-scale geological patterns that may not be apparent from other research. For these reasons, geophysical surveys are useful in understanding the hidden geology below the surface of sedimentary basins. Techniques include reflection seismology, aeromagnetic surveys, and gravity surveys. (*See* Appendix D, Definitions, for a brief explanation of these.) Seismic and aeromagnetic data are discussed here since they are the principal tools of exploration in western Newfoundland.

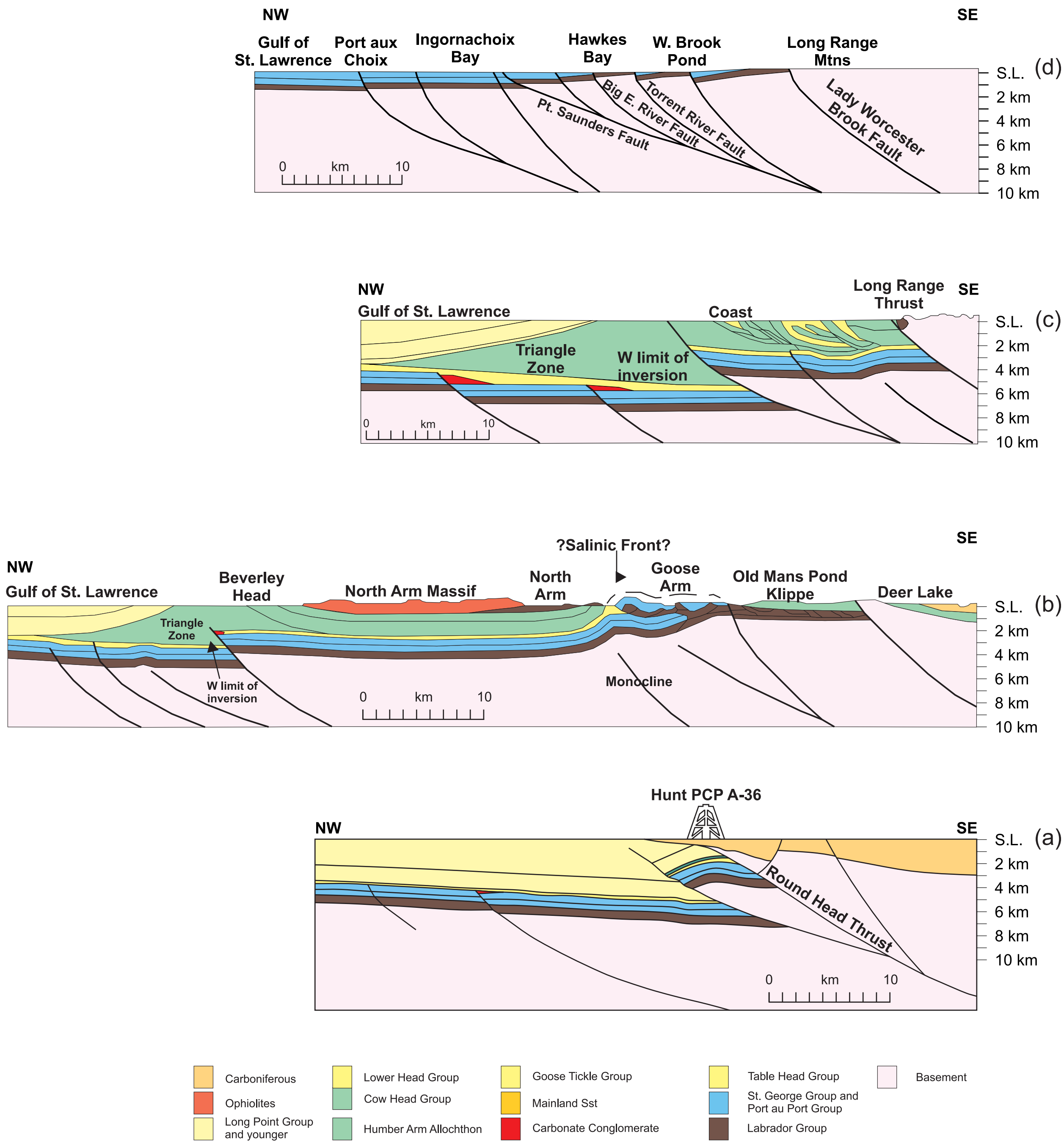


Figure 9. *Structural cross-sections through western Newfoundland. The locations of the cross-sections are shown in Figure 5. The structural style varies from one area to another:* ***(a)*** *The Carboniferous Bay St. George's Basin truncates thrusts and folds in the vicinity of Hunt PCP's St. George's Bay A-36 well.* ***(b)*** *Complex folds and thrusts locally deform the Humber Arm Allochthon.* ***(c)*** *Overlapping thrust slices control the distribution of rock units in the Parson's Pond area.* ***(d)*** *High-angle faulting involving basement rock dominates the most northerly section.* ***S.L.****, sea level. Adapted from Cooper and others (2001).*

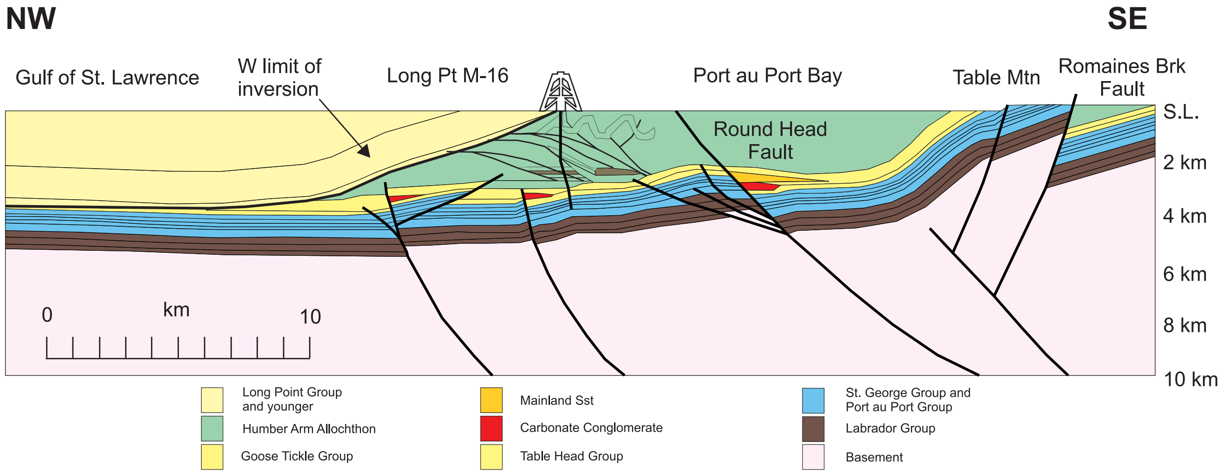


Figure 10. *Structural cross-section through Port au Port Bay. The cross-section is based on an interpretation of well data, seismic data, and surface geology; its location is shown in Figure 5. Complex fault-repeated layering occurs in the Humber Arm Allochthon below the Long Point M-16 well, which targets the underlying carbonate platform.* ***S.L.****, sea level. Adapted from Cooper and others (2001).*

1.5.1 SEISMIC DATA

Petroleum geologists and geophysicists use reflection seismology or “seismic reflection” (commonly abbreviated to “seismic”) to understand the distribution, extent, and deformation of layers in sedimentary basins, as well as to map and interpret potential petroleum reservoirs. Measurements taken along a series of survey “lines” are analyzed by computer programs to create two-dimensional (2-D) or three-dimensional (3-D) images that show patterns of seismic reflection. Because different kinds of rocks have distinctive known responses to seismic waves, the patterns can be used to identify rock layers, their thickness, and location at depth. This enables geophysicists to recognize deeply buried structures in the rock succession.

As computers have become faster and more powerful, larger and more detailed seismic surveys have become possible. In the mid 1990s, small 2-D surveys were still common; but since then large-scale, high-resolution 3-D surveys have become routine. In consequence, geologists’ understanding of sedimentary basins based on seismic surveys has improved and evolved. True 3-D seismic data have yet to be acquired in western Newfoundland (*see* Area 1 in CNLOPB, 2010). Nonetheless, sophisticated computer programs can rework 2-D seismic data into quasi-3-D models with some success, and this technique has been used for the region.

1.5.1.1 Seismic Data for Western Newfoundland

Approximately 12 000 line-kilometres of 2-D seismic data have been collected in offshore regions of western Newfoundland since 1969. Onshore, the approximately 1100 line-kilometres of seismic data provide sporadic coverage, and existing data are concentrated in specific regions, namely Parsons Pond, Port au Port Peninsula, northern St. George’s Bay and the Deer Lake area lowlands of the upper Humber River (Figure 11). Most of the seismic data were collected in the late-1980s to mid-1990s and are not up to modern standards.

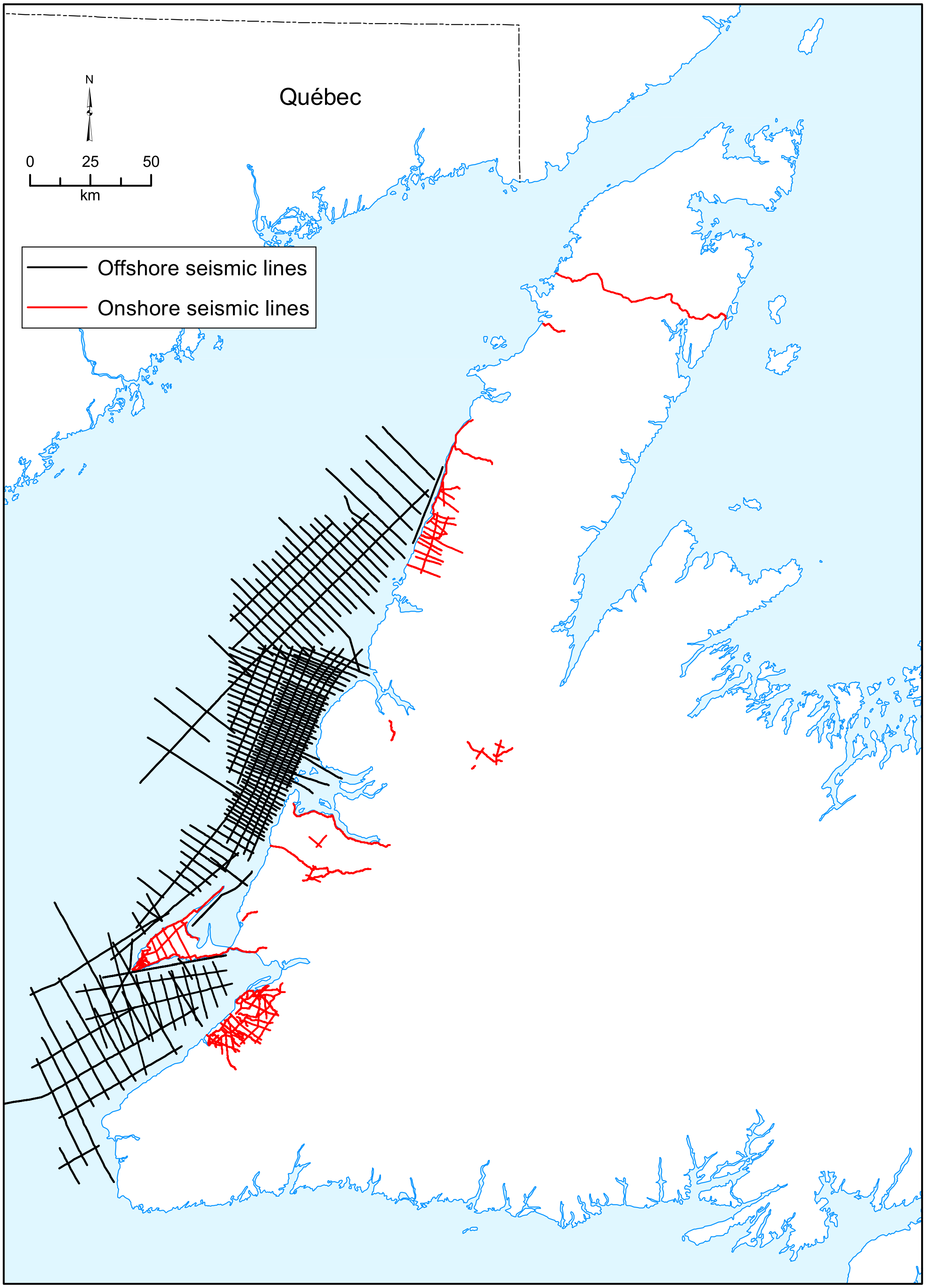


Figure 11. *Distribution of onshore and offshore seismic lines in western Newfoundland. The seismic surveys conducted in western Newfoundland represent 12 000 line-kilometres of 2-D data offshore and 1100 line-kilometres of 2-D data onshore.*

Looking at the seismic data from a regional perspective, three lines collected by Hunt Oil Company in the early 1990s illustrate the nature of the Appalachian structural front (Figure 12; *see* Figure 5 for locations). Stockmal and others (1998) noted that all images show three sets of reflections:

a. An upper set of parallel reflections, interpreted as the Late-Ordovician to Devonian foreland basin rocks. They are tilted steeply to moderately westward and are locally folded. The contact of this upper set of reflectors with the underlying Humber Arm Allochthon is interpreted as a fault known as the Tea Cove Thrust.

b. A middle, wedge-shaped set of discontinuous and ambiguous internal reflections with no marker beds, interpreted as the Humber Arm Allochthon.

c. A lower set of parallel reflections, interpreted as basement rocks overlain by Lower Paleozoic shelf and Middle Ordovician foreland basin rocks that dip consistently to the east.

As seen in Figure 12 (locations on Figure 5), the known triangular geometry of this three-part seismic package can be traced extensively in offshore seismic profiles from south to north and is known as the "Triangle Zone" (also *see* section 2.2.2).

The seismic lines terminate short of the west coast of Newfoundland at their eastern end (Figure 11), but the subsea geology, as seen in Figures 12 and 13, can be projected onshore. To the west, the Humber Arm Allochthon extends below Long Point, where seismic images show it occurs beneath Carboniferous rock layers. Wells drilled from the northern shore of Port au Port Peninsula into the Cambro-Ordovician platform carbonates first encountered undifferentiated shale. This finding confirmed that the middle package is the Green Point shale of the Humber Arm Allochthon. Some sandstone, shale, and conglomerate of the foreland basin was also transported along with the shale.

1.5.1.2 Limitations of Existing Data

Existing seismic data for the Humber Arm Allochthon allow for calculation of the overall thickness of the allochthon within the Port au Port Bay area. However, the seismic images show no distinctive regional-scale features that can be used to trace specific rock layers, folds, or faults. Rather, the structure appears to be extremely discontinuous (Rowe, 2003; also *see* Figure 13). The style of folding and faulting of the shale observed in outcrops onshore around Port au Port Bay (*see* section 1.4) is likely a good indication of the deformation that occurred at depth.

Because the available seismic data do not provide effective images of the Humber Arm Allochthon or the Green Point shale, a modern seismic program in the region would greatly improve the ability to predict where the Green Point shale occurs at depth, how the composition of the Humber Arm Allochthon varies internally, and how it was affected by regional deformation and faulting. Such higher quality data would also be crucial for designing – and predicting the effects of – an initial hydraulic fracturing program as well as any future production operations.

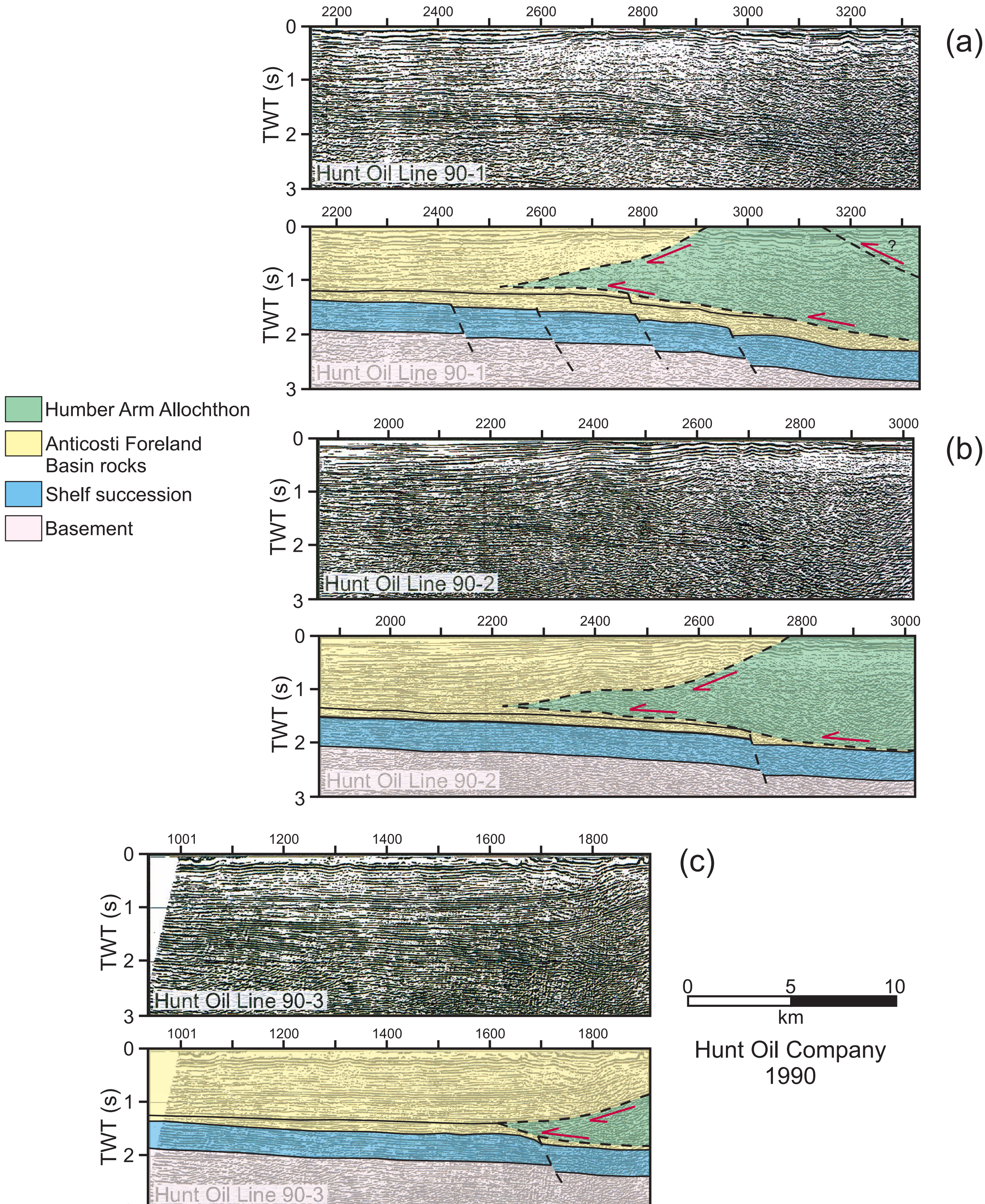


Figure 12. *Seismic cross-sections of western Newfoundland, 1990 data. The locations of the seismic lines are shown in Figure 5. Black and white panels show uninterpreted seismic data; colours depict interpreted rock formations and features. The upper 3 seconds of data are approximately equivalent to 6 kilometres in depth.* ***TWT(s)****, two-way travel time in seconds. Data from 1990 Hunt Oil Company seismic survey; adapted from Stockmal and others (1998).*

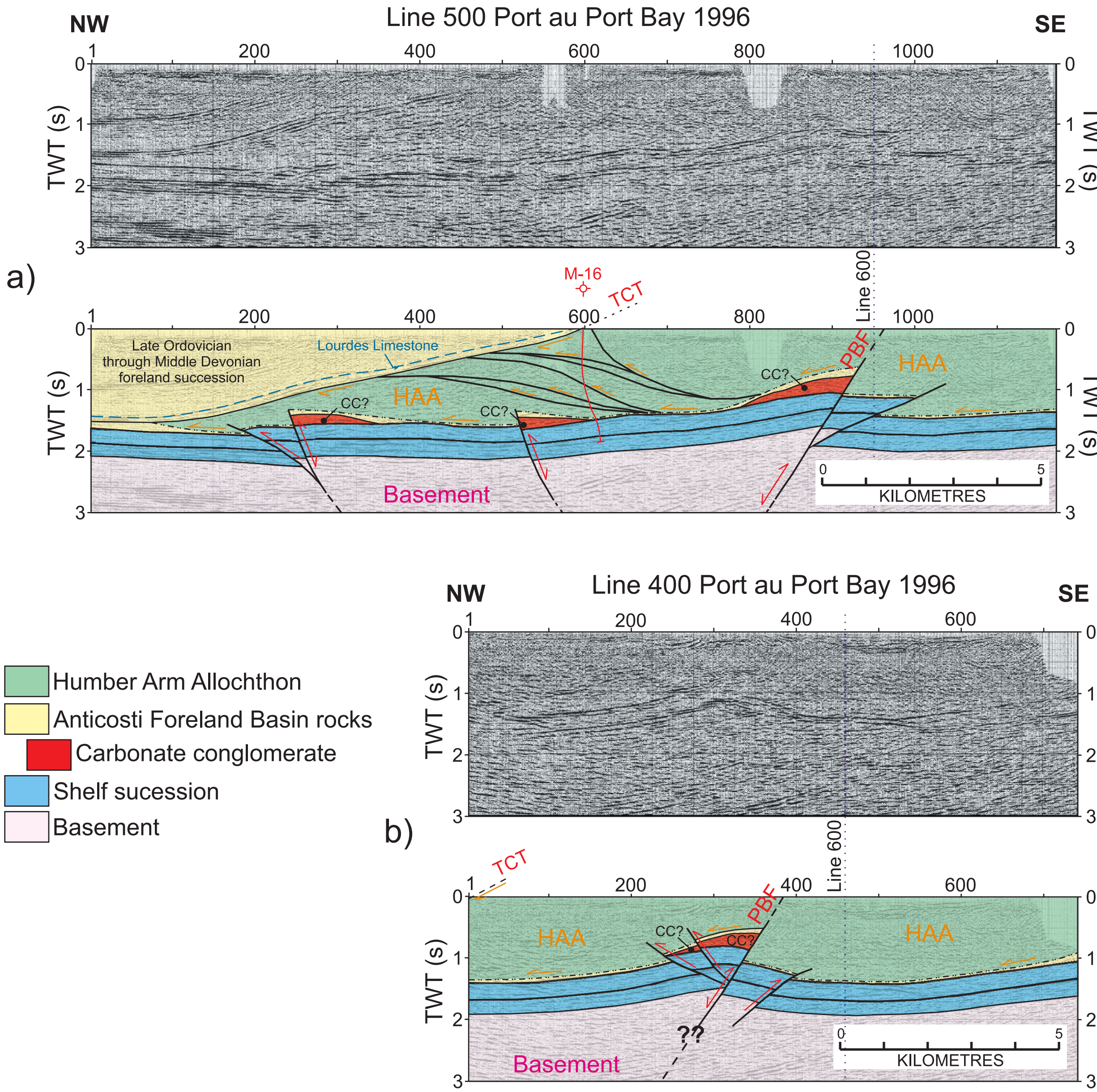
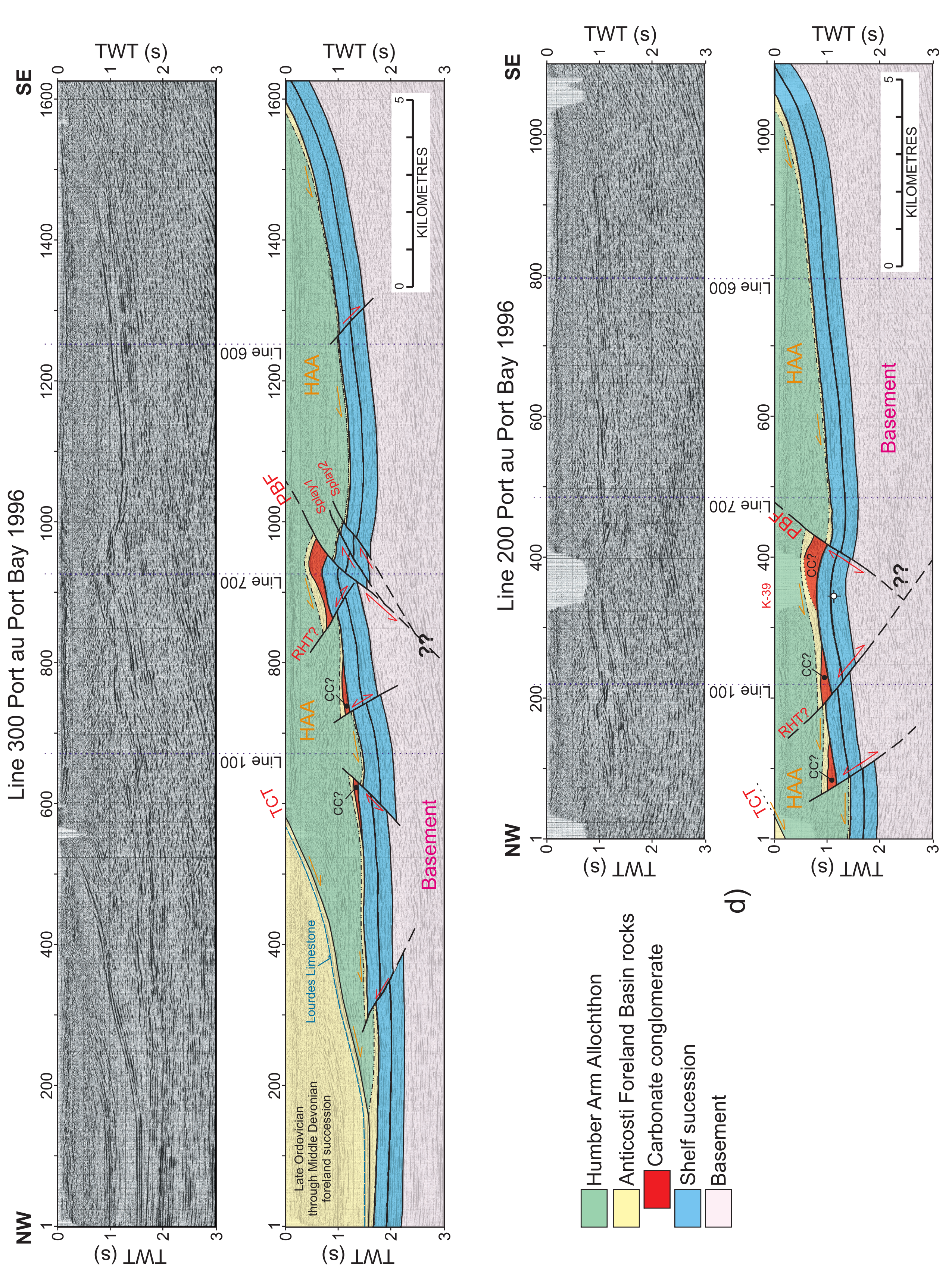


Figure 13. (This page and opposite.) *Seismic cross-sections of western Newfoundland, 1996 data. The locations of the seismic lines are shown in Figure 6. Black and white panels show uninterpreted data; colours depict interpreted rock formations and features. The upper 3 seconds of data are approximately equivalent to 6 kilometres in depth.* ***TWT(s)****, two-way travel time in seconds;* ***CC****, carbonate conglomerate;* ***HAA****, Humber Arm Allochthon;* ***PBF****, Piccadilly Bay Fault;* ***RHT****, Round Head Thrust;* ***TCT****, Tea Cove Thrust;* ***VBF****, Victors Brook Fault. Data from 1996 Hunt Oil Company seismic survey; adapted from Stockmal and others (2004).*



c)
Line 300 Port au Port Bay 1996
NW
SE
TWT (s)
Line 100
Line 700
Line 600
Late Ordovician through Middle Devonian foreland succession
Lourdes Limestone
TCT
CC?
HAA
RHT?
PBF
Splay1
Splay2
??
Basement
KILOMETRES
d)
Line 200 Port au Port Bay 1996
K-39
Humber Arm Allochthon
Anticosti Foreland Basin rocks
Carbonate conglomerate
Shelf sucession
Basement

1.5.2 AEROMAGNETIC FIELD DATA

For an aeromagnetic survey, very sensitive instruments carried on board an aircraft are used to measure small, local variations in the strength of the Earth's magnetic field. The data are analyzed by a computer program to create a map of the variations. Rocks that contain a lot of iron-rich minerals usually create a strong magnetic "signature" allowing them to be identified. Such rocks include crystalline basement rocks, volcanic rocks, and ophiolites (*i.e.*, displaced oceanic crust; *see* section 1.3.1). Sedimentary rocks generally have little magnetic response, but they can still be mapped by identifying subtle magnetic variations.

The fact that soil, glacial deposits, and vegetation are usually magnetically "transparent" makes the technique especially useful for geological mapping of areas where bedrock is not exposed. Coupled with seismic data, a magnetic survey can be used to project the onshore geology onto offshore regions by mapping similar, recognizable features and patterns across the shoreline. For example, some rock units show a characteristic magnetic pattern, and their contact with adjacent rocks can be inferred where the magnetic pattern changes. Similarly, the existence of a fault can be defined by a linear magnetic trend, or its presence can be inferred by the obvious offset of magnetic features or patterns.

1.5.2.1 Detailed Aeromagnetic Surveys

New, detailed aeromagnetic surveys were conducted in onshore and offshore areas of western Newfoundland in 2009 and 2012, respectively (Figures 14 and 15). Onshore, more than 60 000 line-kilometres of data were collected in 2009 over a large contiguous area in western Newfoundland. The survey was funded by the Petroleum Exploration Enhancement Program and the Geological Survey of Newfoundland and Labrador, and data are available through the survey's website.

The high resolution 2012 survey covers most of the offshore of western Newfoundland, overlaps with the onshore survey, and includes onshore areas not previously flown, such as the Port au Port Peninsula and Flat Bay areas. The offshore survey was carried out under the Offshore Geoscience Data Program and was managed by the Geological Survey of Canada under a letter of agreement with the Province. It will be very useful for understanding hydrocarbon reservoirs in the region.

To obtain both surveys, aircraft flew a regular pattern of northwest-to-southeast flight lines spaced 200 metres apart over land and shallow water and 400 metres apart over deep water farther from shore. To assist in processing the data, lines were also flown southwest to northeast every 1500 metres. Each aircraft was equipped with three magnetometers to provide information about how quickly the magnetic properties changed, both vertically and horizontally. This is called the "magnetic gradient" and is important for identifying subtle trends and patterns in sedimentary layers near the surface.

1.5.3 FEATURES IDENTIFIED BY THE SURVEY

The most obvious features on the aeromagnetic map are several strongly magnetic areas that form a continuation of the ophiolites mapped onshore in the Bay of Islands area (Figures 14 and

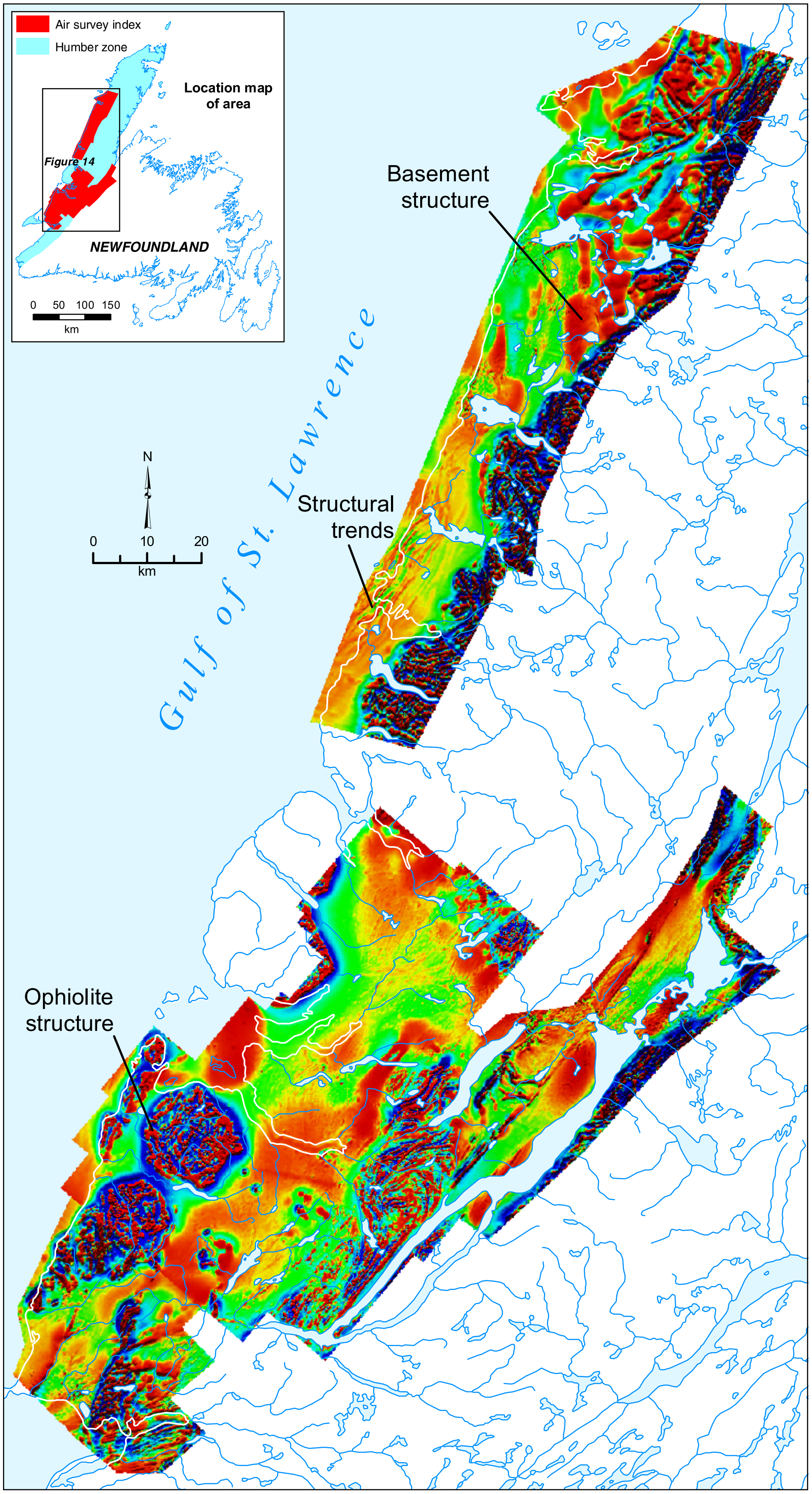


Figure 14. *Recent aeromagnetic survey data for western Newfoundland. The map shows variations in the first vertical derivative of the magnetic field. The first vertical derivative is a computer-calculated factor that emphasizes near-surface features.*

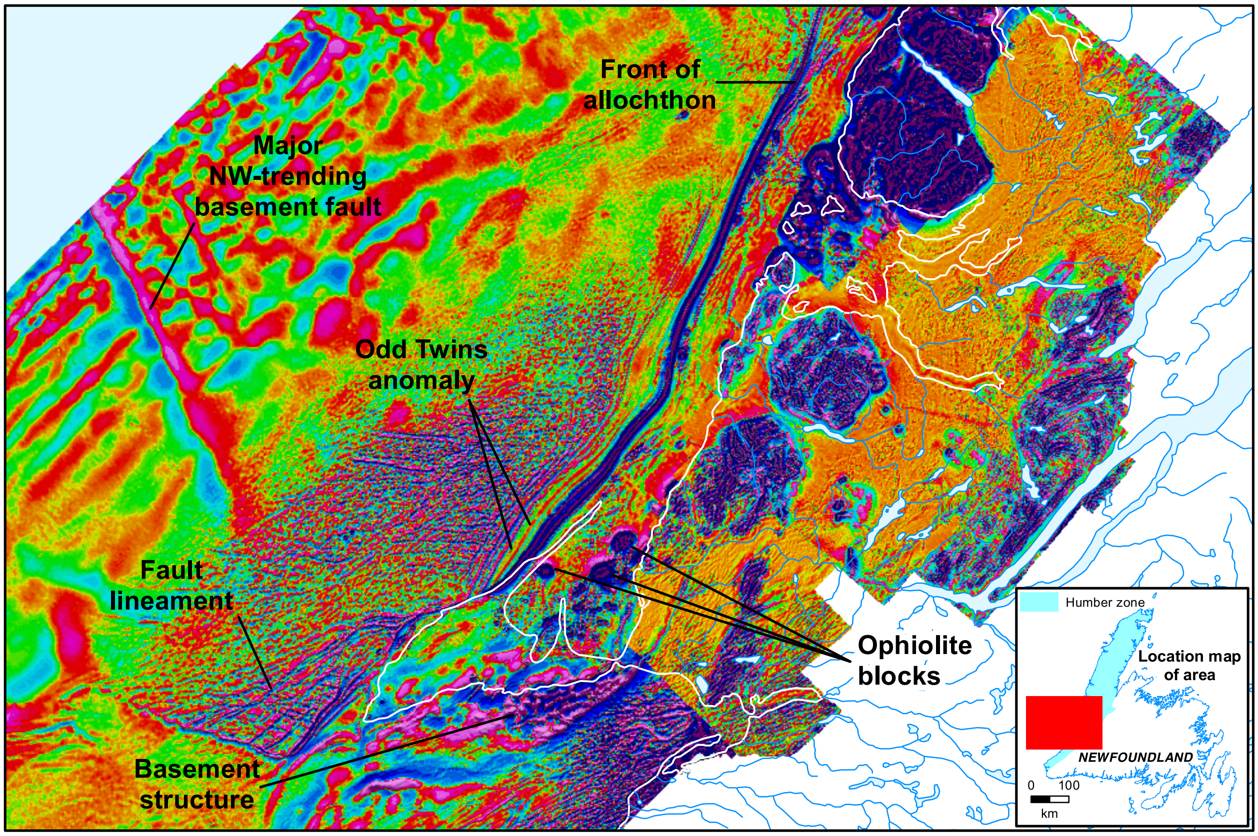


Figure 15. *Regional aeromagnetic map of western Newfoundland. The map shows variations in the second vertical derivative of the magnetic field. The second vertical derivative is a computer-calculated factor that emphasizes subtle variations in the magnetic field that highlight contacts between geological features. Note the onshore and offshore faults as well as basement areas and ophiolite blocks. Linear features trending northeast-southwest in offshore areas likely reflect the bedding trends of sedimentary rocks in the Anticosti Basin.*

15). Several large and small circular anomalies are seen both in Port au Port Bay and at depth along the shoreline. They are believed to be ophiolite blocks, although the rocks are mapped as sediments of the Humber Arm Allochthon (Figure 15). Overall, the aeromagnetic data emphasize that the rock layers below the surface are more complicated and contain a greater variety of rock types than previously recognized.

In general, seismic lines (Figure 11) for western Newfoundland reveal very few features – sometimes none at all – that can be reliably followed for any distance within sedimentary rocks of the Humber Arm Allochthon. This may be because the allochthon's typically thin, discontinuous layers of alternating sandstone, shale, and limestone cannot provide any strong, well-defined seismic reflections. In addition, deformation has tilted the layers, and steeply tilted layers are poorly detected by 2-D seismic surveys. Deformation within the allochthon also makes it difficult to trace broken and distorted layers and difficult to discern or predict where any one layer occurs.

On the Port au Port Peninsula, several visible faults oriented northeast–southwest or north–south cut rocks of the Lower Paleozoic carbonate platform. These can be traced for some distance into Port au Port Bay using enhanced aeromagnetic data (Figure 15), even though several of these faults cannot be mapped with confidence in the overlying Humber Arm Allochthon rocks onshore. Strong linear features oriented nearly north–south occur in East Bay, and from these it is possible to project the Piccadilly Bay Fault northward dissecting Port au Port Bay as proposed by Stockmal and others (2004). The structure within the bay, however, may be much more complicated than previously shown because the magnetic data indicate that there are several similarly oriented faults that have not been identified previously.

1.5.4 GEOPHYSICAL DATA FOR THE ANTICOSTI BASIN

The Anticosti Basin formed as a foreland basin north of the Appalachian Mountain belt in Newfoundland and Quebec (*see* section 1.2.4); it is centred on the northern Gulf of St. Lawrence. Foreland basin rocks are being targeted for hydrocarbon exploration in other parts of North America (*see* section 2.1.4).

Seismic lines over the Anticosti foreland basin sediments immediately west of Port au Port Peninsula show a layered stratigraphy. Several nearly horizontal, strong seismic reflectors can be reliably mapped from one seismic line to the next throughout the basin. A seismic line along the axis of the basin shows that it shallows to the north and west and that successively older sedimentary units have been eroded on or near the surface of the sea floor.

Based on the offshore aeromagnetic surveys, a series of alternating bands (high and low magnetic signature) suggests that the sedimentary layers in the basin are tilted and aligned east–west or northeast–southwest (Figure 15). Only along the eastern margin of the foreland basin are the rocks deformed significantly, where they are in contact with the Humber Arm Allochthon. Approaching this contact, the foreland basin sediments are warped up, as observed along Long Point, Port au Port Peninsula, and on seismic images of offshore areas. Several parallel, north-northeast-trending magnetic trends can be observed in the magnetic data, from Long Point into the offshore as far north as the mouth of Bonne Bay. Two relatively strong magnetic markers named the Odd Twins Anomaly coincide with two units of sandstone rich in magnetic mineral grains.

In summary, 2-D seismic data show that the layer-cake stratigraphy of the Anticosti Basin and of the underlying rocks of the Lower Paleozoic carbonate platform within and west of Port au Port Bay contrasts strongly with the opaque, essentially non-reflective rocks of the adjacent, strongly deformed Humber Arm Allochthon. Magnetic data show that ophiolitic rocks are more extensive in the offshore than previously recognized.

(This page intentionally left blank)

2. HYDROCARBON RESOURCES OF WESTERN NEWFOUNDLAND

Hydrocarbon exploration in Newfoundland has a long history dating back to the early 1800s. It has included the search for conventional and, more recently, unconventional reservoirs of oil and gas. This section provides some background information about hydrocarbon reservoirs and describes the geological context of unconventional shale reservoirs (2.1). It reviews the history of hydrocarbon exploration in western Newfoundland (2.2) and outlines the petroleum geology of the region (2.3).

2.1 BACKGROUND INFORMATION

A specific reservoir of hydrocarbons with a consistent, defined set of geological characteristics is often called a “play”. Hydrocarbon reservoirs are classified as “conventional” or “unconventional” (*see* Table 1 and Figure 2) depending on the characteristics of the rock in which they occur and how the hydrocarbons would need to be extracted. Within the reservoir, hydrocarbon accumulations, whether oil or gas, have other characteristics affecting the value and feasibility of any eventual production from the play.

Exploration for unconventional hydrocarbon reservoirs in western Newfoundland takes place within the context of a significant effort in North America to explore, develop, and produce oil and gas from shale reservoirs. The new drilling technologies required for unconventional hydrocarbon operations were first applied to the Barnett shale in northeast Texas beginning in the 1980s. Since then, the expansion of innovative drilling techniques to exploit tight, hydrocarbon-rich shale formations has been applied to many other areas throughout North America (Figure 16). Unconventional reservoirs in North America tend to occur in foreland basins and have similar geological attributes. This section briefly reviews the basics of hydrocarbon exploration.

2.1.1 CONVENTIONAL RESERVOIRS

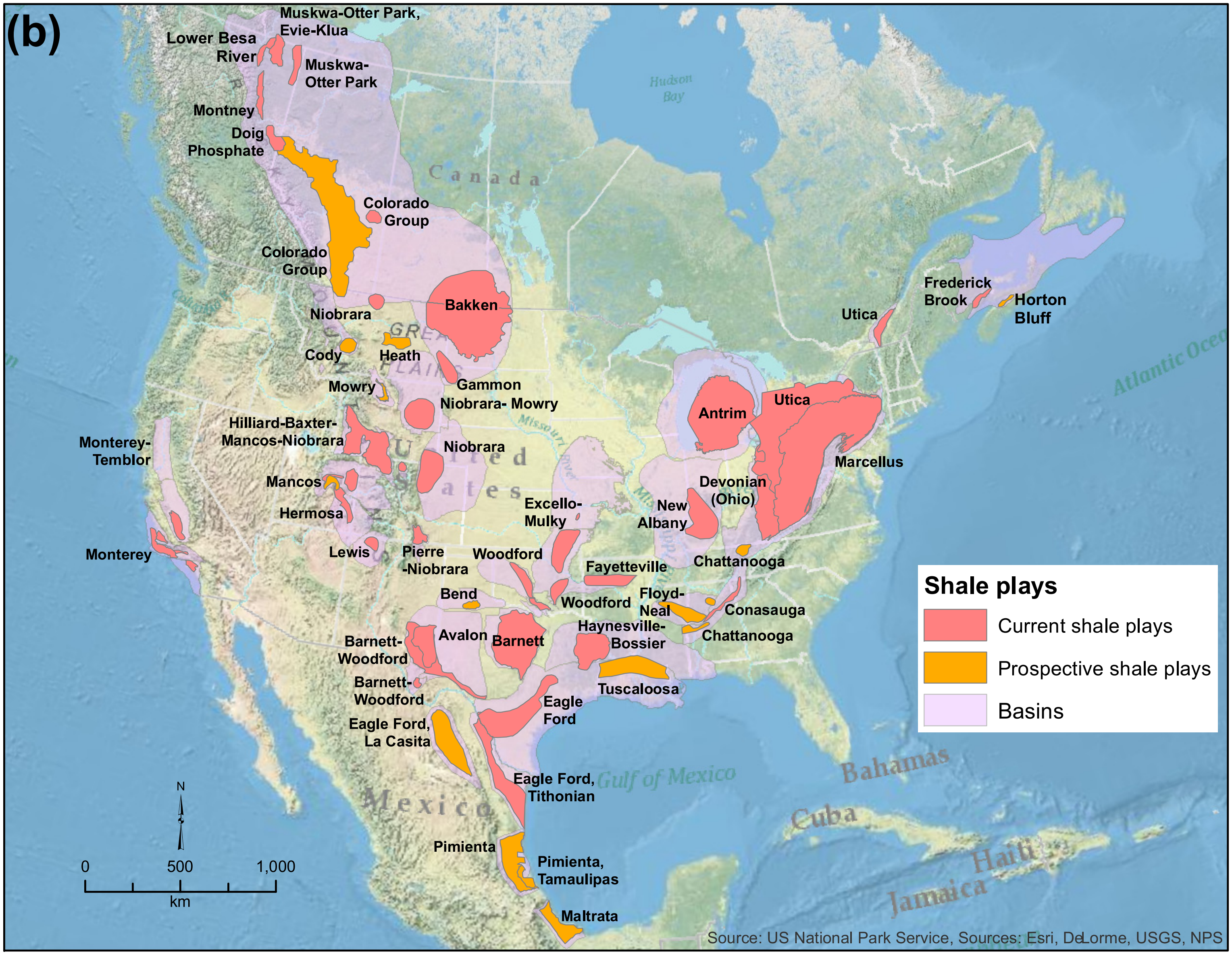
In conventional reservoirs, layers of sandstone and carbonate contain the hydrocarbons in interconnected pore spaces that allow flow of the hydrocarbon through the rock and into the well. Like water in a kitchen sponge, the hydrocarbons in the pores can move from one pore to another through smaller connections between the pores. The connections allow flow through the reservoir, and a measure of this flow is called “permeability”.

The oil or gas in conventional plays flows principally from nearby organic-rich shale (source rocks). It then accumulates in porous, permeable sandstone or carbonate (reservoir rocks) and is prevented from escaping by impermeable layers above the reservoir (trap, seal, or cap rocks).

2.1.2 UNCONVENTIONAL RESERVOIRS

Unconventional reservoirs occur in rock formations with low permeability (called “tight” formations) that can range from sandstone to carbonate, coal, or shale. Typically shale gas is the target, although oil is also recovered from some shale plays (for example, the Bakken Formation of the

Figure 16a. *The main sedimentary basins of North America. Tx-La-Ms, Texas-Louisiana-Mississippi. Modified from U.S. Energy Information Administration (2011).*



Source: U.S Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.

Figure 16b. *The main North American shale plays. Modified from U.S. Energy Information Administration (2011).*

Williston Basin of North and South Dakota and southern Saskatchewan; *see* Figure 16a). Because of the low permeability of tight formations, the hydrocarbon cannot flow out of them unless permeability is created artificially, for example, by hydraulic fracturing linked with "horizontal" drilling of wells.

There are three basic types of unconventional reservoir:

a. **Tight gas or tight oil reservoirs.** These reservoirs occur in low-permeability sandstone or siltstone and carbonate reservoirs, the hydrocarbons having migrated into the reservoir from an adjacent source rock over millions of years.

b. **Coal-bed methane reservoirs.** Coal seams that occur at relatively shallow depths act as both source and reservoir for natural gas. Coal seams explored for coal bed methane are mostly shallow, as coal is physically too weak to maintain porosity when it is deeply buried. It is not uncommon for coal bed methane reservoirs to lie below nearby underground sources of drinking water. Hydraulic fracturing is restricted in such cases in most jurisdictions.

c. **Shale gas or shale oil reservoirs.** Some low-permeability shale formations are rich in organic carbon. They contain natural gas or oil, which is either trapped in large-scale porosity features such as fractures, held in isolated small-scale pores, or adsorbed onto minerals or onto organic matter within the shale. In such plays, the shale is the source, the reservoir, and the seal or cap rock all in one.

2.1.3 OTHER RESERVOIR CHARACTERISTICS

The hydrocarbons contained in rock formations have a variety of characteristics that are used to describe and evaluate them. Total organic carbon measures the carbon content as a percentage of rock weight. Values of 0.5% are considered very low, and 10% is considered very good. A scale developed by the American Petroleum Institute is also used to describe the density of liquid petroleum. The scale is called "API gravity" and is measured in degrees. Most values fall between 10° (more dense) and 70° (less dense).

Sometimes oil is described as "live oil" or "dead oil". Live oil contains dissolved gases (volatiles) and has to be handled with care to prevent explosive accidents; dead oil has little or no dissolved gas. Another contrast is between "wet" and "dry" gas. Dry gas is composed almost entirely of methane, but wet gas contains a significant amount of hydrocarbon compounds heavier than methane (such as ethane, propane, and butane). The wet gas mixture may be gaseous or both liquid and gaseous in the reservoir. The heavier hydrocarbons can be condensed when brought to the surface and are frequently separated as natural gas liquids.

One important aspect of unconventional resource development is determining the potential for natural gas liquids. The recovery of an associated liquid (*i.e.,* a wet gas), rather than a dry gas, is economically more valuable. The amount of water recovered along with the hydrocarbon is often an important criterion in an unconventional reservoir, and this characteristic can be related to the amount of water present in the source rock.

Hydrocarbon resources are generated from kerogen, a form of naturally occurring organic matter. The kerogen may be Type I (mostly derived from algae), which mostly produces oil; Type II (a mixture of marine and land-based organic material), which produces a waxy oil; or Type III (derived from woody, land-based material), which produces gas and sometimes coal. Type IV is a residue with no potential to create useful hydrocarbons.

The conversion of kerogen to hydrocarbon requires a specific temperature range, and the thermal maturity of a source rock or reservoir describes the temperatures it has been exposed to while buried deep in the Earth. Below 60°C, a source rock or reservoir is considered immature. Temperatures of 60–160°C are considered ideal for the creation and migration of oil; this range is known as the "oil window". Above 160°C, a source rock or reservoir is considered overmature; gas is anticipated rather than oil and the rock is said to be in the "gas window".

Thermal maturity is determined using a combination of techniques including geochemical measurements of samples and computer models of the sedimentary basin. Other techniques use the colour change in various kinds of fossils, caused by thermal alteration as temperatures rise with increasing burial. The type of organic matter in the rock and the environment in which the sediment was originally deposited can be investigated using biomarkers – complex organic molecules that can also indicate thermal maturity. The thermal maturity of a source rock can be used as an indicator of its hydrocarbon potential.

Pyrolysis (thermal cracking) is a process in which organic material breaks down at high temperatures in the absence of oxygen. Pyrolysis typically occurs under pressure and at temperatures above 430°C. A widely used analytical system, Rock Eval, uses pyrolysis to determine the petroleum potential of a sample using standard set of measurements. *See* Table 2 and Appendix D, Definitions, for details of the measurements.

Although much of the information about hydrocarbon systems and reservoirs comes from laboratory tests, important information can also be gathered from a range of geological, geophysical,

Table 2. Information provided by Rock Eval analyses

Output	Based On	Significance
S1 peak	Hydrocarbons released during first stage of heating	Amount of free hydrocarbons
S2 peak	Hydrocarbons released during second stage of heating	Hydrocarbon potential
S3 peak	CO_2 trapped during heating	Oxygen level in kerogen
Tmax	Temperature at which S2 reaches its maximum	Thermal maturity
TOC	Residual carbon plus released carbon	Hydrocarbon potential, thermal maturity
HI	Calculation, S2/TOC	Kerogen type
OI	Calculation, S3/TOC	Kerogen type
HI *vs* OI	Plot of the two indices	Kerogen type; thermal maturity

Note: TOC - total organic carbon; HI - hydrogen index; OI - oxygen index.

and geochemical well logs. A well log, also known as borehole log, is the detailed record of the rock formations intersected by a borehole. The log may be based either on samples brought to the surface (geological logs) or on physical measurements made by instruments lowered into the hole (borehole geophysical logs or wireline logs). Well logging can be done during any phase of a well's history, *i.e.,* when drilling the well or preparing it for operations, during production, or when closing it off for temporary or permanent abandonment.

Table 3 summarizes a variety of common wireline log measurements. They are usually used in combination and sometimes also correlated to lithological or mud logs to infer the location of rock layers and other relevant characteristics encountered in the well. Mud logs are made using the "mud" or slurry of rock chips and drilling fluid that comes out of the wellbore during the drilling process.

Table 3. Types of well logs and what they measure

Log Type	Characteristic Measured
Resistivity	Water volume in both clay and pores
Density	Mineral and fluid content
Neutron	Clay and gas content
Sonic	Clay and gas content
Gamma ray	Clay and organic material volume
Electrical images	Natural and man-made fractures, pyrite, calcite nodules, and other geologic features
Spectroscopy	Organic carbon content, clay and carbonate minerals

Note: Modified from Johnson (2004).

2.1.4 UNCONVENTIONAL SHALE RESERVOIRS IN THE FORELAND BASINS OF NORTH AMERICA

On the Earth's surface, large volumes of sediment tend to accumulate in basins – areas of the Earth's surface that are at relatively low elevation compared to their surroundings. Sedimentary basins form in a variety of ways – for example, in rift valleys or along certain types of continental margins – but the majority of the unconventional shale gas or oil resources currently being explored and developed occur specifically in foreland basins.

Foreland basins form beside major mountain fold belts, on the continental interior away from the site of plate collision. In North America, there are three fold belts: the Appalachians in eastern North America, the Alleghenian fold belt of the southern United States, and the Rocky Mountain fold belt along the western side of North America. Each has associated foreland basins. *See* Figure 16a for the locations of major North American sedimentary basins.

2.1.4.1 How Foreland Basins Form

The topographic depression of a foreland basin is created when continental crust thickens along continental margins during plate-tectonic collisions. Over hugely protracted periods of time, the crust thickens as the continental margin is folded, faulted, and thrusted. Sedimentary deposits from the nearby ocean floor, portions of the sea floor itself, volcanic islands, and sometimes other continents may be pushed onto the continental margin, adding mass to the growing mountain belt (*see* Figure 4c). Rocks can become metamorphosed and huge volumes of granite can form deep in the thickening crust.

The continental crust is forced downward by the weight of the thickening mountain belt to form a huge depression in the adjacent foreland. Imagine the mountain belt is like a person standing on the end of a diving board. The board bends down, and the feet of the person lie below the fixed end of the board, essentially forming a depression. A person on a trampoline provides a similar analogy.

The deep depressions formed in this way are almost always flooded by an ocean, a sea or a lake. This makes them ideal, deep-water basins in which sediment eroded from the adjacent mountain belts is trapped and deposited. Organic material settles with the sediments, producing thick, widespread deposits of organic-rich mud. After compression, these become thick layers of shale lying deep in the basin. Layers formed in this way can often be traced for hundreds of kilometres – not only parallel to the edge, or front, of the mountain belt but also away from the front into the continental interior.

Note that in some older basins, such as the Williston Basin (which contains the Bakken Formation) and most of the Paleozoic portions of the Western Canadian Basin, sediment deposition and basin formation continued for several hundred million years. In such cases of very protracted history, sedimentation may begin in one type of setting, for example, a continental margin, and then continue as a foreland basin.

2.1.4.2 Layered Geology of the Basins

The characteristics of sedimentary rock layers vary within a foreland basin. For example, the basins become shallower with increasing distance from the mountain front. Close to the front, sediments can accumulate in thick layers and be deeply buried, but in more distant, peripheral areas of a basin the layers are thinner. A basin's sedimentary rock layers are generally only exposed on the surface at the far edge of a basin or along the mountain front where the near edge of the basin may have been later uplifted and eroded. (This has occurred in western Newfoundland; *see* section 1.5.4.) The geological conditions for most currently exploited, unconventional hydrocarbon plays are found in the essentially undisturbed, interior expanse of a foreland basin, away from the mountain range.

A favourable geological property of the sedimentary rock layers in most foreland basins is their nearly horizontal or gently dipping orientation (angles of 0–7°) that can be traced for large distances (hundreds of kilometres) in all directions within the basin. This makes for a predictable layered stratigraphy within a basin, where layer A is always followed by layer B, layer C, and so on as the succession is examined from bottom (oldest rocks) to top (youngest rocks). Seismic surveys (*see* section 1.5) allow exploration geologists to map the rocks below the surface. If the sequence of rock layers in one part of the basin is known from deep exploration wells, seismic reflections from the known layers can be correlated to others at a distance. The persistent, nearly flat layering allows a degree of confidence in predicting the character and depth of a target layer, reducing the risks of developing the plays in spite of their unconventional character.

There are some instances of unconventional resources being exploited in areas where the foreland basin layers are deformed. For example, in the Rocky Mountains of western Canada there are significant hydrocarbon discoveries in more disturbed areas close to the mountain front, including large natural gas discoveries in northern British Columbia and neighbouring areas. Similar examples can be found in the Appalachian fold-and-thrust belt, for example, the very productive Marcellus shale. In these cases the layers were usually deformed in a very simple way by a single geological event.

Because there has been a significant history of exploration and well drilling in those areas, the geology is documented in more detail compared to western Newfoundland. Well logs and seismic data are used to accurately predict the location of the target layers. In contrast, the allochthon of western Newfoundland has experienced multiple deformation events in several separate episodes of mountain building; and there has not been the same level of exploration or drilling (*see* section 1.3).

The predictability of deeply buried, gently dipping shale formations bound by other known rock formations is another favourable characteristic of North America's unconventional shale reservoirs (*see* Figure 16b for their locations). In the Appalachian basins of Pennsylvania and New York, the Marcellus shale is bound by limestone below and an unproductive shale above. The Barnett shale of Texas is bound by limestone formations above and below, as are the Mancos shale and Lewis shale of the San Juan Basin in New Mexico, the Bakken Formation of the Williston Basin in the Dakotas and southern Saskatchewan, and the Muskwa Member shale of northeast British Columbia.

2.1.4.3 Advantages for Hydrocarbon Exploration

Foreland basins have a long history of hydrocarbon exploration using conventional techniques. This exploration history provides a huge pool of geological knowledge and data that make locating and developing unconventional resources substantially predictable. Literally thousands of well logs and many tens to hundreds of thousands of kilometres of good-quality seismic lines are available for evaluating and planning future exploration programs in these basins. This level of exploration has not occurred yet in western Newfoundland (*see* section 2.2). The presence of these basins; however, does provide the prospect of both conventional and unconventional resources.

The gas trapped in such foreland basin shales is generally dry (*i.e.*, 90% or more methane), but some formations do produce wet gas. In addition, some shallower basins in Illinois and Michigan (which include the Devonian Antrim shale and New Albany shale) yield gas that is also characterized by substantial amounts of water (up to 500 barrels per day per well). Although water was once a significant part of the original organic-rich mud, much of the water is typically squeezed out during compaction and rock formation.

2.2 EXPLORATION HISTORY IN WESTERN NEWFOUNDLAND

This section briefly reviews the history of petroleum exploration efforts in western Newfoundland. For further details, *see* Appendix B for a region-by-region account of exploration in the southern, central, and northern Anticosti Basin as well as Newfoundland's Carboniferous basins.

2.2.1 HISTORICAL PETROLEUM EXPLORATION (PRE-1994)

For more than a century, seeps and shows of live and dead oil, gaseous emissions, and oily odours have been noted coating or emanating from the sedimentary rocks of western Newfoundland, both in surface rocks (outcrops) and in drillcores and cuttings (*see* Figures 1 and 6). In 1812, oil collected from seeps along the shore of Parsons Pond was prized as a cure for rheumatism. Since that time the role of hydrocarbons and knowledge about their distribution in western Newfoundland have evolved dramatically. This brief summary of the early history is based on an account in Fowler and others (1995). Additional historical information can be found in reports by Fleming (1970), Newfoundland and Labrador Petroleum Directorate (1982), Newfoundland and Labrador Department of Energy (1989), and Newfoundland and Labrador Department of Mines and Energy (2000).

The first documented attempt at drilling a well occurred on the south shore of Parsons Pond in 1867. The well was drilled to a 213-metre depth and reportedly encountered oil and gas; however no further drilling was attempted at that time. A second well was successfully drilled at Parsons Pond in 1895 and numerous additional wells were drilled for hydrocarbons in that area before 1925. It is reported that up to four wells were in production at one time during the 1920s.

J.P. Howley was the first to describe oil seeps in the Shoal Point area of the Port au Port Peninsula in 1874. Wells drilled at Shoal Point from 1898 to 1901 had production up to 20 barrels (*i.e.*, 3.18 cubic metres) per day, but no further information is available on the wells or their operations.

Following World War II, sporadic exploration continued to persue economic hydrocarbon resources in the region. These included wells in the Deer Lake region in 1955, near Flat Bay in 1957, and the Anguille Mountains in 1973. In 1965, Golden Eagle Refining Company of Canada drilled two wells on Shoal Point. Cores were obtained from selected intervals. The Shoal Point #1 well encountered rocks with limited porosity, and the cuttings (samples of rock from the well) exhibited only minor to trace amounts of oil staining and fluorescence (fluorescent properties of oil are used while drilling to detect oil in the core and cuttings). Shoal Point #2, a few kilometres to the south, penetrated numerous zones with live and dead oil shows described as varying from "trace" to "good".

2.2.2 RECENT PETROLEUM ACTIVITY (1994–2013)

This era of exploration can be divided into two phases:

(a) An early phase involving several large- to medium-sized exploration companies headquartered in Calgary and Houston. This included Hunt Oil, PanCanadian (now Encana), BHP Petroleum Ltd., Talisman Energy, Marathon Oil, Mobil Oil Canada Properties, Norcen Energy (now owned by Anadarko Petroleum Corp.), and Encal Energy.

(b) The later phase of exploration involving small exploration companies, many with a local presence, such as Canadian Imperial Venture Corp., Inglewood Resources, Deer Lake Oil and Gas, Tekoil, PDI Production Inc., Enegi Inc., Ptarmigan Resources, Vulcan Minerals, Investcan Energy, Contact Exploration, Shoal Point Energy Ltd., and Black Spruce Exploration Corp. among others.

Renewed interest in the hydrocarbon potential of western Newfoundland followed the publication of Stockmal and Waldron's (1990) landmark re-examination of vintage, very poor-quality offshore seismic data. This happened at the same time as two comprehensive field workshops in western Newfoundland, which showed the region to researchers and petroleum geologists. The workshops were led by geologists of Memorial University and the Geological Survey of Newfoundland and Labrador.

Stockmal and Waldron (1990) defined the presence of the structural "Triangle Zone" in western Newfoundland (*see* section 1.5.1.1). The zone is similar to one known in the foothills of the Rocky Mountains of Alberta, where Canadian and international oil companies successfully exploit both oil and gas resources. The workshops presented for the first time a comprehensive field study of the Lower Paleozoic sedimentary rocks of western Newfoundland and showed that the area included all the elements favourable for an oil play – namely reservoir rocks, source rocks, and suitable structures in which to trap hydrocarbons.

Following these studies, Hunt Oil Company (later Newfoundland Hunt Oil Company Inc.) conducted seismic surveys both on the Port au Port Peninsula and offshore in the Gulf of St. Lawrence. The surveys showed the presence of large, potential structural traps both onshore and offshore. Onshore, their Port au Port #1 well struck oil and gas at approximately 3350 metres.

A detailed account of post-1990 exploration is provided in Appendix B. A list of recent petroleum wells in onshore and offshore areas of western Newfoundland is given in Table B.1, and the locations of recent wells are plotted in Figures 5, 6, and 17. Exploration has concentrated on a number of areas in western Newfoundland. These include the Cape St. George area of Port au Port Peninsula, Shoal Point on Port au Port Peninsula, and the Parsons Pond area of the Great Northern Peninsula. Additional exploration has occurred, but without success, in other parts of the Port au Port Peninsula, near Stephenville, and in the Bay of Islands area.

2.3 PETROLEUM GEOLOGY OF WESTERN NEWFOUNDLAND

Western Newfoundland contains at least two petroleum systems, or "fairways", with contrasting properties. This section reviews data available from existing reports of samples and wells, focusing on the Port au Port region and particularly on information of relevance for the Green Point Formation and its shale.

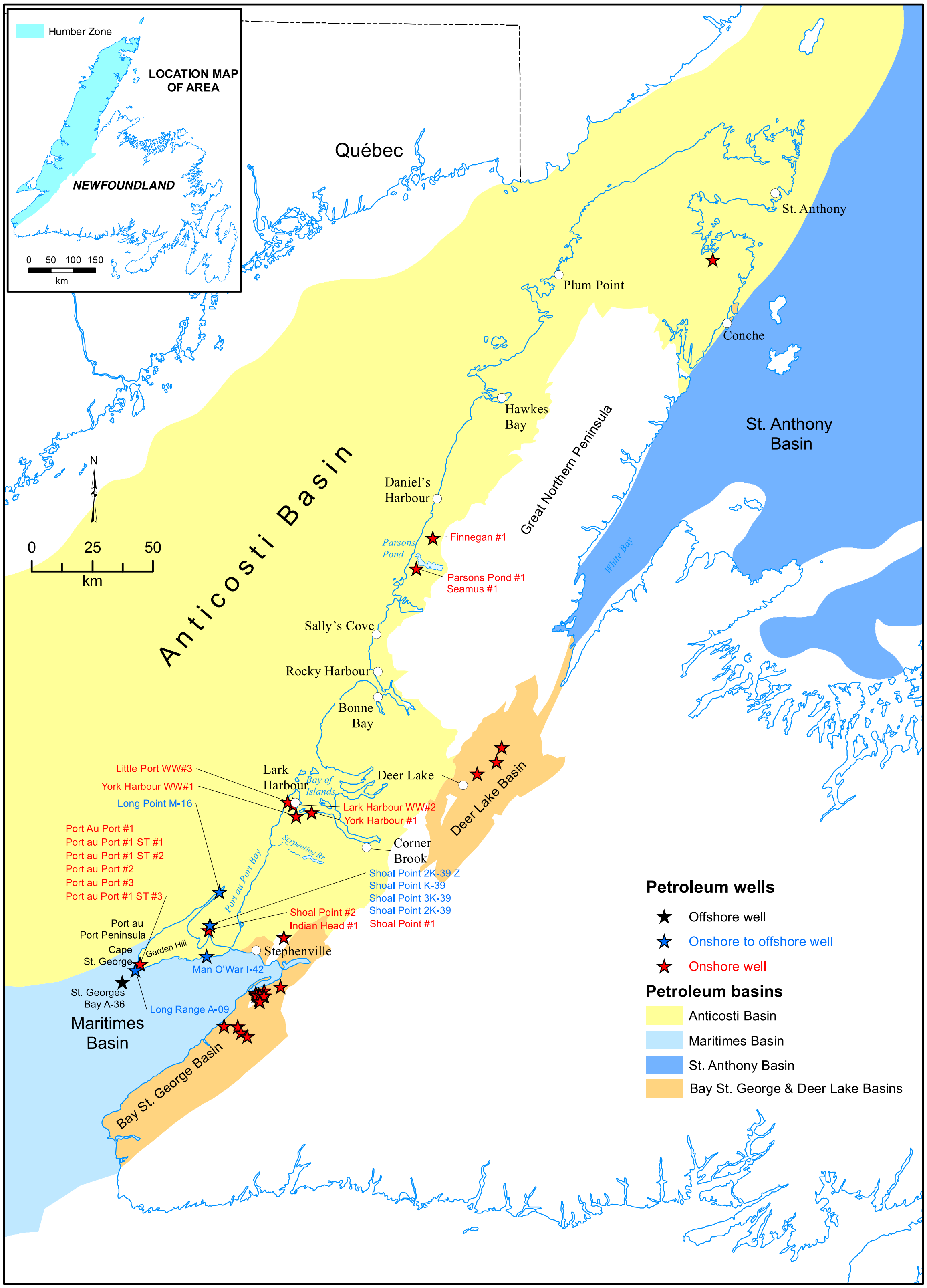


Figure 17. *Locations of post-1991 onshore exploration wells in western Newfoundland. Onshore and offshore petroleum basins of western Newfoundland showing the locations of hydrocarbon wells in the region's Anticosti and Carboniferous basins.* See *Appendix B for more information about the wells.*

2.3.1 REGIONAL PETROLEUM SYSTEM OVERVIEW

Cooper and others (2001) described and illustrated a successful petroleum play within the western part of the Humber Zone in western Newfoundland. In developing their model they showed a petroleum system consisting of two fairways (*see* Figure 18):

a. Within the extensional fairway, reservoirs are in carbonate layers of the shallow-water Lower Paleozoic Carbonate Shelf (*see* Figure 8). The source rock and seal rock layers are in sequences that have been deposited upon, or thrust over, the ancient continental margin. Most of this extensional fairway lies in the Gulf of St. Lawrence west of the island.

b. The inversion fairway lies east of the extensional fairway. Here, deep-water rocks of the Humber Arm Allochthon are significantly deformed by folding and faulting. The rock sequence is further complicated by the fact that some parts of the allochthon were being uplifted by deformation, eroded, and redeposited while the layers of sediment accumulated. Source, reservoir, and seal rock layers are arranged in much more complicated ways because of the deformation events.

The majority of hydrocarbon seeps and shows in western Newfoundland are found in the allochthon in the inversion fairway. Conventional hydrocarbon targets identified and tested to date lie in the faulted structures of the Lower Paleozoic Carbonate Shelf. However, the hydrocarbon potential of western Newfoundland's complex geological setting has never been fully evaluated (Hamblin, 2006). In regards to thermal maturity, large tracts of the Cambro-Ordovician sedimentary rocks of the Humber Zone reside within the "oil window" (*see* section 2.1.3). Exceptions to this occur, such as in the immediate vicinity of the Humber Arm Allochthon's ophiolite complex and in the northernmost areas of the Great Northern Peninsula (Fowler and others, 1995).

2.3.2 RESERVOIR CHARACTERISTICS

This section reviews available data to describe what is known about the qualities of hydrocarbon resources of western Newfoundland. After providing background information about the state of knowledge, it describes a variety of hydrocarbon analyses and well log data.

2.3.2.1 Evaluation of Available Source Rock Data

Despite a long-standing awareness of hydrocarbon seeps and shows (Figures 1 and 6), no systematic documentation or geochemical analyses were conducted on surface exposures of hydrocarbon occurrences by government, academia, or industry in western Newfoundland until the mid-1980s. Evaluation of the unconventional shale plays of the Humber Arm Allochthon has been overlooked until recently. Exploration wells in western Newfoundland have generally targeted conventional reservoirs of the carbonate platform. For example, the three wells drilled at Shoal Point targeted deeply buried carbonate platform plays beneath the Humber Arm Allochthon and in the inversion fairway.

Some limited hydrocarbon studies of both the carbonate platform and the Humber Arm Allochthon have been undertaken by Botsford (1988), Fowler and others (1995), Macauley (1987),

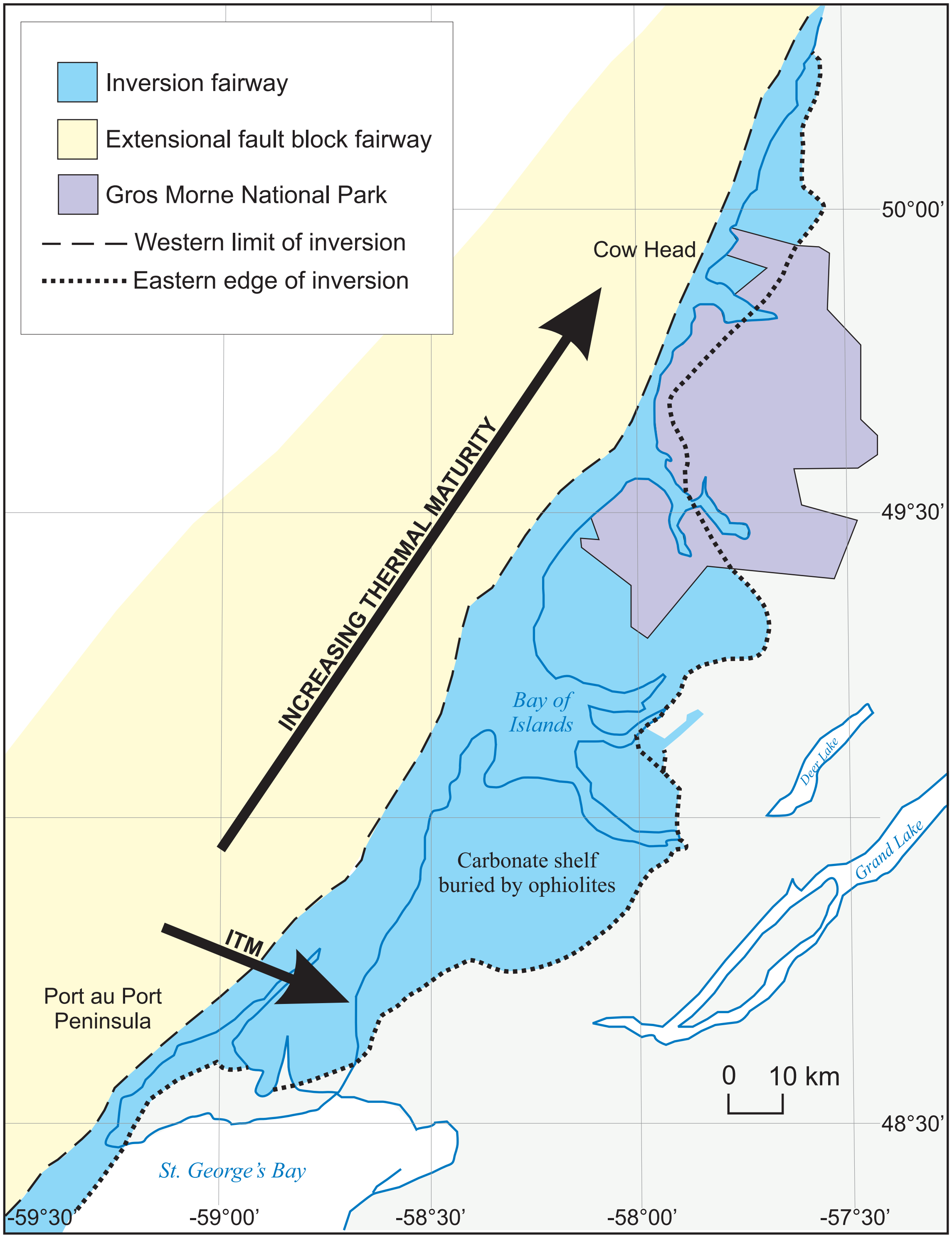


Figure 18. *Structural trap fairways in the Humber Zone of western Newfoundland. In the extensional fairway, rift- and block faulting was caused by crustal extension, affecting rocks of the Lower Paleozoic continental shelf and creating the conditions for large reservoirs to form. In the inversion fairway, reversed (inverted) movement on older faults was caused by later crustal compression, affecting rock layers including the Humber Arm Allochthon and creating the potential for hydrocarbon traps and seals.* ***ITM****, trends of increasing thermal maturity. Figure adapted from Cooper and others (2001); thermal maturity trends from Fowler and others (1995).*

Nowlan and Barnes (1987), Sinclair (1990), Stouge (1986), Weaver (1988), Weaver and Macko (1988), Williams and Burden (1992), and Williams and others (1998). Such studies have allowed a regional assessment of the hydrocarbon and source rock potential in the region. Figures 19 and 20 compile data from three of the studies to provide information about hydrocarbons in samples from different geological settings in the Anticosti Basin. Basic log suites and mud gas records are available for most of the wells drilled in the Port au Port region, but no cores or sidewall cores were taken of the shale, with the exception of the Shoal Point 3K-39 well.

Available data from drillcores and from studies of surface outcrops in western Newfoundland provide a reasonably reliable basis for regional evaluation of the source rocks in western

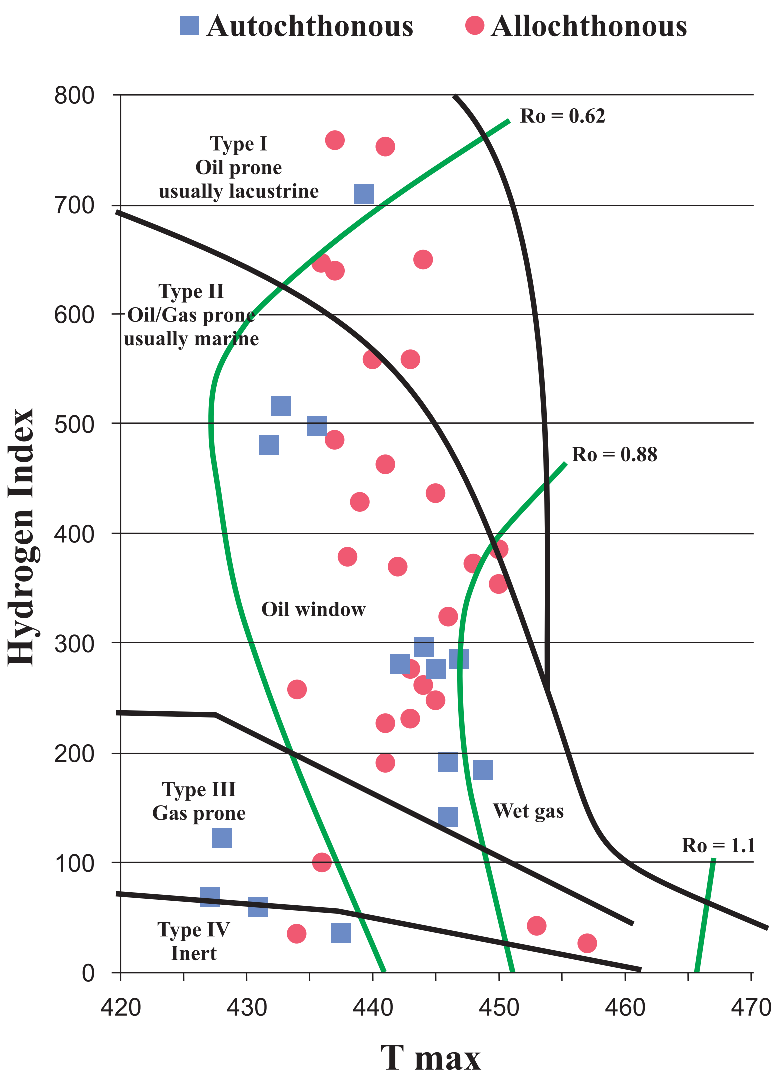


Figure 19. *Thermal maturity plot, Anticosti Basin. Hydrogen index vs Tmax for autochthonous and allochthonous rock samples from the Anticosti Basin in western Newfoundland, superimposed on industry-established fields for kerogen types I, II, III, and IV. The samples have a wide range of thermal maturities, indicating the potential for both oil and gas.* ***Ro****, vitrinite reflectance values, which show thermal maturity increasing from upper left to lower right. Data from Fowler and others (1995), Sinclair (1990), and Weaver (1988).*

Newfoundland. However, with limited drill data and a limited number of well holes, the authors recognize that more data in the future will likely significantly affect interpretations of the Green Point shale play. The discussion of reservoir characteristics focuses on the Port au Port region because this area is a target for exploration of unconventional shale resources.

For this report, historical well logs (as described in company reports) have been examined to evaluate the potential of the Green Point shale as an unconventional reservoir. The CNLOPB's Core Storage and Research Centre (CNLOPB, n.d.) archives the data from wells drilled in offshore regions of Newfoundland and Labrador. The archive includes core, drill cuttings, fluid samples, biostratigraphic slides, and petrographic slides. Fee-based access to view the core is available to the general

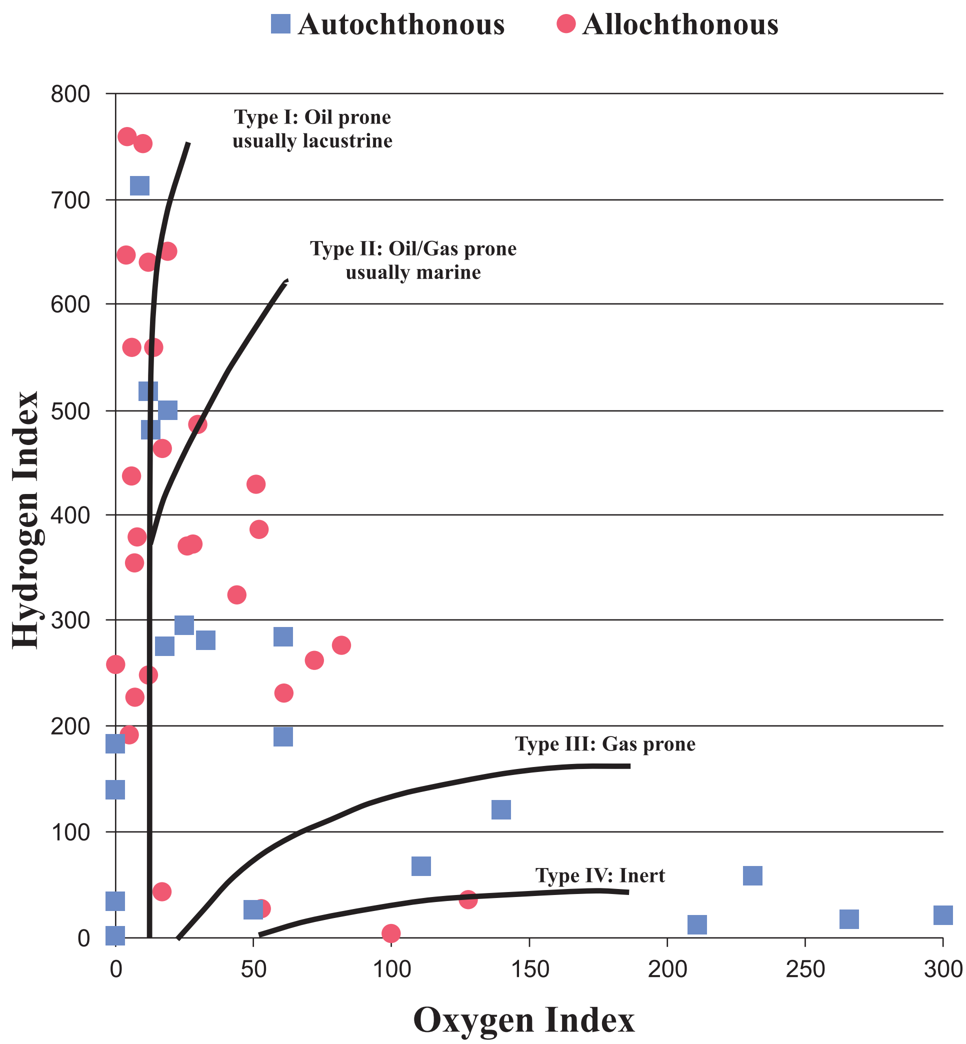


Figure 20. *Hydrogen index vs oxygen index, Anticosti Basin. Kerogen characteristics for authochthonous and allochthonous rock samples from the Anticosti Basin in western Newfoundland, superimposed on industry-established fields for kerogen types I, II, III, and IV (based on a van Krevelen diagram). The samples from western Newfoundland show a wide range of kerogen types, from inert through gas-prone to oil-prone. Thermal maturity of a given kerogen type increases toward the bottom left. Data from Sinclair (1990), Weaver (1988), and Fowler and others (1995).*

public. All of the onshore-to-offshore wells drilled in the Humber Zone are currently off confidential status and final well reports are available from the CNLOPB with the exception of the Shoal Point 3K-39Z well, which has a release date of July, 2014.

2.3.2.2 Hydrocarbon Analyses and Evaluation of Source Rock

In western Newfoundland, Cambrian–Ordovician dolomite of the carbonate platform and some deeper marine sandstones and carbonates are considered potential reservoir rocks (Fowler and others, 1995). Complex patterns of deformation (for example, *see* Figures 9 and 10) can repeat both reservoirs and source rock layers by thrusting and faulting. This can locally juxtapose source and reservoir rocks, potentially creating prospective areas where hydrocarbons could be trapped and accumulate at depth in both onshore and offshore settings.

Fowler and others (1995) noted two trends in thermal maturity in western Newfoundland (Figure 18). One trend shows increasing thermal maturity from south to north between Port au Port and Gros Morne. The other shows increasing thermal maturity from west to east across the Port au Port area, presumably a trend also present regionally both onshore and offshore. *See* section 2.1.3. for background information about thermal maturity and other analytical measurements reported here.

The allochthonous Cow Head Group is host to the most likely source rock in the region (Fowler and others, 1995), since its Green Point Formation contains total organic carbon up to 10.4%. Less likely but possible targets are its deep water equivalents to the east, *i.e.*, the Northern Head Group. The autochthonous Black Cove Formation, part of the Goose Tickle Group, has total organic carbon values higher than 1.4% and may be another regional source rock. Other potential source rocks (based on very limited data) in southern parts of western Newfoundland include autochthonous shale of the Labrador Group and the foreland basin shale of the Table Head and Goose Tickle groups. Farther to the north, all studies of thermal maturation – using microfossils, clay minerals, and metamorphic grade (for example, Botsford, 1988; Nowlan and Barnes, 1987; Stouge, 1986) – indicate that rock units in this area appear to be overmature. This is especially true for samples near the Hare Bay Allochthon.

Shale of the Green Point Formation includes organic-rich (Type I/II) intervals with a hydrogen index up to 759, and Tmax values in the range 434–443. Together these values indicate a thermal maturity below or within the oil window (Bertrand and others, 2003; Fowler and others, 1995; Nowlan and Barnes, 1987; Weaver and Macko, 1988). The geochemical characteristics of oil seeps in the region compare closely to those of the Green Point shale in that maturity increases, at least at surface, from west to east and from south to north, progressing from immature to late mature (Fowler and others, 1995). Green Point shale occurring north of Parsons Pond may reside in the gas window. Chemistry of the oils in the region is consistent with their derivation from a pre-Devonian source containing Type I/II of mostly algal organic matter (Fowler and others, 1995). These lines of evidence consistently point to the Green Point shale as the source of hydrocarbons in the region.

Data for twelve samples of Green Point Formation shale are published in the Geological Survey of Canada's Rock Eval database (*see* section 2.1.3 for information about Rock Eval). The samples' key characteristics are summarized in Table 4.

Table 4. Geological Survey of Canada Rock Eval data for the Green Point shale

Measure	TOC	Tmax	S1 peak	S2 peak	S3 peak	HI	OI
Max. value	7.37	444	1.73	62.06	0.53	753	7
Ave. value	5.86	440	1.32	34.83	0.29	613	5

Note: TOC - total organic carbon; HI - hydrogen index; OI - oxygen index. From Hamblin (2006).

Additional information about thermal maturity has been reported by Williams and others (1998), who analyzed samples of the Cow Head, Table Head, and Goose Tickle groups between Bonne Bay and Table Point. They used indices based on temperature-dependent changes in colour or reflectance of fossils, as summarized in Table 5. Their study supports the Tmax data in Table 4 and places most of these units in the oil window (Figures 19 and 20).

Table 5. Fossil-based indices of thermal maturity for western Newfoundland

Measure	Conodont Alteration Index	Acritarch Alteration Index	Graptolite Reflectance
Min. value	1.5	1.3	0.51
Max. value	5.0	4.0	1.9

Note: From Williams and others (1998).

All the data presented here suggest that the Green Point shale includes thick, thermally immature to mature (and locally overmature) sequences of excellent source rocks. Hamblin (2006) concluded that the data indicate good potential for a hydrocarbon play, provided the region's structural complications can be addressed. Determining the usefulness of the Green Point shale as a hydrocarbon resource will require further study of its rock layers and how they formed, its mineral and chemical composition, the thermal maturity of its hydrocarbons, and the structures affecting its distribution and mechanical properties. It will also be valuable to identify areas where hydrocarbon recovery may be enhanced by pressure variations during development, allowing the capture of natural gas liquids. Often in unconventional reservoirs, the recovery of an associated liquid (*i.e.,* wet gas) as opposed to dry gas improves the economics of a project.

The single sample attributable to the Curling Group and analyzed by Fowler and others (1995) yielded a total organic carbon content of 1.2%. Based on geological similarities, Hamblin (2006) speculated that the Curling Group could be at least as organic-rich as the Green Point shale, although probably more mature. Nevertheless, he concluded they would be very difficult exploration targets: widespread, pervasive faulting and fracturing mean there are no continuous or flat-lying occurrences.

2.3.2.3 Well Log Data

Very few well log data exist for assessing the basic reservoir characteristics of the Green Point shale, either regionally or within the Port au Port Peninsula area. *See* section 2.1.3 for background information about well logs.

For other rock formations beneath the peninsula, published logs provide an excellent illustration of how multiple electric wireline logs and geological logs can be combined to correlate rock layers among a series of wells. Figure 21 shows such correlations in the Lower Paleozoic carbonate shelf sequence (*see* Figure 6 for the locations of the wells). Although these five wells cut through the Green Point shale on their way to the shelf rocks (for example, *see* Figures 9a and 10), electric logs were not taken for those portions of the well except for a gamma ray log in the Shoal Point K-39 well (Stockmal and others, 2004). A gamma ray log of the Shoal Point 3K-39 well also includes the Green Point shale. A photograph of core material from the Green Point shale in well 3K-39 is shown in Figure 22a, and a geological log of the Shoal Point 2K-39 well is illustrated in Figure 23.

For the Green Point shale itself, well logs from Shoal Point 3K-39 provide a variety of findings on topics such as porosity and pressure, rock sequence, deformation, and salinity. That data is publicly available from the CNLOPB and includes the results of injection tests and a drillstem test from Shoal Point 3K-39.

Porosity and pressure. For all the available well log data, measurements on the samples indicate that porosity likely averages 9%, and may range up to 20% locally. Water saturation ranges around 61–87%; however, variations in rock type need to be taken into account. The Green Point shale appears to be normally pressured to slightly overpressured (0.5 pounds per square inch per foot, where the norm is 0.43–0.47). This pressure is typical of many conventional hydrocarbon reservoirs throughout the world.

Rock sequence. Exploration in the 1990s resulted in the drilling of several deep exploration wells through the Green Point Formation (*see* Cooper and others, 2001). Figure 23 shows well lithology logs for the Shoal Point 2K-39 well. It illustrates the lithological variations within the Green Point shale and also the numerous hydrocarbon shows.

The Shoal Point K-39 well drilled first through the Humber Arm Allochthon, then deviated beneath Port au Port Bay to reach a deep conventional play. For that reason, intermediate casing was set in the well at 2175 metres measured depth (1870 metres true vertical depth). No open-hole logs were taken above that point (Stockmal and others, 2004). However, behind-casing gamma ray logs indicate a marked drop in signal at 943 metres true vertical depth, which was interpreted as the base of the shale-dominated Humber Arm Allochthon or possibly the base of the Goose Tickle Group (Stockmal and others, 2004). Below this depth, the gamma ray signal is consistent with the rock types found in the carbonate platform, like those seen in Figure 21.

Deformation. The final report for the K-39 well recognized that rocks of the Humber Arm Allochthon are part of a structurally disturbed, transported sequence that can be expected to contain highly contorted, folded, fractured, and faulted units. The report notes the frequent presence of

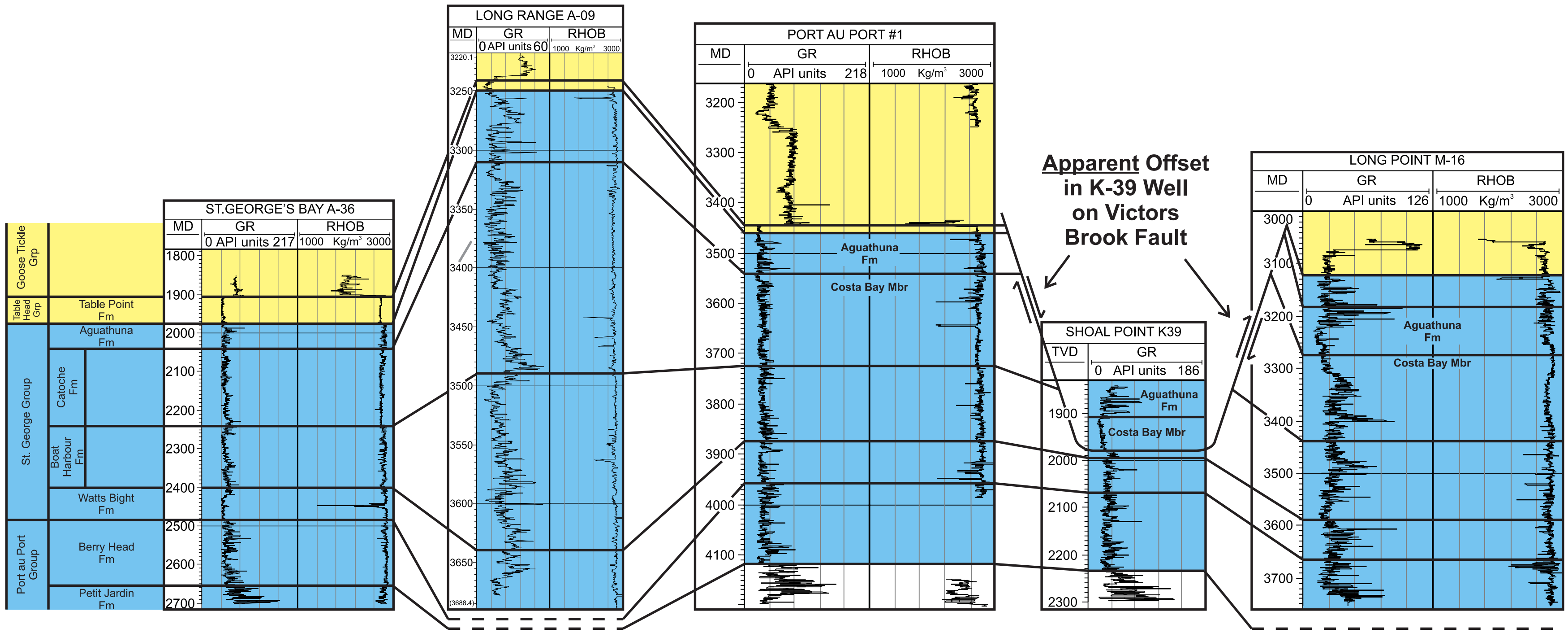


Figure 21. *Stratigraphic correlations based on well logs, Port au Port Peninsula. Rock formations of the Lower Paleozoic shelf sequence in the Port au Port Peninsula include recognizable regional-scale features, allowing correlations among well logs of the St. George's Bay A-36, Long Range A-09, Port-au-Port # 1, Shoal Point K-39, and Long Point M-16 wells. There was no density log for Shoal Point K-39.* ***MD****, measured depth;* ***TVD****, true vertical depth (Shoal Point K-39 well only);* ***GR****, gamma ray log (indicative of radioactivity);* ***RHOB****, bulk density log (a measure of porosity). Adapted from Stockmal and others (2004).*

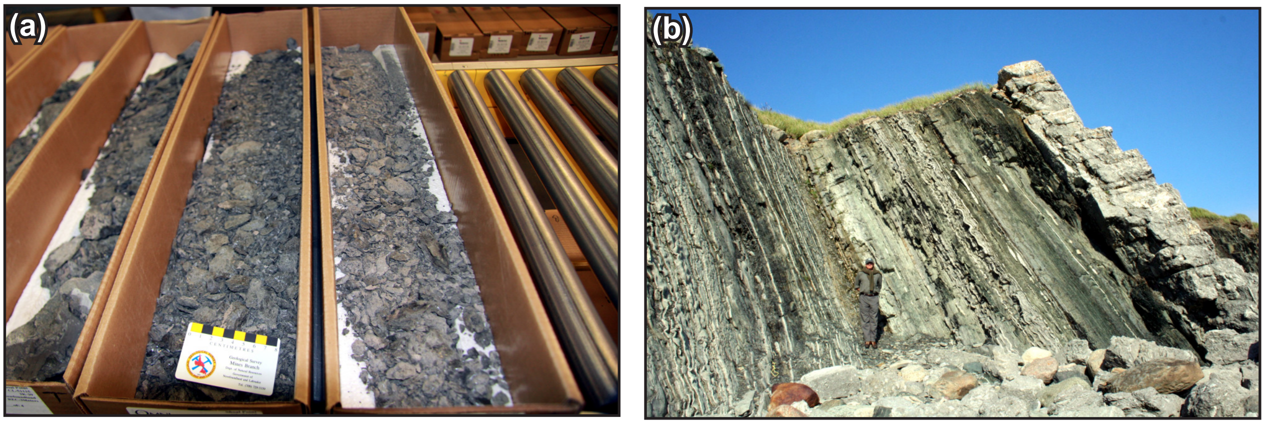


Figure 22. *The Green Point shale: samples and outcrop. a) Black shale of the Green Point shale from a length of core in the Shoal Point 3K-39 well; b) The Green Point Formation at Green Point, Gros Morne National Park. The steeply dipping layers have been tilted past vertical, so the top of each layer is on the left.*

slickensides in rock cuttings of Green Point shale in wells K-39 and 2K-39, particularly in the upper, cased portion of the hole. This, in addition to wellbore instability reported for 2K-39, suggests an abundance of faulting, with deformation being distributed through the weak shale units. The implication is that shale rocks cut by the borehole are structurally disturbed like their surface counterparts of the Humber Arm Allochthon. The highly contorted, folded, fractured, and faulted nature of the sequence can also be seen in the cores from the Golden Eagle Refinery wells drilled at Shoal Point in the 1960s.

The report for the K-39 well also noted lower drilling rates near the base of the allochthon, which may be related to faulting and fracturing. The predominant evidence that the Green Point shale is deformed, fractured, and faulted at depth – as predicted from surface exposure – suggests that an exploration plan to drill and develop possible future unconventional wells in this area will need to carefully assess and address this characteristic. The planning and design of any stimulation program must assess the deformation and design a treatment program that ensures hydrocarbon flow remains within the target formation

Briny water. Briny water was encountered in the Shoal Point K-39 well in rocks of the Humber Arm Allochthon. Water analysis of brine encountered at a true vertical depth of 869–875 metres in the Shoal Point K-39 well indicated 25.8% total dissolved solids composed largely of salt (sodium chloride). This is a substantially greater salinity than ocean water, which typically has similar dissolved solids of 3.5%. The brine zone indicates that the water in the shale has been isolated from other water sources for a prolonged period of time and suggests that the system is possibly sealed at depth. This could illustrate that the system is probably not openly communicating with sea water; however, further study is required to validate this.

Injection tests. The strength and integrity of a formation can be determined using a Leak Off Test or a Formation Integrity Test, both conducted by injecting fluids into the well. Injection tests are used to check well quality, measure the strength of the target rock layers, and gather other in-

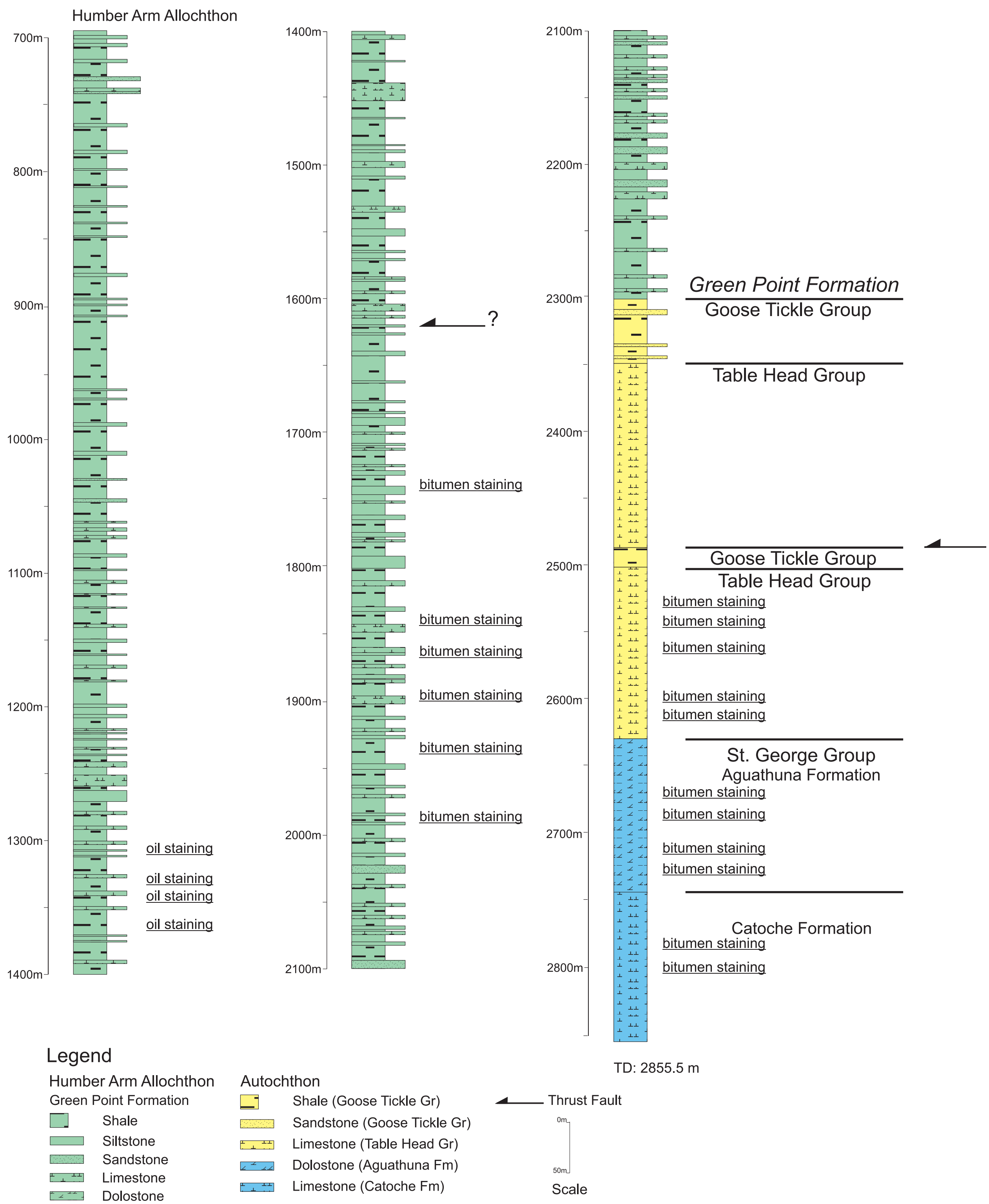


Figure 23. *Log of rock types in the Shoal Point 2K-39 well. The Green Point shale is shown in green and includes thin layers of coarser sediments and carbonates. Rock layers of the carbonate platform and early foreland basin are shown in yellow and blue. Note that a thrust fault has created a repetition (Table Head–Goose Tickle at about 2500 metres, followed by Table Head–Goose Tickle again at about 2350 metres); there may be such a repetition in the Green Point shale as well.* ***TD****, total depth.*

formation used to design well operations. Data from the Shoal Point 3K-39 well injection tests are available from the CNLOPB.

Drillstem test. A drillstem test is conducted during the drilling of a well. It provides valuable information about the fluids in specific rock layers as well as rock permeability and flow potential.

In 1999, a drillstem test was completed in the Shoal Point K-39 well at a measured depth of 1251.5 metres. The final well report includes the drillstem test results, which included recovery of a 375-metre column of briny water (with 258 000 parts per million of sodium chloride) and a 2–metre column of sand in the drillpipe before sand plugged the tool. The drillstem test showed good initial reservoir pressure (in the range of about 10 000 kilopascals), which built back up reasonably well. The initial flow test recovered 14 600 cubic metres per day of dry gas. This decreased to 150 cubic metres per day after the third flow test and subsequent accumulation of salty water in the drillpipe.

3. STIMULATION TECHNIQUES

For unconventional hydrocarbon reservoirs such as shale plays, the permeability of the shale needs to be enhanced using techniques called "stimulation" in order to get the oil or gas to flow to the surface for collection. This section reviews some basic background information about stimulation techniques, including drilling procedures and well construction techniques (3.1) and a description of hydraulic fracturing (3.2). It also explains the three stages in developing an unconventional reservoir (3.3) and includes a discussion of specific stimulation techniques and other considerations (3.4). Because hydraulic fracturing and related operations require significant amounts of water and produce significant volumes of waste water, there is also a brief review of provincial water-related regulations and baseline data (3.5).

3.1 WELL DRILLING

Thanks to advances in drilling technology, wells can be drilled in a variety of orientations. They can reach targets that may be far below and also a significant lateral distance away from the wellhead, like the onshore-to-offshore wells in western Newfoundland (*see* Figure 17 for locations). The base for drilling operations is a well site or well pad hosting one or more wells.

3.1.1 HORIZONTAL DRILLING

In the past, an oil or gas well was usually designed to be drilled vertically downward until the hydrocarbon-bearing layer was reached. The ability to exploit unconventional shale oil or shale gas depends on techniques that allow wells to be drilled vertically and then sideways. This is called deviated or horizontal drilling (*see* Figure 2 and Figure 24). Horizontal drilling, like conventional drilling, employs cemented and metal well casings to protect groundwater.

For horizontal drilling, the wellbore is drilled vertically to a precisely planned depth and then angled through a sharp bend so that the rest of the well follows along, and stays within, the target formation. This is done because vertical drilling would pass straight through rock layers, accessing only a small volume of the target formation. Wells that follow along the layering, by contrast, are exposed to a far greater volume of the hydrocarbon-bearing rock. Effectively fracturing a shale formation in a horizontal well means the volume of shale that can release its hydrocarbons is increased significantly.

Horizontal drilling also enables an array of wells to be drilled in different compass directions from a single well site. Consequently there is substantially less impact on the environment to develop an area than if vertical wells alone were used. This, by virtue of the fewer well sites, not only decreases the environmental and land-use footprint of the industry but also lowers the overall cost of development, decreases the impact on wildlife and on the amount of dust, noise, and traffic over the life of a development.

3.1.2 INTEGRITY OF THE WELL CASING

Wells are drilled using a drill string. As each hole section is completed, the drill string is replaced with a series of steel pipes collectively known as a casing string. These casings are cemented (Figure

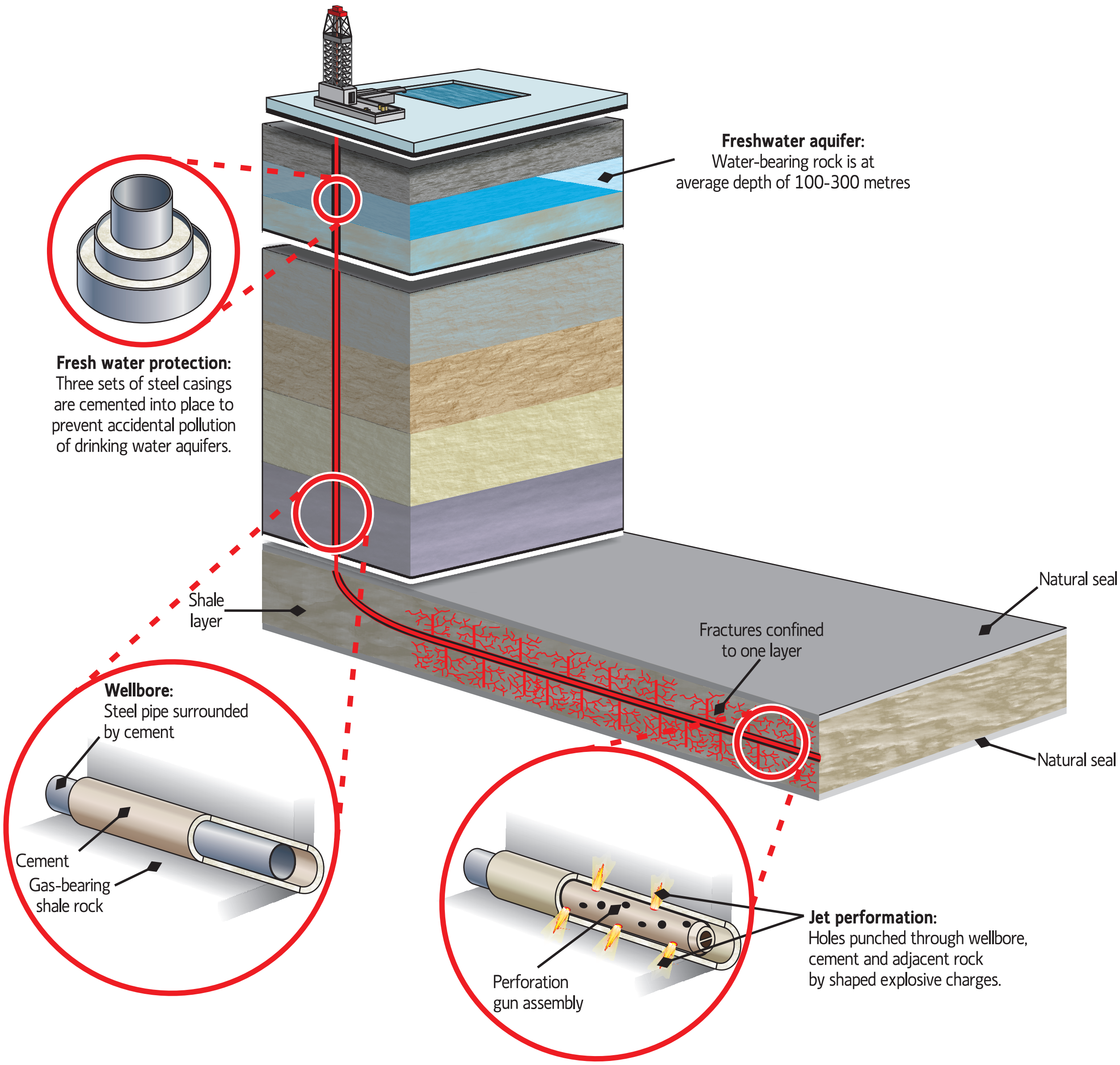


Figure 24. *Schematic diagram of a hydraulic fracturing operation. Horizontal drilling technology allows fluid access from the well to the target formation but uses cemented casings to prevent leakage elsewhere along the wellbore. Modified from similar image on the Canadian Association of Petroleum Producers (CAPP) website, www.capp.ca.*

24) to isolate a well from its host rock. Cemented steel casing strings are a key part of a well design and are essential to ensure the integrity of a well. Cemented casing strings protect against the unintended migration of hydrocarbons, injected fluid, or waste water into and out of a well. They protect important water resources by isolating them from the oil, gas, and waste water inside of the well.

The casing used in Newfoundland and Labrador is required to meet the Government of Newfoundland and Labrador regulations with regard to the design of the casing – for example, calculation of likely burst pressure, collapse loading, and tensile loading design including safety factors. Other requirements addressed by the regulations include alternative casing design, casing setting depths, and casing installation programs. Regulations cover the proper cementation of casing as well. The cement mixture and process, cementing intervals for casing and liner, and the required waiting time for cement to develop sufficient compressive strength are all specified. Legislation, regulations, guidelines, and standards under the jurisdiction of the CNLOPB may also apply.

In addition, voluntary best practices and guidelines are used by the industry to ensure that wells drilled in Newfoundland and Labrador retain all operational fluids and pressures within the wellbore. The industry guidelines and best practices address how best to protect groundwater aquifers by preventing the migration of fluids from the wellbore into overlying porous formations. They also reduce the risk of inter-wellbore communication with nearby wells – particularly in the case of a hydraulically fractured well – and how best to manage well pressures in the event of inter-wellbore communication to prevent surface water impacts. Essentially the goal is to ensure that the well construction and wellbore integrity is sufficient to withstand the anticipated pressures involved in drilling the well or preparing for its operation.

Implementation of wellbore best practices has implications for some of the old wells drilled during the early exploration history (*see* section 2.2.1), including those at Shoal Point, Parsons Pond and St. Paul's Inlet. Best practice initiatives would involve historic wells being mapped, effectively sealed below ground level, and capped before any advanced hydrocarbon development is approved in close proximity to a historic well.

The Government of Newfoundland and Labrador requires companies drilling wells to pay a deposit that is set aside for reclamation or abandonment. The deposit is also used to insure that companies comply with the regulations. At the federal level the Government of Canada is exploring changes to the legislation that would follow a "polluter-pays" principal in which the party responsible for producing pollution is also responsible for paying for any damage done to the natural environment. This type of legislation provides an incentive to follow best practices and ensures that in the event of an accident there is a means to fund a thorough reclamation of the environment.

3.2 HYDRAULIC FRACTURING AND SUBSEQUENT OPERATIONS

Hydraulic fracturing, or "fracking" (sometimes spelled "fracing"), is a method used by petroleum engineers to stimulate, or improve, fluid flow from rocks below ground. The technique involves injecting, *i.e.*, pumping, a fluid (often water-based) into a prepared borehole until the fluid pressure at depth causes the rock to fracture at a specific target depth. A schematic diagram showing the general features of a hydraulic fracturing operation is shown in Figure 24. The pumped fluid contains small particles known as proppant (often quartz sand or ceramic sand) that serve to prop open the fractures. The fluid also contains small amounts (typically less than 0.5% in total by volume) of chemical additives to help initiate fractures, protect the borehole lining, and optimize the fluid viscosity (Figure 25 and Table 6).

After fracturing, the pressure in the well is lowered, creating a pressure gradient so that hydrocarbons flow out of the shale and into the well. The fluid, now containing released hydrocarbons, may combine with saline water containing dissolved minerals from the shale formation ("formation water"). This mixture of returned fracturing fluid and formation water is collectively called "flow-

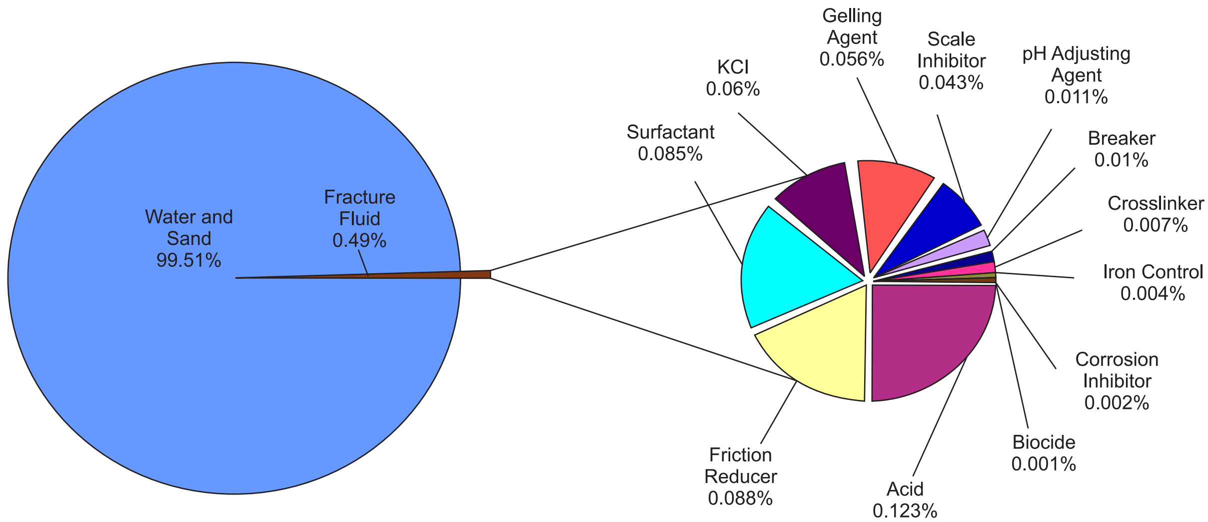


Figure 25. *Chemical make-up of fracture fluid. Fracture fluid is mostly water and sand, as shown on the left. The proportions and uses of a dozen common fluid additives appear on the right. Modified from Arthur and others (2008, p. 13, Exhibit 8).*

back water". Typically, flowback water is diverted to isolated storage tanks until the volume of fluid initially injected is recovered. Water continues to flow to the surface over the lifetime of an operation as the well continues to produce oil or gas. This is called "produced water". Both flowback water and produced water are generally considered waste waters (U.S. Environmental Protection Agency, 2013a).

The permeability of the rock layer that contains oil or gas dictates whether the reservoir needs to be hydraulically fractured. When permeability is high enough – about 50 microdarcys for most oil zones, or 1–5 microdarcys for gas zones – fracturing is not necessary to establish an economic production rate (King, 2012). This is considered a conventional reservoir. At lower permeability, or where oil viscosity is high or reservoir pressure is low, the flow of fluids toward the wellbore needs to be enhanced by stimulation techniques such as hydraulic fracturing. In the case of shale that has very low permeability, hydrocarbons may not flow at economic rates without extensive hydraulic fracturing.

Some of the possible risks associated with hydraulic fracturing of shale are discussed in section 4.

3.3 STAGES OF DEVELOPMENT OF UNCONVENTIONAL RESERVOIRS

Extraction of hydrocarbons from tight reservoirs typically consists of three stages (Royal Society and Royal Academy of Engineering, 2012):

a. **Exploration and development**. A small number of vertical wells (perhaps only two or three) are drilled and fractured to determine if the hydrocarbons are present and can be extracted. This exploration stage may include an appraisal phase where more wells are drilled and fractured to understand the fracturing characteristics of the shale – for example, how

Table 6. Elements of a typical fracture fluid

Product	Main Ingredient	Purpose	Also Commonly Found or Used In
Water	H_2O	Expands the fracture, delivers sand	Landscaping and manufacturing
Proppant (sand)	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Diluted acid	Hydrochloric acid (*i.e.*, muriatic acid)	Helps dissolve minerals, initiate cracks in the rock	Swimming pool chemical, cleaner
Biocide	Glutaraldehyde	Eliminates bacteria, which can produce corrosive by products	Disinfectant, sterilizer for medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed break-down of the gel	Hair colouring, disinfectant, manufacture of common plastics
Clay stabilizer	Potassium chloride	Prevents clays from swelling or shifting	Low-sodium table salt substitute, medicines, IV fluids
Corrosion inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	Pharmaceuticals, acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, cosmetics
Friction reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner
Friction reducer	Petroleum distillate	"Slicks" the water to minimize friction	Cosmetics including hair, make-up, nail, skin products
Gelling agent	Guar gum or hydro-xyethyl cellulose	Thickens the water in order to suspend the sand	Thickener in cosmetics, baked goods, ice cream, toothpaste, sauces, salad dressings
Iron control	Citric acid	Prevents the precipitation of metal oxides	Food additive, beverages; lemon juice is ~7% citric acid
pH adjusting agent	Sodium carbonate or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Laundry detergents, soap, water softener, dishwasher detergents, glass, ceramics
Scale inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Automotive antifreeze, household cleansers, de-icer, paints, caulking
Surfactant	Isopropanol	Increases the viscosity of the fracture fluid	Glass cleaner, multi-surface cleansers, antiperspirant, hair colour

Note: The compounds shown are representative of the major compounds used in hydraulic fracturing of gas shales. However, the specific compounds used will vary depending on company preference, source water quality, and the specific characteristics of the shale. Modified from U.S. Department of Energy (2009) and from Arthur and others (2008, p. 13–14, Exhibit 9).

old fractures behave and how new fractures will tend to propagate – and to establish whether the shale could produce petroleum economically. Further wells may be drilled to ascertain the long-term economic viability of the shale. All petroleum exploration in western Newfoundland is currently at this phase of development.

b. **Production**. The production stage involves the commercial production of hydraulically fractured hydrocarbon-bearing shale. Shale with commercial reserves of petroleum can typically be greater than a hundred metres thick and can extend over hundreds of square kilometres. The shale formations will normally dip at a shallow, nearly horizontal angle. At this stage, vertical drilling alone is not suitable, since a vertical well would tend to pass straight through the layers and access only a small volume of the shale. During production, arrays of fracture-enhanced horizontal wells drilled from single or multiple well sites result in economic production of large volumes of previously inaccessible hydrocarbons.

c. **Abandonment**. Like conventional wells, a well in a shale play is abandoned once it reaches the end of its producing life and extraction is no longer economically viable. Sections of the well are filled with cement to prevent inter-well communication, such as hydrocarbons flowing into water-bearing zones or up to the surface. The well casings are cut off below the surface, a cap is welded into place, and the site restored to its original contour.

The exploration and development phase provides valuable information about the target shale play. The types of data that can be collected at this stage are listed in Table 7. These include properties of the rock itself and of the hydrocarbon it contains. All of these data are used to create a detailed understanding of the shale play and of the sedimentary basin, in order to determine if the hydrocarbon resources can be extracted safely and commercially.

Table 7. Properties assessed in a hydrocarbon play

Property	**Methods and Measurements**
Shale characteristics	Coring (for porosity, permeability, density)
Gas-in-place	Core analysis: canister desorption and adsorption isotherms; GeoJar (for reservoir potential)
Gas geochemistry	Stable isotopes, gas composition (for gas origin, impurities)
Organic matter	Rock Eval: total organic carbon, kerogen type, etc.; biomarkers, thermal maturity (for reservoir potential)
Rock mechanics	Compressive strength, elastic moduli, Poisson's ratio (for drilling and fracturing properties)
Shale mineralogy	X-ray diffraction, thin sections, shale gas log, capillary suction test (for sensitivity to fracturing fluid)
Basin geology	Geological mapping, geophysical surveys (for regional-scale sedimentology model)

3.4 FRACTURE STIMULATION TECHNIQUES

Hydraulic fractures are produced by injecting fluid into a rock formation or reservoir at pressures that exceed the fracture pressure of the rock, *i.e.*, the pressure at which the rock breaks (Nolen-Hoeksema, 2013). Two injection methods have been used: sand-gel fracture treatment, and slickwater fracture (or low-sand) treatment. Sand-gel can have advantages because the gel, being more viscous than plain water, carries proppant (sand) effectively. However, use of the slickwater fracture treatment has become more common over time than the sand-gel treatment, partly because the slickwater fracture treatments are more economical, at half to one-third the cost of the sand-gel. Sand-gel can also cause technical problems; when using larger volumes in certain shale plays, the gel residue makes the fractures less permeable.

3.4.1 SLICKWATER FRACTURING TREATMENT

Slickwater fracturing treatment uses a friction-reducing chemical additive that allows the fracturing fluid to be pumped into the formation at a high rate. The treatment involves pumping large volumes of lightly treated fresh water (about 3.8 million litres), with a low sand concentration (45 000 kilograms) at rates of about 60 barrels per minute (*see* section 4.5 for further discussion of water requirements).

Slickwater fracturing has been used in the Barnett shale of Texas since the mid-1990s, when it replaced the less reliable sand-gel treatments. Although not dramatically increasing well performance, slickwater treatment effectively extends the length of the hydraulic fractures at one half to one third the cost of conventional stimulation (Bruner and Smosma, 2011). It has been applied successfully in basins all over North America. A routine completion practice is to re-stimulate wells after several years of production (Pollastro, 2007). Wells previously stimulated by other techniques can be re-stimulated by slickwater treatment, connecting additional reservoir rock to the borehole and sometimes exceeding the original initial production (Bowker, 2003; Jarvie and others, 2007).

Slickwater fracturing can aid in clearing the well of water once production begins. Creating a network of good quality fractures leading into the borehole, which is the aim of the treatment, also facilitates the flowback of the fracture fluid. From 20–30% to 60–70% of the injected volume is usually returned over several days (Bruner and Smosma, 2011; Givens and Zhao, 2009). The gas released from the rock also helps lift the fracture fluid to the surface.

Effective flowback is important because water that remains trapped in a reservoir can impede hydrocarbon production and require swabbing or pumping, adding cost to the operation. With any fracturing treatment, the problem of water production regularly occurs throughout the life of many wells due to the flow of formation water from the rock layers. For example, wells in the Barnett shale are known to produce a lot of water – on average, 450 barrels (72 000 litres) per day for the life of a well (Sumi, 2008). *See* section 4.7 for a further discussion of water management.

3.4.2 FRACTURE BARRIERS AND CONTAINMENT OF HYDRAULIC FRACTURE SYSTEMS

It is important that hydraulic fractures are confined to the "tight" rock of the reservoir and do not grow into, or connect with, other rock formations above and below. The fracturing is strictly planned to prevent water invading from the nearby formations, which could impede production. The height of the hydraulically induced fractures is also controlled so that the effects of the stimulation energy is not conducted away from the shale.

A major factor in assessing shale plays is the presence or absence of rock layers that act as barriers, which are necessary for a large fracture treatment. The standard suite of well logs (Table 3, Well Log Measurements) is used to identify the rock type (sandstone, shale, or carbonate) above and below the shale. Measurements from a dipole sonic log are then used to calculate the mechanical properties of different rock layers including the pressures at which the surrounding rock formations would fracture. In this way, a well engineer can predict what will happen when the artificially created fractures penetrate the rock layers above and below the shale (Bruner and Smosma, 2011).

Underlying and overlying formations may contain natural features (such as fractures, faults, and voids of various sizes, including caverns) that vary from the characteristics of the reservoir rock. These features are known as "inhomogeneities", and their presence indicates that a formation has strong and weak areas. Such features can reduce the effectiveness of hydraulic fracturing in a shale (Jarvie and others, 2007). Standard well logs cannot always discover these features. However, electric image logs can aid in locating troublesome water-bearing features (*see* Table 3) as well as measure hydrocarbon saturation, the tilt of the rock formation, and the occurrence of natural fractures. A 3-D-seismic analysis using seismic survey data (*see* section 1.5.1) can also locate faults that might serve as a water conduit. The operator of the well is usually able to cement the well casing to close off access to a fault, thereby reducing the risk of perforating near a fault (Givens and Zhao, 2009).

3.4.3 NATURAL FRACTURES AND FAULTS

Wireline logs (*see* Table 3) – if calibrated with data from drillcore or cuttings and accurate mud-resistivity measurements – can indicate the presence of open fractures in a formation as well as their orientation and length. Open natural fractures are known to inhibit the growth of hydraulically induced fractures, but less is known about what happens to mineralized or healed fractures. Jarvie and others (2007) found that healed fractures, usually located near major fault planes, are less responsive to hydraulic fracturing than open fractures because they cannot connect sufficient shale surface area to the wellbore.

Bowker (2007) claimed that healed fractures enhance the effectiveness of a fracture treatment by serving as zones of weakness in the shale. For instance, because the contact between shale wall-rock and calcite-filled fractures pulls apart easily compared to solid shale, mineralized fractures will open during stimulation. However, in the Barnett shale, wells drilled on a fault or structural high (where faults tend to occur) have a higher fracture gradient, requiring greater force to induce fractures. In this situation, fractures tend to propagate toward or down the fault plane (Givens and Zhao, 2009), lowering the efficiency of fracture treatment.

“Slickensides” form where friction heats a rock surface during movement along a fault; the slickensides are usually characterized by an aligned, often fibrous, mineral coating or a polished striated surface. The risk that slickensided zones would provide a conduit for communication between fracture fluids and shallower potable water zones is thought to be very low due to the small scale and localized nature of this feature as well as the vertical distance between the potential fracture zones and the potential shallower potable water zones (King, 2012; also *see* section 4.6). However, where slickensides accompany other signs of severe or complex deformation, a thorough evaluation of the risks to a successful operation would be warranted given that available research has not proven conclusive.

3.4.4 HYDRAULIC FRACTURING AND THE GREEN POINT SHALE

The hydraulic-fracturing techniques described in sections 3.4.1 to 3.4.3 relate directly to some characteristics of the Green Point shale. Summarized in this section are a number of observations based on drill results and rock evaluations that are useful when considering the possible future hydraulic fracturing of the Green Point shale. Its typical mineral composition, based on available data, is listed in Table 8.

Mineral composition. In the Green Point shale the primary clay is illite, which is also the main clay in the Barnett shale of Texas. Some types of clay swell or break loose in response to water, but illite does not. This makes the application of slickwater fracturing feasible in western Newfoundland. Zones with a higher proportion of silicates are more brittle and hence fracture more readily.

Table 8. Typical mineral composition of the Green Point shale

Mineral	% of Total
Quartz	35–50%
Clays, primarily illite	10–50%
Calcite, dolomite, siderite	0-30%
Feldspars	7%
Pyrite	5%
Phosphate gypsum	trace
Mica	<5%

Note: Based on data from Shoal Point Energy 3K-39 well.

Natural barriers. A drillstem test for a section of the Green Point shale at a true vertical depth of approximately 1095–1103 metres in Shoal Point K-39 indicated some ability to flow without fracture stimulation. However, only minor quantities of gas (the well was considered dry) with approximately 74 barrels (12 000 litres or 3100 gallons) of very salty water, containing 25–30% total dissolved solids, were recovered before the test tool plugged with sand. The highly salty water recovered from this well test indicates that the zone tested is not in communication with shallower potable water zones or with sea water.

Fractures. Of the several wells that have been drilled and evaluated in the Shoal Point region, none has shown the presence of open fractures. However, it is apparent from thin section and visual analyses of core from the Shoal Point K-39 and 3K-39 wells that there are abundant closed fractures filled mostly by calcite or less often, bitumen. This suggests that the rock was fractured while being distorted by deformation, then during or after deformation (*see* section 3.4.2) the open spaces were filled by mineral cement.

Slickensides. Slickensides on a millimetre scale are abundant in the shale in the Shoal Point K-39 well, suggesting that a full evaluation of their effect on reservoir properties is needed, especially permeability. Depending on the results of such a study, it will be possible to decide whether to avoid or fracture these slickensided zones, especially if they occur on a metre scale as well as the millimetre scale of the cored sections.

Deformation. The Green Point shale is extensively deformed, its rock type varies from one location to another, and it contains abundant small-scale structures such as natural fractures and cleavage. This is different from other hydrocarbon-bearing shales that are currently being exploited in North America. Determining whether the deformation in the Green Point shale would aid or adversely affect the hydraulic-fracturing process is not possible with the current available data. A go slow approach to exploration would be needed to obtain new information on the impact of hydraulically fracturing the formation. A small-scale test is typical in the process of exploring for unconventional resources.

Containment. Preliminary evaluation of the Green Point shale as an unconventional target, in the Shoal Point 3K-39 well, indicated that the potential target layers of shale were at depths of 1000–1720 metres below sea level. Because the target shale in the Shoal Point region is located offshore, the migrating of fracture fluid into a local aquifer would not be a concern. The migration of fluid to the sea floor would be unlikely because the highly salty water recovered from the Shoal Point 3K-39 well test (*see* Natural barriers, this section) implies that the zone tested is not in communication with the sea bed.

3.5 WATER SUPPLY AND QUALITY IN WESTERN NEWFOUNDLAND

Hydraulic fracturing requires significant amounts of water; and the production of unconventional hydrocarbon resources generates waste waters requiring treatment, storage, and/or disposal, all with the potential for environmental impacts. This section reviews the water-related regulatory environment in Newfoundland (3.5.1) and summarizes available baseline data related to the impacts of unconventional hydrocarbon operations on water supply and water quality (3.5.2). For a review of potential water-related risks, *see* sections 4.5, 4.6, and 4.7.

3.5.1 WATER-MANAGEMENT REGULATORY ENVIRONMENT

In Newfoundland and Labrador, the Province's Environmental Protection Act and Water Resources Act place responsibility for managing water resources with the Water Resources Management Division of the Department of Environment and Conservation. That division works to enhance, protect, and conserve existing water resources as well as to develop and control water supplies so that water is effectively utilized.

Because any industrial activity including petroleum operations and hydraulic fracturing may have adverse environmental effects and involve the use of water, ministers of both the Department of Environment and Conservation and the Department of Natural Resources have regulatory responsibilities for industrial impacts on water resources. Oil and gas exploration and development cannot proceed without regulatory approvals or permits. The granting of these approvals includes the authority to prescribe terms and conditions necessary to ensure the protection of the public, the Province's environment, and its water resources.

Surface and groundwater resources that supply drinking water to provincial communities are protected in a variety of ways. Of the 483 public water sources in the province, 301 are from surface water in the form of rivers, ponds, and lakes, and 182 are groundwater sources accessed by drilled or dug wells. In total, 314 or 65% of these were designated as Protected Public Water Supply Areas as of the end of the 2011–2012 fiscal year, meaning 91% of the serviced population of the Province falls under this program (Newfoundland and Labrador Department of Environment and Conservation, 2013a, b). Communities serviced by wells can apply to establish a Wellhead Protected Water Supply Area. This program is designed to protect the recharge area of a public well's aquifer by regulating land-use activities and potential sources of contamination within the recharge area. The primary goal of a public water-supply area is to provide a reliable and affordable supply of clean, safe drinking water. All other activities are secondary and permitted only if there is no threat to drinking water quantity or quality.

A permit is required for any development activity within a protected public water-supply area. When a permit application is received by the Department of Environment and Conservation, the municipal authority responsible for the protected water supply area is contacted. This provides an opportunity for the municipal authority to bring forward any objections or concerns regarding the development activity and also to suggest conditions under which the proposed development may be able to proceed. Each development proposal is assessed on a case-by-case basis considering the location, nature, and duration of the project, and the potential risk to water quality or quantity.

The Department of Environment and Conservation also administers the Province's Environmental Assessment program. Any project such as hydrocarbon operations that could have a significant impact on the natural environment must be presented for examination. The environmental assessment process ensures that development proceeds in an environmentally acceptable manner. When the potential environmental effects of a project are of concern, the environmental assessment process is helpful because it requires comprehensive project planning and design for maximum environmental protection. It enhances coordination among government departments, creates accountability, and promotes an exchange of information about the project. As well, it provides an opportunity for the public to comment or voice concerns about a proposed project. Once the environmental assessment is complete, the process can also facilitate permitting and regulatory approval.

A detailed water-resource management plan would be a key component of any proposed industrial activity such as hydraulic fracturing. The analysis of potential impacts on water resources would be completed as part of the environmental assessment.

3.5.2 AVAILABLE DATA

In western Newfoundland, private water wells are analyzed when they are initially drilled, and these data are housed in a database within the provincial Department of Environment and Conservation. The Department's website includes a valuable source of information on various aspects of available water-resources data (Newfoundland and Labrador Department of Environment and Conservation, 2013a). Most of the water-quality monitoring done by the Provincial Government is for public drinking water supplies, typically located in population centres and not necessarily where industrial activity is planned. There is no routine (for example, annual or biannual), systematic regional analysis of well water, groundwater, and aquifers along the west coast of Newfoundland.

There are numerous naturally occurring hydrocarbon seeps in western Newfoundland, so a water well or groundwater aquifer could become contaminated due to natural processes. Some petroleum occurrences in groundwater have already been documented in the region (AMEC Earth and Environmental, 2008). This potential for pre-development, natural contamination means that the collection of baseline, regional-scale data is recommended before any industrial activity such as hydraulic fracturing occurs. Once baseline data are collected, a continuous monitoring program can evaluate any changes to the water quality and address public concern about adverse effects on local aquifers. Without baseline data, the potential source of any future petroleum contamination – natural or industrial – would be open to question.

Because each hydrocarbon play is different, detailed information about the location, extent, and form of the rock layers needs to be evaluated and defined in relation to local aquifers, and the risks to public water supplies need to be fully evaluated before hydraulic fracturing and subsequent production operations begin (Healy, 2012). The geometry and predictability of the rock layers involved (for example, how the target formation is oriented and how it is deformed, if at all) are extremely important in regions where the tectonic structure and history are complex, as they are in western Newfoundland. Obtaining additional high-quality geological data about the Green Point shale is thus as important to environmental assessment as it is to supporting exploration and development of the resource.

4. POSSIBLE RISKS ASSOCIATED WITH HYDRAULIC FRACTURING

The development of hydrocarbon resources comes with consequences similar to those of other industrial activities such as mining, forestry, and even agricultural industries. There will always be an environmental impact associated with developing the economic potential of natural resources. Understanding risks and managing them diligently allow the benefit to be derived with a minimum negative impact. Currently the state of knowledge about the risks of unconventional hydrocarbon operations is mixed.

On one hand, hydraulic fracturing has been used in the United States since the 1940s. Statistically, the number of proven environmental impacts caused by hydraulic fracturing remains small in relation to the volume of hydraulic fracturing activity (Healy, 2012). One estimate is that approximately one million oil and gas wells have been drilled and hydraulically fractured (King, 2012), including over 200 000 wells in western Canada (Canadian Association of Petroleum Producers, 2012).

On the other hand, in spite of this widespread use, very few peer-reviewed scientific studies have been published examining the risks associated with hydraulic fracturing. Because the risk is not well-quantified, the best approach at this stage is to consider the full range of possible impacts, their magnitude, uncertainty, and potential environmental effects (Healy, 2012).

This section addresses aspects of hydraulic fracturing that are most commonly a subject of public concern (4.1–4.9) and provides an overview of the risks (4.10).

4.1 CHANNELS OF COMMUNICATION

Open channels of communication between operators and affected communities will ideally lead both to the reduction of risks and to a level of community confidence regarding those risks. One aspect of good communication is creating increased awareness and understanding of hydrocarbon development activities. Another is providing opportunities for constructive input into the assessment and development processes, opening up opportunities for effective, two-way communication between industry and community participants.

The development of hydrocarbon plays suitable for hydraulic fracturing operations generally takes place over several years. That makes it especially important for companies and affected communities to build relationships that can endure the lifecycle of a project. The immediate benefits of increased hydrocarbon production can be measured fairly easily (for example, jobs, income levels, and tax revenues), but the potential for other types of impacts is harder to measure. Unwanted socio-economic impacts can include rapid, unplanned industrialization, impact on other land uses and activities such as tourism, the effects of an uneven distribution of costs and benefits among community members, loss of community cohesiveness, and increased stress levels.

Operators and communities should have a comprehensive plan for ongoing engagement about the effects of play development, with open channels of communication among all stakeholders, including the general public, landowners, and local authorities. All those involved can facilitate the engagement process by participating and staying informed about the issues.

4.2 SURFACE INFRASTRUCTURE DEVELOPMENT

How large an area will be affected by surface infrastructure development, and over what period of time, will vary depending on the nature of the target play. Relatively few drill sites may be active at any one time, but the cumulative environmental impact of an entire program of resource development needs to be carefully assessed (Healy, 2012).

Developing a shale hydrocarbon prospect using hydraulic fracturing typically involves repeated drilling over a wide area, often on a grid pattern as one site is drained of its resource. Alternatively, a shale play can be developed using multi-well pads, *i.e.*, horizontal boreholes drilled in different directions and possibly to different depths from the same well, reducing the number of sites needed (*see* section 3.1).

The repeated hydraulic fracturing of a given borehole follows a law of diminishing returns as the rock volume around the base of the well is effectively drained of petroleum. Even so, the time a well is productive varies greatly depending on the geology of the shale formation and the efficiency of the hydraulic-fracturing process. Petroleum hydraulic fracturing operations can span a wide range of time intervals, from several days to many years (Massachusetts Institute of Technology, 2011). A vertical well in the exploration phase would have operations lasting only a few hours. This would be the likely first step in any exploration well in Newfoundland.

4.3 WELL CONSTRUCTION, OPERATION AND INTEGRITY

Well construction of poor quality is the dominant source of pollution problems in the petroleum resource industry. This includes most incidents that have wrongly been blamed on the hydraulic fracturing process itself (King, 2012). Well integrity is achieved by isolating shale gas or oil from the surrounding rock formations, thus preventing it from leaking out of the well (*see* Figure 24).

Poor well integrity can result in a variety of problems. For example, fluids may escape suddenly from porous and permeable formations, reaching the surface in an uncontrolled blowout. If poor cementation is a problem, fluids may escape and move up or down inside the well, perhaps between the casing and the rock walls of the well or perhaps between layers of casing. That type of problem is called an annular leak. If a casing is fractured or other gaps allow fluid to escape and flow out into the surrounding rock layers, a radial leak occurs (Royal Society and Royal Academy of Engineering, 2012).

Rock layers that lie above the target reservoir naturally isolate it from rock layers that host groundwater at shallower depth (*see* Figure 24). It is likely that the two resources have remained isolated for millions of years. The proper construction of an oil well ensures the continued protection of fresh-water-bearing zones even when the well is idle, plugged, or abandoned. Best practices for well construction use multiple barriers including steel casings, cement sheaths, and other mechanical isolation devices to prevent the migration of fluids and provide long-term protection of groundwater.

4.3.1 BLOWOUTS

Although blowouts are rare, both below-ground and surface blowouts have been documented in Texas, Louisiana, Ohio, Pennsylvania, Colorado, and Wyoming in the United States. They can occur in the well where the problem originates or in neighbouring wells, including water wells. Seepage of any surface spill from a blowout can also lead to groundwater contamination.

Some incidents may take place during drilling, when the borehole encounters an over-pressurized, highly permeable formation. Pressure within the rock formation then pushes gas or liquid into the well and out to the surface. Fortunately, although some shale formations can be over-pressurized, most have very low permeability, which by definition restricts the flow. Note that pressure measured in the Green Point shale was found to be normal to slightly elevated (*see* section 2.3.2.3).

Problems can also develop during hydraulic fracturing. If the targeted rock formation does not fracture as intended, the elevated pressure being applied may force the fracturing fluid into other pathways since it cannot penetrate into the rock (Healy, 2012). In addition to the originating well, these pathways may include natural connections (for example, permeable layers or faults and other areas of weakness) to nearby wells that are not designed to cope with these high pressures. Affected wells may include other oil and gas wells or artesian wells used for drinking water.

For example, a recent blowout from a Chesapeake Energy Corp. well in Wyoming resulted when gas leaked from the Niobrara Shale up into a shallower, more permeable formation (Royal Society and Royal Academy of Engineering, 2012). This highlights the importance of knowing the location and status of abandoned wells in western Newfoundland. Although the number of historic wells in Newfoundland is low, it would pose a concern if development were in close proximity to a historic well.

To avoid blowouts, a multi-barrier pressure-control system is used. The density of the drilling mud can be adjusted based on expected formation pressures. By providing a certain weight of fluid in the well, the drilling mud can prevent pressurized fluids from entering the wellbore. Wells are also equipped with a special sealing assembly called a blowout preventer. This, along with appropriate surface casing and proper cementing provide additional controls (King, 2012).

4.3.2 PREVENTING LEAKS

Most of the reported incidents of contamination of groundwater and surface water have been the result of improper wellbore construction and are not directly related to hydraulic-fracturing treatment itself. The use of good-quality materials and their diligent installation are crucial for preventing leaks.

Industry best practices include quality standards for the design and installation of wells in preparation for hydraulic fracturing. This includes creating a continuous cement barrier to protect groundwater (*see* Figure 24) and developing remedial plans to be activated in the event that a wellbore is compromised. The quality of the casing and the quality of the cement used to fix the casing in place are both critical to safeguarding shallow-level aquifers from contamination by drilling and hydraulic fracturing fluids (Massachusetts Institute of Technology, 2011).

4.4 CHEMICAL DISCLOSURE

The additives used in a hydraulic fracturing fluid are a blend of common chemicals (*see* Figure 25 and Table 6). They have two primary functions: to open and extend the induced fracture system, and to transport the proppant down the length of the fractures to maintain permeability. Additives also perform critical safety functions such as controlling bacterial growth and inhibiting corrosion to help maintain well integrity. A portion of the additives are recovered in the water that flows back after hydraulic fracturing is completed – from 15% to 80% depending on specific conditions. The remainder is recovered once a well is brought into production and begins pumping fluids from the zone that was fractured (Cardno Entrix, 2012; U.S. Environmental Protection Agency, 2010).

To reassure Canadians about the safe application of hydraulic fracturing technology, members of the Canadian Association of Petroleum Producers (CAPP) have agreed to disclose all fracturing fluid additives including the constituent ingredients listed on each additive's Material Safety Data Sheet (Canadian Association of Petroleum Producers, 2013). Ingredients that must be listed on the MSDS are identified by federal law. CAPP's voluntary well-by-well disclosure of fracturing fluid additives includes: (a) the trade name of each additive and its general purpose in the fracturing process; (b) the ingredient's name and the Chemical Abstracts Service number, unless it is considered a trade secret, for each chemical ingredient listed on the Material Safety Data Sheet of an additive; and (c) the concentration of each reportable chemical ingredient (Canadian Association of Petroleum Producers, 2013).

Some of the concerns about the chemical content of hydraulic fracturing fluids reflects the fact that companies that operate in deregulated market economies (for example, in the United States) have the option of keeping fluid formulas a trade secret to gain competitive advantage. However, in Canada, most provinces that have active shale reservoir development require full disclosure of the chemical additives. Note that as part of its review of guidelines and best practices for hydraulic fracturing, the Government of Newfoundland and Labrador will consider requiring full disclosure of all additives.

4.5 WATER SOURCING AND MEASUREMENT

Supplying water to a long-term, commercial-scale hydraulic fracturing program is a significant issue because very large volumes of water are required over the lifespan of the operation. This is clearly a challenge with small or depleted watersheds. The volume of water required for an operation varies widely, ranging from 3500 cubic metres to 70 000 cubic metres of water per well depending on the geological characteristics of the reservoir. A typical multi-stage shale development uses 3500–10 000 cubic metres of fracture fluid (Canadian Society for Unconventional Gas, 2013). To put this volume into perspective, a 35-acre cranberry bog in Newfoundland would use about 64 000 cubic metres at harvest time. Note that a cubic metre is equivalent to 1000 litres.

This large range of required water volume also reflects the variation in lifespan of a well, with some operations lasting for a matter of days and others for many years (Massachusetts Institute of Technology, 2011). Each shale play is unique, as are the water resources of each region. Water-use policy and regulation varies widely among North American jurisdictions, just as well engineering varies with the geology of each play and with the characteristics of nearby surface water and groundwater (Secretary of Energy Advisory Board, 2011a, b). In Newfoundland and Labrador, the Department of Environment and Conservation's Water Resources Management Division assesses each proposed development activity individually (*see* section 3.5).

The impact of the local extraction of water is greatest on the ecology and sustainability of water bodies with small catchment areas. However, there is also a sustained and significant impact on the environment, local infrastructure, and local communities when such very large volumes of water are collected from a local source. Other impacts result if water is provided from a distant source and transported to and from the drilling site over sustained periods of time. This can involve the construction of new roads to remote drilling sites as well as increased heavy road traffic and accompanying pollution in communities.

Western Newfoundland has abundant surface water and groundwater (AMEC Earth and Environmental, 2008). The impact on water resources can be mitigated by ensuring that water used for hydraulic fracturing purposes is measured and recorded and is taken from sustainable sources. Water-use monitoring can ensure no withdrawal limits are exceeded, will verify the sustainability of the water source, and will make water-use data available. In addition, using sea water or saline groundwater instead of fresh water in an exploration program in western Newfoundland would further mitigate concern over the protection of fresh water resources.

Recycling and reuse of hydraulic fracturing fluids can minimize demands on local water supplies. About 15–80% of the injected fracturing fluid flows back to the surface when a well is depressurized. In the Eagle Ford shale in Texas, for example, there is almost no flowback water from an operating well following hydraulic fracturing, but in the Marcellus shale, primarily in Ohio, New York, Pennsylvania, and West Virginia, the flowback water is 20–40% percent of the injected volume. There is an ongoing industry effort to recycle and reuse as much flowback waste water as possible (King, 2012; Royal Society and Royal Academy of Engineering, 2012). Research is also underway exploring the use of sea water instead of fresh water in hydraulic fracturing operations to lessen their environmental impact.

Determining the amount of fluid required, the amount of fluid that can be recycled (because of flowback), and whether sea water can be utilized instead of fresh water all require testing of the specific target formation, as each shale play is distinct. Until a test-case exploration well is drilled, it is impossible to determine the effect that local variations in geology will have on an unconventional well's water requirements. An exploration well represents a first attempt at fracturing the rocks with limited fracture distances extending from the wellbore. The amount of water required for such a test is relatively small – a fluid volume in the range of 300 cubic metres (300 000 litres) is typical.

4.6 WATER PROTECTION

One of the most widespread and widely reported environmental concerns about hydraulic fracturing operations is that of groundwater contamination. The potential risk to groundwater comes from two sources, the hydraulic fracturing fluid (water and chemical additives) and various types of related waste water including flowback water (King, 2012; Osborn and others, 2011; also *see* sections 3.2 and 4.7).

Contamination of groundwater from a well can occur in three ways: (a) Hydraulic fracturing fluid can migrate (percolate) along faults, permeable layers, or other channels of communication from the target formation to the surface. (b) Closer to the surface, defects in the well can allow leakage of the fracturing fluid or produced water. This could also occur in a conventional well. (c) At the surface, the handling or storage of fluids can result in a spill. The following sections look at each scenario in further detail.

4.6.1 PERCOLATION FROM FRACTURING AT DEPTH

Whether fracturing fluids can migrate from the fracture site at depth to pollute drinking water aquifers is of fundamental importance. Such a migration of fluid is not likely because the fractured shale is typically separated from groundwater by thousands of metres of impermeable rock layers. Nearly all freshwater resources are within the first 300 metres of the surface, but hydraulic fracturing typically occurs in shale at a depth of about 1000–3000 metres (*see* Figure 24 and also King, 2012).

Only a few peer-reviewed scientific studies have been published on this issue, but existing evidence shows that fracture fluids will not reach the groundwater table during the fracturing process itself (King, 2012). The forces used in hydraulic fracturing cannot fracture rock layers from depth all the way to the surface allowing the fluid to escape directly. The growth of fractures is very small at operating depth, usually 100–200 metres from the wellbore (Davies and others, 2012). This is not only predicted by computer models but has been confirmed by very sensitive seismic monitoring during fracturing. Further confirmation comes from a variety of tests to track fluids. These include using chemical tracers to track where the fracture fluid goes, monitoring the temperature readings in a well, and inspecting hydraulically fractured rock that is later recovered from of the well in what is called a “mine-back test” (Warpinski, 1985).

To date, there is no scientific evidence of long-term migration of fluids from past hydraulic fracturing. For example, the Barnett shale in Texas has been fractured for decades, and no leakage from a fracture network has been documented to date. This may reflect an insufficient passage of time, given that the flow rates are likely to be very slow (Healy, 2012); however, it supports the view that contamination over the long term is unlikely. The U.S. Department of Energy injected fracturing fluid laced with tracer chemicals into a drill site that was 2500 metres below the surface in the Marcellus shale of Pennsylvania. After a year of monitoring, a brief statement in 2013 reported “nothing of concern” in the findings to date; however, it also acknowledged that the results are too preliminary for a firm conclusion (U.S. Department of Energy, 2013b).

Note that none of this evidence should be confused with reported problems in places where the production of coal-bed methane is practiced. Unlike shale gas or shale oil hydraulic fracturing, which typically occurs at significant depths, coal-bed methane hydraulic fracturing occurs at much shallower depths, often at or just below the water table. Coal-bed methane operations do pose a potential risk for groundwater contamination. There are no known coal-bed methane resources in the Province of Newfoundland and Labrador.

4.6.2 LEAKAGE AND SPILLS

All scientifically studied and documented cases of groundwater contamination associated with hydraulic fracturing show that the contamination is related to leakages due to poor well-casing design or poor cement, and/or as a result of spillage of fracturing fluid or related waste water at the surface (King, 2012; Royal Society and Royal Academy of Engineering, 2012; U.S. Department of Energy, 2013a). *See* sections 4.3 and 4.7 for more information about these types of events.

4.6.3 SAFEGUARDS AND MONITORING

In order to safeguard the quality of groundwater and surface water, companies following current industry best practices (Canadian Association of Petroleum Producers, 2013) will test domestic water wells within 250 metres of shale gas, tight gas, and tight oil development. They also participate in broader, longer term regional programs of groundwater monitoring. Such studies establish the baseline characteristics of groundwater prior to development and then monitor for possible changes over time. The practice includes programs for testing existing industry wells, domestic wells, and natural springs with landowner consent. Companies also work with government and regulators to design and implement regional groundwater monitoring programs.

Collecting the necessary water-quality information requires the establishment of groundwater monitoring wells at the exploration site as well as regionally. The wells should access a range of depths beneath the ground surface, and at least some should be deep wells drilled to reach an important region known as the "base of the freshwater zone". Such an array of wells would cover the entire zone beneath the surface that has any potential to contain fresh water. It would position operators, regulators, and residents to understand the distribution and flow of groundwater, and it would provide baseline data on water quality as a basis for quality monitoring. The importance of establishing a baseline program cannot be overstated, because without it cause and effect may be difficult to establish if contamination is detected.

In its review of guidelines and best practices for hydraulic fracturing, the Government of Newfoundland and Labrador would build upon the Canadian Association of Petroleum Producers (2013) Operating Practice to guide the design and development of baseline groundwater testing programs and to monitor program quality. It should include testing of domestic water wells by individual operators, as well as regional programs run co-operatively by the provincial government and industry.

4.7 FLUID HANDLING, STORAGE, TRANSPORTATION AND DISPOSAL

Hydraulic fracturing operations necessarily involve large volumes of fluid, including fracturing fluids, formation water, flowback water, and other waste waters (*see* section 3.2). There would be obvious advantages to use "clean" hydraulic fracturing fluids free from chemical additives. If such fluids can be shown to be as effective as those with chemical additives, then many of the contamination risks associated with hydraulic fracturing could be reduced or eliminated (Healy, 2012). However, brine, naturally occurring radioactive materials, and other contaminants originate in the target shale, so issues of fluid handling, storage, transportation, and disposal would still be of concern.

For handling and storage, industry best practices are intended to reduce the likelihood that spills will occur, ensure quick and effective response to an accidental spill, and provide for site remediation (Canadian Association of Petroleum Producers, 2013). Processing presents additional challenges because the amount of additives, brine, and naturally occurring radioactive materials will be unique to each operation. The composition of waste waters will also likely change over the lifetime of a well. The most appropriate treatment will depend on the water's salinity, which is sometimes high because many shale units, including the Green Point shale, are marine deposits. Injection of waste water into disposal wells is another possible solution, though seismic risks need to be carefully assessed (*see* section 4.8).

4.7.1 PONDING AND RECYCLING

Some North American operators have chosen to pond waste water in man-made pools, allowing it to evaporate or having it transported away at a later date. Ponding can lead to elevated concentrations of the chemical additives and other contaminants, increasing the potential environmental impact if a leak develops. In some cases, due to poor design or poor maintenance, the evaporation ponds have leaked or conduits between the well and the pond have broken, leading to habitat and groundwater contamination (Healy, 2012).

Like ponding, recycling of waste water reduces the volume requiring disposal but can also concentrate contaminants, making eventual disposal more challenging. Diluting waste water with fresh water can make recycling more practical, although pre-treatment may be necessary. In developing guidelines for hydraulic fracturing, the Government of Newfoundland and Labrador should consider requiring tankage to isolate flowback fluids and other waste waters from the normal production stream. Requiring that these fluids be decontaminated or filtered before disposal should also be considered.

4.7.2 NATURALLY OCCURRING RADIOACTIVE MATERIALS

Another concern related to shale is that it can contain naturally occurring radioactive materials like potassium, uranium, thorium, and radium. These materials emit only low, background-level radiation, so their concentration does not ordinarily present a health hazard to anyone in a natural setting, for example, someone standing on a surface outcrop of shale.

Naturally occurring radioactive materials that become concentrated in the production process are then referred to as "technologically enhanced naturally occurring radioactive materials" or TENORM (U.S. Department of Energy, 2013a; U.S. Environmental Protection Agency, 2012.). It can be concentrated in sludges or scale deposits in pipes or tubing, filters, and similar components, creating a potential exposure risk for workers when the equipment is cleaned or when the collected waste is disposed of (U.S. Department of Energy, 2013a). In the United States, this type of low-level radioactive waste can only be accepted to a landfill if it meets certain limits for radiation. Materials exceeding the limits must be stored or disposed of in an approved manner (U.S. Department of Energy, 2013a). In Canada, federal regulations are similar (Canadian Nuclear Safety Commission, 2009).

4.8 SEISMOLOGY AND GEOLOGICAL RISK ASSESSMENT

The risk of earthquakes associated with hydraulic fracturing operations can come from two different activities: (a) the hydraulic fracturing process itself and (b) the disposal of waste fluids by pumping them into a well for permanent storage in deeply buried, porous rock formations.

4.8.1 SEISMIC ACTIVITY FROM HYDRAULIC FRACTURING

Hydraulic fracturing inherently involves some seismic activity. When the target shale is intentionally cracked during the hydraulic fracturing treatment, barely perceptible micro-seismic events occur. They can be measured with seismic receivers (geophones) placed at similar depth within one or more nearby wells (Healy, 2012). Micro-seismic events are generally less than magnitude 2 or 3 on the Richter scale, being about 1 million times weaker than seismic events that are typically felt by people. Micro-seismic measurements can be used to monitor the length of induced fractures. They help demonstrate that fracture treatments are not affecting shallower layers, such as those bearing freshwater aquifers (Davies and others, 2012).

The injection of large volumes of pressurized water at depth creates new stresses on the target rock formation. It addition to causing the intended artificial fractures, the process also affects the possibility that existing natural fractures will open or that existing faults will slip, causing earthquakes (Healy, 2012). Geophysical methods can be used to measure the state of stress in a borehole. Analyzing the stress makes it possible to predict how the hydraulic fracture treatment will interact with the rock's natural characteristics (Cardno Entrix, 2012).

Anomalous, low level seismic events have been reported from the Horn River Basin, British Columbia, between April 2009 and December 2011. The seismic events were recorded by the Canadian National Seismograph Network (CNSN) which measures seismic activity from monitoring stations located across the country, including Newfoundland. Subsequent investigation attributed the seismic activity to hydraulic fracturing in proximity to pre-existing faults, and made several recommendations to mitigate further events (BC Oil and Gas Commission, 2012).

Two recent earthquakes near Blackpool in the United Kingdom occurred following hydraulic fracturing operations. The injection of fluids likely caused movement along a previously unknown, permeable fault zone near the base of the well (de Pater and Baisch, 2011). The earthquakes in Blackpool were smaller than others related to human activity, such as coal mine collapse, smaller than past natural earthquakes in the region, and much smaller than natural earthquakes generally reported in the news media (Healy, 2012).

4.8.2 SEISMIC ACTIVITY FROM INJECTION OF WASTE FLUIDS

Waste fluids produced during shale gas or shale oil extraction are sometimes disposed of by injection into disposal wells. These injection wells can be in the target shale layer or in another rock formation far below the potable water table.

Recent studies have consistently concluded that the seismic effects of hydraulic fracturing are insignificant (Cardno Entrix, 2012; Ellsworth and others, 2012). However, those same studies have shown that under some conditions the injection of fluids into wells for disposal can induce small tremors, less than magnitude 3 or 4 on the Richter scale. These earthquakes are generally undetectable by humans (Majer and others, 2007; Nicholson and Wesson, 1990), but some have resulted in relatively minor damage to man-made structures. Disposal is more problematic than hydraulic fracturing (Zoback, 2012) because disposal involves injection of large volumes of fluid over longer periods of time and allows greater fluid pressures to build up within the host rock.

Studies have shown that there is an apparent correlation between earthquakes and deep injection of waste water in disposal wells when the injection zones occur near faults. For example, earthquakes in the Fort Worth-Dallas area were likely caused by fault movements close to injection wells (Frohlich and others, 2010; U.S. Department of Energy, 2013a, b).

As an unconventional oil or gas field is developed, an increase in hydraulic fracturing activities can lead to the need for increasing numbers of disposal wells. This in turn could lead to increased potential for related earthquakes and perhaps an increase in their severity (U.S. Department of Energy, 2013a, b). For other approaches to the treatment of the waste waters from shale gas and shale oil operations, *see* section 4.7.

4.8.3 MANAGING SEISMIC RISK

Operators need to minimize the risk of seismic events that might be triggered by their operations and avoid geological conditions that would adversely affect the outcome of their fluid injection activities. A recent publication by the U.S. National Research Council outlines an approach for reducing the seismic risks of underground disposal. In following this approach, operators review their plans for injection in light of available information such as the history of seismicity in the region, details of the local geology, and available data on regional stress (National Research Council, 2012; Royal Society and Royal Academy of Engineering, 2012).

Zoback (2012) outlines other specific ways to lessen the seismic risk of unconventional hydrocarbon operations. They include avoiding injection into active faults or faults in brittle rock and minimizing pressure changes at depth by using highly permeable rock formations for disposal. High permeability allows for the storage of large volumes of fluid without significant pressure changes in the rock formation. The guidelines also include establishing a local seismic monitoring network around the injection site to register any seismicity that may occur. If seismicity is detected, it is important to have plans in place for reducing the injection rate or even shutting down the injection process entirely if reduced rates still lead to seismic activity.

4.9 AIR-QUALITY MANAGEMENT

Hydraulic fracturing fluid and related waste waters can emit natural gas and other contaminants to the atmosphere, including chemical additives from the fracturing fluid and vapours from the shale formation. Methane gas may be emitted by the hydraulic fracturing process, but there is an ongoing debate about whether the amount is more or less than from conventional gas operations (Cathles and others, 2011; Howarth and others, 2011). If methane leakage is high, then shale gas operations have the potential for a larger greenhouse gas footprint than coal (Healy, 2012).

Because of the risk to air quality and the atmosphere, industry best practices aim to limit air pollution and minimize greenhouse gas emissions during the completion and testing of hydraulically fractured wells. Conserving petroleum is another part of a sound air-quality strategy. Operators who follow best practices know all the potential emission sources in their operations. They predict and then monitor emissions so that they operate within set limits. Even before the well begins operation, they keep emissions at a minimum by using "green completion" techniques to trap emissions that would otherwise have escaped or been flared off.

4.10 OVERVIEW OF RISKS

The limited number of published, peer-reviewed data available to date suggest that there is a low and probably manageable risk to groundwater from the process of hydraulic fracturing itself. The potential impacts on the atmosphere from associated methane emissions and the risks of increased seismicity appear to be very small but are less well known. The major cause for concern has been improper operational practices.

Many of the concerns associated with hydraulic fracturing seem to be misdirected, since the most common concern – contamination from the wellbore to local aquifers – has not been scientifically demonstrated. On the other hand, problems with specific types of reservoirs (for example, coal-bed methane hydraulic fracturing) and problems due to material failures (for example, substandard cementing of well components) have been documented and shown to be potential problem points.

Based on scientific and regulatory studies, two specific areas should be of greatest concern to the public and to regulators for mitigating risk associated with hydraulic fracturing: (a) regulation and quality control of the drilling and cementing of the well during its development, coupled with (b) the comprehensive management of waste water and other waste material produced by hydraulic fracturing programs.

Evaluation of potential impacts on the environment should be based on peer-reviewed, scientific analyses of quantitative data. Agencies responsible for regulating or monitoring the environmental impacts of shale resource development need to be at the forefront of this effort (Secretary of Energy Advisory Board, 2011a).

(This page intentionally left blank)

5. SUMMARY OF OPPORTUNITIES AND RISKS IN WESTERN NEWFOUNDLAND

This section provides a summary of opportunities and risks related to shale development in western Newfoundland. Key points from the report are summarized (5.1) and best practices recommended (5.2). The section concludes with a note recommending a future re-evaluation as technologies and issues continue to evolve (5.3).

5.1 KEY POINTS

1. Naturally occurring seeps and shows of hydrocarbons have been documented in western Newfoundland for over 150 years.

2. Available evidence indicates that the Green Point shale (part of the Green Point Formation of the Cow Head Group) of western Newfoundland has the potential to host shale oil and shale gas.

3. The Green Point shale of western Newfoundland differs from other unconventional shale plays currently being developed in North America because:

    a. Exploration for unconventional hydrocarbon resources in the shales of North American basins (for example the well-known Marcellus, Bakken, and Barnett shales) is targeting extensive, essentially flat-lying rock formations in which deformation is very slight and relatively simple. Thousands of wells, thousands of kilometres of seismic surveys, and a significant amount of research and testing support this type of shale play, much of the data having been collected during multiple cycles of exploration.

    b. The Green Point shale is part of an allochthon, meaning that the rocks have moved along faults, travelling very long distances from where they were originally deposited to their present location. The Green Point shale has been folded, locally thrust over itself, thickened or pinched out, and cut by many large and small faults due to multiple tectonic events that deformed the rocks.

    c. Because the Green Point shale is deformed, the rocks are complex – not a simple package in a consistently layered sequence as they are in other shale plays as described in item (a) above.

    d. Understanding of the distribution, detailed internal layering, and structure of the Green Point shale in the Port au Port region is incomplete. Although some outcrops are visible onshore, currently few details are known about the Green Point shale where it occurs below the surface. This is because of limited onshore mapping in the region, the scarcity of well data, and the structural complexity of the shale, which make seismic data resolution and interpretation difficult.

4. The geological complexity of the Green Point shale may be associated with increased uncertainty and risk when evaluating its potential as a target for hydrocarbon production using hydraulic fracturing.

    a. The increased complexity is associated with an increased need for data.

    b. Currently, limited information about rocks below the surface in the Port au Port area makes it difficult to quantify the risk using available data.

5. The acquisition of new data would provide valuable information making the shale more understandable, predictions about it more reliable, and risk assessment more accurate. New data could include:

    a. Modern seismic data, since much of the available conventional seismic data are below modern standard.

    b. New geological mapping of the area, since onshore mapping dates back to the early 1980s.

    c. Studies of the engineering properties of the shale and related rock formations, so that the effects of drilling and hydraulic fracturing in the Humber Arm Allochthon can be better predicted.

    d. Recovery and preservation of sections of drillcore rather than just drill cuttings from any new wells.

6. Hydraulic fracturing of exploration wells and multi-stage production wells normally occurs far below the freshwater table and aquifers. Freshwater resources are typically 1–3 kilometres above the target shale.

    a. However, in western Newfoundland there are known natural oil seeps, and the natural occurrence of hydrocarbons in fresh water has historically been documented. For that reason, it is particularly prudent to establish baseline studies of fresh water in the region, including studies of water wells, prior to any hydraulic fracturing. The baseline will allow identification of any potential development-related contamination.

    b. Obtaining knowledge about the location, amount, sources, and flow of surface water and groundwater for any proposed industrial site – including any that involve hydraulic fracturing – will help to mitigate the risk to groundwater.

7. Although there have been public concerns raised over the technique of hydraulic fracturing, other government jurisdictions in Canada have legislation, guidelines, and best practices established to monitor, evaluate, and allow its use (for example, Alberta, British Columbia, and Saskatchewan). Over 200 000 wells have been hydraulically fractured in Canada.

8. The available data suggest that the hydraulic fracturing process itself does not pose a significant environmental risk. However, there are potential risks to groundwater from poor well design

or construction, as well as from handling and storage of waste water from hydraulic fracturing operations.

9. In the event that stimulating an exploration well enabled successful recovery of commercial levels of hydrocarbons and further development was proposed, then additional assessment would be required.

    a. Issues to be considered would include the distances to residential properties or communities, well densities, and other risk factors.

    b. After assessment, the government and other regulatory agencies would either allow the proposal, modify it with appropriate controls or mitigations, or alternatively not allow it.

10. Not all basins in Newfoundland are as complex as the one containing the Green Point Formation, where rock layers have been broken and deformed multiple times. Onshore, the Bay St. George Basin and the Deer Lake Basin are comparable to basins of equivalent age in New Brunswick.

    a. The basins in New Brunswick are currently being targeted for shale gas and shale oil using the method of hydraulic fracturing.

    b. Preliminary interpretations, based on geological similarities with New Brunswick, predict that hydraulic fracturing of shale in the Bay St. George Basin and Deer Lake Basin could be successfully done and would carry a similar level of risk as shale reservoirs in New Brunswick.

11. Farther offshore (typically 5–10 kilometres from the west coast of Newfoundland) the Anticosti Basin has much more predictable geology than in the areas most targeted in the region to date. This is seen in seismic reflection data as well as gravity and aeromagnetic surveys.

    a. In these offshore regions, rock layers are similar to those in other basins of North America where the rocks have a more predictable, layer-cake arrangement.

    b. However, rocks of the Green Point shale are unlikely to be found in this part of the basin because the Humber Arm Allochthon does not extend that far. The only likely shale target in that part of the basin is the Black Cove Formation of the Goose Tickle Group.

5.2 ESTABLISHING BEST PRACTICE

Canadian regulators and the country's oil and gas industry are focused on the protection of groundwater and the environment and the mitigation of risk. In addition to Canadian Association of Petroleum Producers' Operating Practices for hydraulic fracturing (2013), the Petroleum Services Association of Canada (2013) has released a hydraulic fracturing code of conduct for the Canadian oil and gas services sector.

All Canadian jurisdictions regulate the interface between water, the environment, and industry. The application of evolving hydraulic fracturing techniques for unconventional oil and gas development is no exception. These regulations are set and administered by a number of federal and provincial ministries, including environment, natural resources, sustainable development, energy, transport, industry, and others. In addition, major producing jurisdictions have oil and gas regulatory entities – either provincial boards or the federal National Energy Board.

The following recommendations are based on available data, and the source material is listed in Appendix F, Further Resources. The intention is not to have an exhaustive list, but rather to form the basis for a more comprehensive Best Practices document. These suggestions are compiled from existing reports, principally Healy (2012), Royal Society and Royal Academy of Engineering (2012), and the Secretary of Energy Advisory Board (2011a and 2011b).

5.2.1 BASELINES AND MONITORING

1. National or local environmental agencies charged with monitoring the potential environmental impacts of hydraulic fracturing should be fully funded and equipped to carry out the necessary tasks. It appears from available data that the hydraulic fracturing process itself does not pose a significant environmental risk, but there are potential risks to groundwater from poor well design or construction (Secretary of Energy Advisory Board, 2011a) as well as from waste-water handling and storage.

2. Baseline studies of groundwater and of naturally occurring seeps and shows are needed before any drilling activity begins.

3. Understanding of the distribution and flow of local surface water and groundwater is needed in order to minimize the impacts on water resources through utilization of "green" industrial practices. Using sea water or saline groundwater for a hydraulic fracturing operation, instead of fresh water, is one such example of a "green" industrial practice.

4. In regard to environmental impacts, the open, direct, and rapid communication of all regulations, incidents, and best practices would help to combat rumours, misunderstandings, or inaccurate information about what is happening (Secretary of Energy Advisory Board, 2011b).

5.2.2 PROTECTING WATER RESOURCES

1. Companies or agencies planning to use hydraulic fracturing should be required to openly declare the exact chemical composition of the additives used in the injected hydraulic fracturing fluid, in addition to the volumes and concentrations of additives. This information should be reported to regulatory bodies and made publicly available.

2. Cementation of wellbore casings should be carried out to the surface, followed by down-hole pressure measurements and casing integrity tests to ensure the security of shallow groundwater.

3. Sourcing the large volumes of water required to support sustained hydraulic fracturing operations requires active monitoring and planned management of water supplies as well as the use of recycled water. Using sea water or saline groundwater can mitigate concern over the management of the fresh water resources.

4. Active and regulated management of waste water from the hydraulic fracturing process is critical, as this fluid poses one of the greatest tangible risks to the environment.

5.2.3 FURTHER RESEARCH

1. Continued research into the distribution, extent, and geological history of rock layers on and below the surface of western Newfoundland would enable better risk assessment.

2. Better geological understanding of the fracture networks produced by hydraulic fracturing operations is required, especially in more complex shale plays. Most existing shale gas and shale oil operations in North America involve rock layers with a simple, nearly horizontal nature, but the Green Point shale formation in the Humber Arm Allochthon is complexly folded and faulted on a variety of scales.

3. Because of the complexity noted in item (5.2.3.2) above, information obtained at one site cannot be easily applied to predict conditions at another site. Detailed, site-specific geological surveys must be conducted prior to drilling and well stimulation.

4. Research into removing or decreasing toxic additives from hydraulic fracturing fluids (ideally using just water and sand) should be explored.

5. Further research is needed into the treatment of flowback fluid and other waste water from unconventional hydrocarbon operations, with an emphasis on "green completions" that recycle and reuse these fluids.

5.2.4 PUBLIC DISCOURSE

1. Companies or agencies adopting a transparent approach to shale resource development should be encouraged and supported.

2. Media, corporate, scientific, and other publicly available material on unconventional hydrocarbon development and hydraulic fracturing should avoid excessive jargon and strive for unbiased clarity and accuracy.

3. Regulatory bodies may wish to consider wider issues raised by hydraulic fracturing, including how best to balance the public perception of risk and the intrinsic uncertainties involved in the science and engineering of rock layers below the surface.

5.3 THE NEED FOR CONTINUOUS IMPROVEMENT

The collection of data needed to inform responsible environmental management of oil and gas activities in Newfoundland and Labrador is not a one-time activity. Technologies for unconventional oil and gas development are continually evolving. Future experience with oil and gas activities in this province and elsewhere will require additional strategies and responses. For these reasons, the shelf life of the information in this report is limited. A re-evaluation of the management strategy for onshore to offshore oil and gas exploration is recommended within two years.

Re-evaluation will allow the province, its industries, and its citizens to obtain additional information about the oil and gas resources in Newfoundland and Labrador and further evaluate the feasibility of its extraction in a safe, responsible and sustainable manner. Any environmental monitoring activities required by the province will also contribute valuable information toward the future management of oil and gas activities.

APPENDICES

A. GEOLOGICAL TIME SCALE

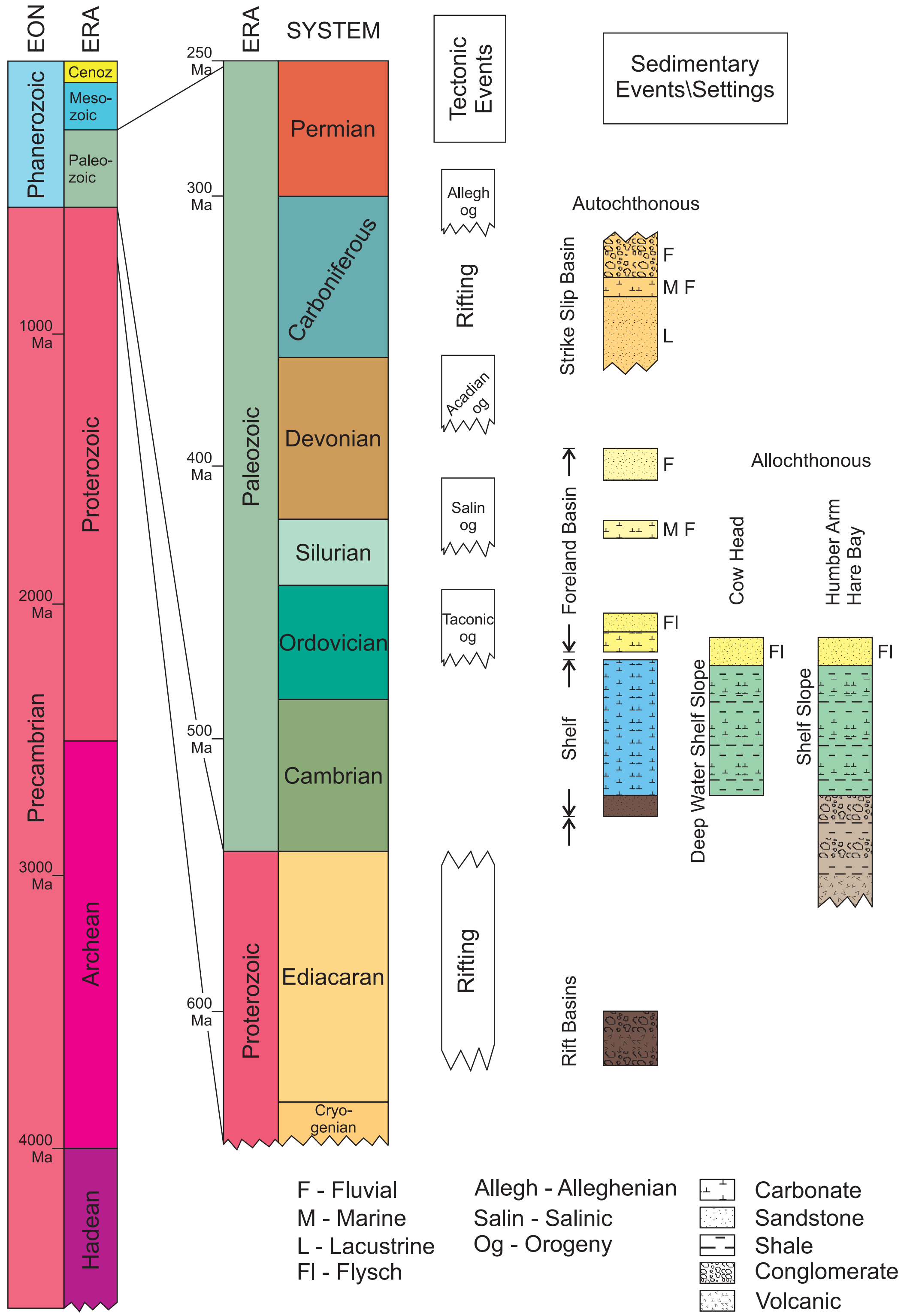


Figure A1. *Scientists have divided geological time into eras, periods, and other blocks of time to make it easier to talk about the deep past. Most of the events described in this report took place during the Paleozoic Era, which lasted almost 300 million years. The Paleozoic is divided into six geological periods based on significant changes in the fossil record such as extinctions or the sudden appearance of new species. For reference, the major tectonic events and rock units discussed in this report are also illustrated.*

B. DETAILS OF HYDROCARBON EXPLORATION IN WESTERN NEWFOUNDLAND

This appendix is based on the work of Fleming (1970); Fowler and others (1995); Hicks (2005); Newfoundland and Labrador Department of Energy (1989); Newfoundland and Labrador Department of Mines and Energy (2000); Newfoundland and Labrador Petroleum Directorate (1982) and Waldron and others (2012). It provides details about the history of hydrocarbon exploration in western Newfoundland and is organized by region, from south to north. *See* Table B.1 for a summary of wells drilled and their status. Figures 6 and 17 show the locations of wells.

B.1 PORT AU PORT AREA (ANTICOSTI SOUTH)

B.1.1 GARDEN HILL AND THE WESTERN PORT AU PORT PENINSULA

Hunt Oil of Canada and its partner PanCanadian were the first to test a deep onshore structure at Garden Hill, north of Cape St. George. They drilled the Port au Port #1 well at Garden Hill in the autumn and winter of 1994–1995 to a total depth of 4699 metres. The well encountered several potential reservoirs; the upper one, in rocks of the St. George Group, was hydrocarbon bearing. Two separate intervals within the hydrocarbon-bearing zone flowed 1528 and 1742 barrels per day of high quality, light oil and 2.6 and 2.3 million cubic feet per day of natural gas, respectively; water was also produced. An extended test on one of the intervals produced a total of 5012 barrels of oil over a 9-day period.

Hunt/PanCanadian and its partners followed this success by drilling the Long Point M-16 well at the tip of Long Point in 1995. Described as a stratigraphic test, the well had no significant hydrocarbon shows throughout its full length to a depth of 3810 metres, as reported in the final well report. Subsequent analysis (fluid inclusion studies and well log analysis) found evidence of hydrocarbon migration in the sedimentary rocks, and indicated the site has potential as an unconventional shale reservoir.

The success at Garden Hill encouraged the drilling in 1996 of a large anticlinal structure that had been identified by seismic data in the Gulf of St. Lawrence just southwest of Cape St. George. The offshore well, St. George's Bay A-36, was located approximately 6 kilometres southwest of the cape. Minor live oil and numerous bitumen occurrences were reported from the well and good porosity was noted in several formations as it drilled to 3240 metres true vertical depth.

The Long Range A-09 well was initiated in 1996 by Talisman and its partner Marathon Oil of Texas. It was located at Cape St. George approximately 3 kilometres south of the Port au Port #1 well. This well, which drilled to a measured depth of 3685 metres, deviated from onshore to offshore in order to test an extension of the large anticline drilled by St. George's Bay A-36. Upon completion, it was plugged and abandoned.

Canadian Imperial Venture Corporation (CIVC) became operator of the Hunt/PanCanadian Garden Hill project in 1999 and conducted additional pressure- and flow-testing of the reservoir zones in the Port au Port #1 well. CIVC re-entered the well in 2001, when its Sidetrack #1 well was drilled from the main wellbore in a northwesterly direction in order to penetrate the oil-bearing zone of the Garden Hill reservoir. The target reservoir was a porous dolostone containing caverns

Table B.1 Hydrocarbon wells drilled in western Newfoundland since 1990

Well Name	Type	Year	Class	Status	Northing[1]	Easting[1]	Total Depth[2]	Operator
Anticosti Basin								
Big Spring #1	Onshore	1997	Exploratory	Abandoned	5663981	572180	1397	Delpet Resources Ltd.
Finnegan #1	Onshore	2010	Exploratory	Suspended	5549336	456529	3130	Nalcor Energy Oil and Gas Inc.
Indian Head #1	Onshore	2001	Exploratory	Abandoned	5384012	394845	805	Canadian Imperial Venture Corp.
Lark Harbour WW #2	Onshore	1996	Stratigraphic	Abandoned	5438801	398605	123	Mobil
Little Port WW #3	Onshore	1996	Stratigraphic	Abandoned	5439996	396468	152	Mobil
Long Point M-16	Offshore	1995	Exploratory	Abandoned	5402657	368161	3810	NL Hunt Oil Corp. and PanCanadian Petroleum
Long Range A-09	Offshore	1996	Exploratory	Abandoned	5370511	333472	3685	Talisman and others
Man O'War I-42	Offshore	1998	Exploratory	Abandoned	5376200	362950	677	Inglewood Resources Inc.
Parsons Pond #1	Onshore	2004	Exploratory	Abandoned	5536408	449723	1062	Contact Exploration Inc.
Port au Port #1	Onshore	1994	Exploratory	Abandoned	5372856	335490	4699	NL Hunt Oil Company Inc.
Port au Port #1 ST #1	Onshore	2001	Step Out	Abandoned	5372857	335491	4054	Canadian Imperial Venture Corp.
Port au Port #1 ST #2	Onshore	2002	Step Out	Abandoned	5372857	335491	3482	Canadian Imperial Venture Corp.
Port au Port #1 ST #3	Onshore	2008	Development	Completed	5372856	335491	4256	PDI Production Inc.
Port au Port #2	Onshore	2001	Exploratory	Suspended	5372863	335498	503	Canadian Imperial Venture Corp.
Port au Port #3	Onshore	2001	Exploratory	Suspended	5372869	335505	30	Canadian Imperial Venture Corp.
Seamus #1	Onshore	2010	Exploratory	Suspended	5536434	449731	3160	Nalcor Energy Oil and Gas Inc.
Shoal Point 2K-39	Offshore	2008	Exploratory	Abandoned	5389201	364249	2740	Shoal Point Energy Ltd.
Shoal Point 2K-39 Z	Offshore	2008	Step Out	Abandoned	5389201	364249	36	Shoal Point Energy Ltd.
Shoal Point 3K-39	Offshore	2001	Exploratory	Suspended	5389201	364249	1745	Dragon Lance Mng. Corp.
Shoal Point K-39	Offshore	1999	Exploratory	Abandoned	5389192	364249	3035	PanCanadian Petroleum
St. Georges's Bay A-36	Offshore	1996	Exploratory	Abandoned	5365376	327991	3240	NL Hunt Oil Corp. and PanCanadian Petroleum
York Harbour #1	Onshore	1996	Exploratory	Abandoned	5435750	406350	299	Mobil
Bay St. George Basin								
Backstretch #2 (Hurricane #1)	Onshore	2005	Exploratory	Suspended	5344650	377162	876	Vulcan Minerals Inc.

Note: Wells drilled since 1990, as of October 2013. Wells are listed alphabetically by basin.
[1]Northing and Easting are UTM location coordinates using datum NAD 27. [2]Depths are in metres.

Table B.1 Continued

Well Name	Type	Year	Class	Status	Northing[1]	Easting[1]	Total Depth[2]	Operator
Bay St. George Basin (continued)								
Captain Cook #1	Onshore	2002	Exploratory	Abandoned	5361947	386780	605	Vulcan Minerals Inc.
Flat Bay #1	Onshore	1999	Exploratory	Suspended	5360239	384435	286	London Resources Inc.
Flat Bay #2	Onshore	2004	Exploratory	Abandoned	5359964	386697	845	Vulcan Minerals Inc.
Flat Bay #3	Onshore	2005	Exploratory	Suspended	5360085	384422	370	Vulcan Minerals Inc.
Flat Bay #5	Onshore	2006	Exploratory	Abandoned	5359952	386152	719	Vulcan Minerals Inc.
Flat Bay 93-101 #1	Onshore	2000	Exploratory	Abandoned	5359990	386625	671	American Reserves Energy (Canada) Corp
Flat Bay Test #1	Onshore	1996	Stratigraphic	Abandoned	5360263	384388	154	Vulcan Minerals Inc.
Flat Bay Test #2	Onshore	2009	Test Hole	Abandoned	5360126	384337	214	Vulcan Minerals Inc.
Flat Bay Test #3	Onshore	2009	Test Hole	Abandoned	5359954	384485	249	Vulcan Minerals Inc.
Flat Bay Test #4	Onshore	2011	Test Hole	Abandoned	5359906	383431	184	Vulcan Minerals Inc.
Flat Bay Test #5	Onshore	2011	Step Out	Abandoned	5360935	383174	350	Vulcan Minerals Inc.
Flat Bay Test #6	Onshore	2011	Test Hole	Abandoned	5358294	384555	202	Vulcan Minerals Inc.
Flat Bay Test #7	Onshore	2011	Test Hole	Abandoned	5357591	384810	220	Vulcan Minerals Inc.
Flat Bay Test #8	Onshore	2011	Step Out	Abandoned	5360379	385041	349	Vulcan Minerals Inc.
Flat Bay Test #9	Onshore	2011	Step Out	Abandoned	5360177	383667	159	Vulcan Minerals Inc.
Gobineau #1	Onshore	2012	Exploratory	Completed	5357531	384992	445	Vulcan Minerals Inc.
Red Brook #1	Onshore	2006	Exploratory	Abandoned	5347385	370116	187	Vulcan Minerals Inc.
Red Brook #2	Onshore	2009	Exploratory	Suspended	5347380	370104	1965	Vulcan Minerals Inc.
Robinsons #1	Onshore	2009	Exploratory	Suspended	5343074	379783	3560	Vulcan Minerals Inc.
Storm #1	Onshore	2005	Exploratory	Abandoned	5363638	393461	881	Vulcan Minerals Inc.
Whip #1 (Hurricane #2)	Onshore	2005	Exploratory	Suspended	5347196	375855	935	Vulcan Minerals Inc.
Deer Lake Basin								
Werner Hatch #1	Onshore	2010	Exploratory	Suspended	5451555	474810	442	Deer Lake Oil & Gas Inc.
Western Adventure #1	Onshore	2000	Exploratory	Suspended	5456494	482818	1879	Deer Lake Oil & Gas Inc.
Western Adventure #2	Onshore	2002	Exploratory	Suspended	5462724	485022	1326	Deer Lake Oil & Gas Inc.

Note: Wells drilled since 1990, as of October 2013. Wells are listed alphabetically by basin.
[1]Northing and Easting are UTM location coordinates using datum NAD 27. [2]Depths are in metres.

and other voids, part of the upper Aguathuna Formation known from the Port au Port #1 well. The dolostone was absent or missed, and only tight limestone was encountered. However, minor oil shows were present in dolostone of the lower Aguathuna Formation. While CIVC had the drill rig mobilized, they drilled two additional wells in close proximity to Port au Port #1. Port au Port #2 and Port au Port #3 were drilled to set casing and allow for future exploration (*i.e.*, by re-entering the wells) should it be warranted. No further exploration has been done to date on these wells.

Sidetrack #2 well was drilled during the summer of 2002 by Canadian Imperial Venture Corporation in a northeast direction from the original Port au Port #1 well. It encountered oil flows of 195 barrels per day and natural gas flows of 1.2 million cubic feet per day with no water production. This sidetrack was tested for an extended period in 2006–2007, when it produced over 3500 barrels of oil and 15 million cubic feet of gas. In 2008, PDI Production Inc. drilled Port au Port #1 Sidetrack #3 and recovered over 14 500 barrels of oil during subsequent flow testing and intermittent production.

Overall, approximately 40 000 barrels of oil and 135 million cubic feet of gas have been produced from the original Port au Port #1 wellbore and sidetracks, and the Port au Port Peninsula has attracted the greatest interest from exploration companies. However, sustained commercial production has remained elusive.

B.1.2 SHOAL POINT

Three wells were drilled on Shoal Point on the north shore of the Port au Port Peninsula to evaluate an attractive, deep carbonate play of Cambro-Ordovician age, which had been recognized on a regional 2-D seismic survey beneath Port au Port Bay. This tempting fault-bounded, large anticlinal structure of Lower Paleozoic carbonates beneath West Bay was targeted in 1999 by the Shoal Point K-39 well on the tip of Shoal Point (adjacent to the 1965 Shoal Point #1 drill site) by Pan-Canadian Petroleum and partners Hunt Oil, Mobil, and Encal Energy. The well was directionally drilled to a depth of 3035 metres to test the large structure. It produced only water and was abandoned, and it remains unclear if the intended target was achieved.

Further exploration of the rock layers beneath Port au Port Bay north of Shoal Point followed from the same drill site on the point in 2008. Enegi Inc. and partner Shoal Point Energy Ltd. drilled the 2K-39 well and sidetrack 2K-39Z to target the same carbonate structure beneath the bay in the region covered by exploration licence EL1070. No economic hydrocarbons were identified in St. George Group carbonate, but significant shows of gas were encountered in the intermediate hole section while drilling through the Green Point shale of the Humber Arm Allochthon.

Shoal Point Energy and partners returned to the Shoal Point Peninsula in 2011 to test the Green Point Formation oil-in-shale play. The Shoal Point 3K-39 well reached a depth of approximately 1745 metres before being suspended due to rig and hole problems.

B.1.3 OTHER DRILLHOLES IN THE PORT AU PORT AREA

The Man O'War I-42 well near Campbell's Creek on the southern Port au Port Peninsula was drilled by Inglewood Resources in 1998 to evaluate the hydrocarbon potential of a faulted, anticlinal structure located beneath St. George's Bay. The well was drilled to a depth of 676.7 metres and was terminated due to technical problems encountered while drilling thinly bedded shale and carbonate of the Labrador Group. No hydrocarbon shows were noted in the drilled section.

North of Stephenville, at Black Duck Siding, the Indian Head #1 well encountered approximately 805 metres of Precambrian basement rock and was terminated in early 2002 by Canadian Imperial Venture Corporation.

B.2 BAY OF ISLANDS (ANTICOSTI CENTRAL)

The area of the Bay of Islands and the coastal outcrops southward to Serpentine River are host to a number of dead oil shows. The area lies adjacent to a major offshore structure identified using seismic reflection surveys of deeply buried Lower Paleozoic carbonate rock. Known as the Ptarmigan structure, it was first discovered by Mobil Oil Canada. The drilling in this area by Mobil Oil Canada Properties was intended as a stratigraphic test primarily to evaluate source and reservoir rocks in the Humber Arm Allochthon.

The first test hole, York Harbour #1, was cored to a depth of 299.3 metres true vertical depth in 1996. It penetrated multiple, stacked, sequences of greenish-grey, fine- to coarse-grained sandstone to pebbly sandstone with lesser pebble conglomerates and shale, all belonging to the Lower Cambrian Blow Me Down Brook Formation of the Humber Arm Supergroup. Poor to fair porosity in some sandstone beds invariably exhibited a weak to good, pale brown oil stain; numerous cross-cutting fractures commonly contained both calcite and pyrobitumen (solid hydrocarbon deposits). Fluids extracted and analyzed from the well indicate a medium-density oil.

Mobil Oil Canada Properties also drilled three shallow water wells in the communities of York Harbour, Lark Harbour, and Little Port to collect geological information and evaluate the potential of the source rocks in the area. Hole stability problems in York Harbour Water Well #1 forced it to be abandoned at 50.3 metres, but dark shale was encountered in the bottom of the 123.4-metre Lark Harbour Water Well #2. The shale averaged 0.80% total organic carbon with a range from 0.6% to 1.5%. Using the fossil-based Acritarch Alteration Index to assess maturity, the results ranged from 2.3 to 2.7, implying that the rock layers are within the oil window. Red shale encountered throughout Little Port Water Well #3 (152 metres) had very low total organic carbon values (below 0.3%) and Acritarch Alteration Index values were high, ranging from 2.7 to 3.4. This suggests the red shale is mostly overmature for oil and falls within the zone for condensate or dry gas.

B.3 NORTHERN PENINSULA (ANTICOSTI NORTH)

B.3.1 PARSONS POND

The presence of numerous oil seeps and a past history of oil-producing wells at Parsons Pond and St. Paul's Inlet – within and north of Gros Morne National Park – provided this area on the Great Northern Peninsula with a strong case for exploration. Onshore surface seismic lines evaluated in the Parsons Pond area by the Government of Newfoundland and Labrador, Nalcor Energy, and others showed several possible prospects.

The prospects included a large thrust structure lying within rocks of the Cow Head Group, interpreted to be an uplifted slice of Lower Paleozoic carbonate shelf. This potential target was drilled in the Parsons Pond #1 well by Contact Exploration of Calgary and its partners in 2004. However, they encountered a fault zone prior to reaching the planned drill depth and drilling was suspended.

Nalcor Energy acquired a majority interest in three properties located immediately north of Gros Morne National Park in 2009. Nalcor Energy and its partners initiated the Seamus #1 well in the southern permit in February 2010 and commenced Finnegan #1 on the northern permit in September 2010. Partners in the well announced a number of gas zones had been penetrated in the upper sections of both wells.

B.3.2 OTHER WELLS

Delpet Vinland drilled the Big Springs #1 well in May 1997 in the Hare Bay area. The well targeted an anticlinal trap located within a complex fold-and-thrust structure. Within the Ordovician shelf carbonate layers, they targeted porous dolostone as well as porous reservoirs in the overlying sandstone sequences. Drilled to a total depth of 1397 metres, the core consisted only of Cambrian carbonate from the Port au Port Group. Very minor gas shows were encountered.

B.4 CARBONIFEROUS BASINS

Western Newfoundland has two Carboniferous basins (*see* section 1.2.5), the Bay St. George Basin and the Deer Lake Basin. Each has a history of hydrocarbon exploration.

B.4.1 BAY ST. GEORGE BASIN

Indications of hydrocarbons were first noted in the Bay St. George Basin in the late 1800s, and the first live oil shows were discovered by the Newfoundland Department of Mines and Energy while drilling the Flat Bay gypsum prospect in 1957 (McKillop, 1957). The drilling encountered liquid hydrocarbons slowly seeping from a conglomeratic sandstone below the gypsum. It also encountered pockets of gas in the gypsum itself. The natural gas encountered was flared off before drilling was continued.

This discovery made the Flat Bay anticline a prime target for follow-up exploration 40 years later. Improved understanding of Carboniferous basins in the Maritime Provinces and the discovery of a new oil and gas field (the McCully Gas Field) in the Moncton Basin in New Brunswick in 2000 led to exploration in other areas of the Bay St. George Basin. The primary exploration company in this pursuit was Newfoundland-owned and -operated company, Vulcan Minerals.

The first concerted effort to explore in the basin, however, targeted the large Anguille Anticline in the Anguille Mountains. The exploration well, Union Brinex Anguille H-98 was drilled in 1973 to a total depth of about 2300 metres but reported no gas, oil, or worthwhile reservoir beds.

Petroleum exploration then remained dormant until 1996 when London Resources Inc. (Vulcan Minerals Inc.) drilled a 154-metre test hole (Flat Bay Test #1) adjacent to the location of the hydrocarbon-bearing Flat Bay gypsum site. Encouraged by the presence of liquid hydrocarbons in this test, which confirmed earlier work by the Department of Mines and Energy, Vulcan Minerals Inc. drilled their Flat Bay #1 well in 1999 to further evaluate the Carboniferous conglomerate. They reported the presence of sweet, light crude having an API gravity of 34° and sulphur content less than 1%. The company also reported that geophysical logs suggested zones in the conglomerate that might be commercially productive upon reservoir stimulation. A third well drilled by Vulcan Minerals (Captain Cook #1) encountered crystalline basement rocks at the bottom of the hole, which was terminated at 605.2 metres after penetrating approximately 70 metres of anhydrite containing localized, oil-stained fractures. Flat Bay #2 well, drilled by Vulcan Minerals in 2004 to a total depth of 845 metres, encountered 115 metres of conglomerate including a rock formation they interpreted to be oil-bearing with low permeability and a gross thickness of 100 metres.

In 2000, American Reserve Energy (Canada) Corporation drilled their Flat Bay 93-101 #1 well adjacent to Vulcan land positions, presumably with the same target in mind. The well was abandoned due to drilling problems before reaching their target horizon. Flat Bay #3 was drilled in 2005 close to the original Flat Bay #1 well. Flat Bay #5 well was drilled as a further test of the oil-bearing Flat Bay structure in following years, along with the Red Brook #1 well. All these wells were plugged and abandoned, the Red Brook #1 well because it encountered drill-related problems before it reached its targeted depths.

In 2005, Vulcan Minerals also turned its attention to the middle of the basin. Seismic reflection data had shown a deep basin sequence thought to contain lake deposits of shale that might be organic-rich and thermally mature. This model was based on comparison to basin studies and exploration in New Brunswick, where there are similar rock types of the same age. Three holes (Storm #1; Backstretch #2, a.k.a. Hurricane #1; and Whip #1, a.k.a. Hurricane #2) were drilled over structures identified from the seismic surveys. All wells except Storm #1 had oil and/or gas shows. The hydrocarbons observed in Whip #1 and Backstretch #2 wells, although minor, are significant because they suggest that the petroleum system encountered around the northern extremity of the Flat Bay Anticline may be much larger than originally thought or that a second petroleum system may exist in the region.

Vulcan Minerals drilled two shallow core holes into their Flat Bay structure in 2009, with the aim of studying fracture orientation patterns as a prelude to future stimulation work in the area. This was followed by Vulcan-Investcan Robinson's #1 well, which reached a depth of 3600 metres, and Red Brook #2 well, which reached a depth of 1960 metres. Flat Bay #4–9 wells and Gobineau #1 exploration well were drilled more recently, in 2011–2012.

B.4.2 DEER LAKE BASIN

Gas seeps and albertite (a solid form of black oil) were discovered in a paleo-cavern north of Deer Lake, near the edge of the Deer Lake Basin and has encouraged exploration of its Carboniferous rock layers. The first petroleum exploration took place in the early 1900s near the town of Nicholsville, where a well encountered natural gas that is still seen bubbling from its drill casing. The primary target was believed to be a lake deposit of shale formed during a second stage in the evolution of the basin.

A promising anticlinal structure, the Big Falls–Little Falls anticline, is located east of Deer Lake. It was the target of Claybar Uranium and Oil Ltd. and Newkirk Mining Company, who drilled Claybar #1 in late 1955. The well, which was drilled to 473.8 metres, had minor gas shows. Claybar #2 well, situated approximately 19 kilometres to the south of Claybar #1, was drilled to test the proposed extension of the anticlinal structure; it was terminated at 847.6 m before reaching its target objective. Claybar #3 well, located approximately 4 kilometres southeast of Claybar #1, was drilled to a depth of 730.5 metres and encountered only minor amounts of gas in the shale. Their final well in the area, Claybar #4, was located 5.6 kilometres northeast of Little Falls on the Humber River. It was drilled to 152.4 metres before being terminated without reaching its target objective; there were no hydrocarbon shows.

Forty-five years later, the current round of petroleum drilling began in 2000–2001, when Newfoundland-based, junior petroleum exploration company Deer Lake Oil and Gas Ltd. targeted a seismically defined, fault-bounded structure east of Deer Lake. They continuously cored the Western Adventure #1 well to a depth of 1879 metres and encountered 1350 metres of locally porous, thinly to thickly bedded conglomeratic sandstones that underlie the lake-derived rocks of the basin. These sandstones included significant reservoir horizons that flow-tested gas at a maximum rate of 100 000 cubic feet per day. The well also produced minor amounts of condensate. This well was re-entered in 2005, stimulated and flow-tested.

Western Adventure #2 well was drilled by Deer Lake Oil and Gas in early 2002 approximately 6 kilometres to the north-northeast of Western Adventure #1. It lies in a separate fault block within the basin, which contains a complex fault structure often associated with hydrocarbon traps. This well, drilled to a depth of 1325 metres, surprisingly contained only 321.5 metres of conglomeratic sandstone as compared to the 1350 metres encountered in Western Adventure #1. Minor gas shows were encountered throughout the well, which at its base penetrated 563.5 metres of Lower Paleozoic shelf carbonate. This well is currently suspended for “possible re-entry, stimulation and testing”. In 2010, Deer Lake Oil and Gas drilled the relatively shallow Werner-Hatch well to evaluate the unconventional and tight reservoir rock hydrocarbon potential of the Rocky Brook Formation.

C. REGULATORY ENVIRONMENT

With any industrial development there will be an environmental impact. The key is balancing the potential benefits of industrial activity with the potential environmental risks. In jurisdictions with appropriate guidelines and regulations, the use of stimulation techniques such as hydraulic fracturing has proved to be a manageable risk. Specific measures required to manage the risk acceptably will vary depending on local conditions. This section briefly describes the current regulatory environment for oil and gas operations in Newfoundland and Labrador.

The Canada–Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act sets out the mechanism for joint federal–provincial management of the Newfoundland offshore area through the Canada–Newfoundland and Labrador Offshore Petroleum Board (CNLOPB). The Act also defines the methods for obtaining exploration and production rights, the requirements for safety, resource conservation, and environmental protection, and the activities that may be regulated.

The Act is mirrored in federal statutes. Regulations that govern offshore oil and gas exploration include: a) Canada–Newfoundland and Labrador Oil and Gas Spills and Debris Liability Newfoundland Regulations; b) Certificate of Fitness Newfoundland Regulations Offshore Area Oil and Gas Operations Regulations; c) Offshore Area Petroleum Geophysical Operations Newfoundland Regulations; d) Offshore Area Registration Regulations; and e) Offshore Petroleum Drilling and Production Newfoundland and Labrador Regulations, 2009.

The Petroleum and Natural Gas Act and subsequent regulations define how the rights to explore for and develop oil and gas properties on land may be obtained and maintained, how areas may be assigned for exploration, the scope with which government may regulate activity, and the various royalties that may be due. It includes: Petroleum Regulations, Petroleum Drilling Regulations, Oil Royalty Regulations, Royalty Regulations and Guidelines.

The provincial Department of Natural Resources is currently conducting a jurisdictional review and a review of Hydraulic Fracturing Best Practices or Guidelines for Oil and Gas Operations. These best practices or guidelines are designed to build upon existing regulations governing oil and natural gas industry activities in Newfoundland and Labrador. Their specific purpose is to ensure that hydraulic fracturing operations, should they be allowed onshore Newfoundland and Labrador, are conducted in a manner that maximizes safety, environmental protection, and resource conservation.

The Minister of Natural Resources has primary authority to regulate and approve petroleum exploration and production activities under the Petroleum and Natural Gas Act. The Minister of Environment and Conservation has broad legislative authority to regulate and approve activities that may adversely affect the environment and that involve the use of water. Because hydraulic fracturing is a petroleum activity that may have adverse environmental affects and involves the use of water, both ministers will have regulatory responsibilities respecting hydraulic fracturing. Oil and gas activities cannot proceed without approvals, and the granting of these approvals typically includes the authority to prescribe terms and conditions necessary to ensure the protection of the public interest.

The key principle the provincial government would adopt in regulating hydraulic fracturing operations, should these activities proceed, is risk mitigation. The Minister of Natural Resources will expect operators in Newfoundland and Labrador to ensure that risks are reduced to "as low as reasonably practicable". This principle requires operators to control risks. To do this they must adopt a systematic approach to risk identification and apply the practices of quality engineering to the design of their systems and risk solutions. In short, they are required to develop the most effective techniques and approaches available in order to address the risks posed by their operations. By assessing risk at an early stage, and by planning operations with mitigation of risks at the forefront, the negative impact of hydraulic fracturing operations can be reduced to meet the "as low as reasonably practicable" standard.

Due to the need for regular updates to the legislation, regulations, best practices, and guidelines for onshore and offshore petroleum activities, the websites for the CNLOPB, the Government of Newfoundland and Labrador, and the federal government are the best sources of up-to-date regulatory information:

- Department of Environment and Conservation http://www.env.gov.nl.ca/env
- Department of Natural Resources http://www.nr.gov.nl.ca/nr
- Canada-Newfoundland and Labrador Offshore Petroleum Board (CNLOPB) http://www.cnlopb.nl.ca
- Canada Oil and Gas Drilling and Production Regulations http://laws-lois.justice.gc.ca/eng/regulations/SOR-2009-315/index.html

In November 2013, the Department of Natural Resources announced that any applications seeking approval for oil or gas exploration or development that involved hydraulic fracturing would not be accepted pending a jurisdictional review, a geological review, and an opportunity for public engagement. That government position on hydraulic fracturing remains in effect today.

D. DEFINITIONS

***Note: Bold words** in definitions refer to other terms defined here.*

Additive: A substance or combination of substances composed of chemical ingredients and found in a hydraulic fracturing fluid. Each additive performs a certain function and is selected depending on the properties required. Also *see* **Proppant**.

Aeromagnetic survey: A common type of geophysical survey using a magnetometer aboard or towed behind an aircraft. The aircraft typically flies in a grid-like pattern while the magnetometer records tiny variations in the intensity of the magnetic field.

Allochthon: A large block of the Earth's crust that has moved a considerable distance from its place of origin, mainly due to tectonic compression and thus is found among rocks of unrelated origin. Allochthons are usually highly deformed. Compare to **Autochthon**.

Annular leak: A leak in the annulus, which is the space between the wellbore and the well casing, or between casing and tubing.

Anticline: An arch-like fold in rock layers, with the oldest rocks in the core. In petroleum geology, anticlines are significant because hydrocarbons can become trapped under the enclosing sides of the fold.

API gravity: A measure of the specific gravity or density of a liquid petroleum product, developed by the American Petroleum Institute and expressed in degrees API. Most values fall between 10°(more dense) and 70° (less dense).

Aquifer: A body of rock or unconsolidated sediment that is sufficiently permeable to conduct and store groundwater and to yield economically significant quantities of water into wells and springs.

Autochthon: A unit of the Earth's crust that remains in its place of origin. Compare to **Allochthon**.

Barrels of oil equivalent: A unit of energy based on the approximate energy released by burning one barrel of crude oil. In mixed oil and gas basins, often used to describe the energy resource potential of any given area in a single number.

Barrels of oil per day: A unit of measure for the flow rate of oil from any given well, oilfield, or resource area.

Barrier system: A well system designed to contain and isolate fluids within the well.

Base of groundwater protection: A calculated depth at which saline groundwater is likely to occur, generally the base of the deepest protected (non-saline groundwater-bearing) formation plus a 15-metre buffer.

Basin: An area of the Earth's crust that was once, or is now, a large regional depression and therefore a site of sediment accumulation. A formerly active basin may now be recognized as a closed geological structure in which sedimentary rock layers tilt toward a central location, and where youngest layers at the centre are partly or completely ringed by progressively older rocks.

Bedrock: A solid, continuous body of rock that is part of the Earth's crust. Bedrock is sometimes exposed on the surface and sometimes concealed beneath soil, glacial deposits, ice, or other surface material.

Biogenic: Produced by living organisms or biological processes.

Biomarker: In petroleum geology, a complex organic molecule or characteristic mixture of molecules that can be used to identify the source and history of a hydrocarbon sample.

Borehole log: *See* **Well log**.

Borehole geophysics: The science of recording and analyzing measurements of physical properties made in wells or test holes. Also *see* **Wireline log**.

Calcite: One of the common carbonate minerals and the most stable form of calcium carbonate ($CaCO_3$).

Casing string: A sequence of steel pipe segments designed to suit a specific wellbore and assembled end-to-end to line the wellbore. Once connected and lowered into the wellbore, the casing string is cemented in place.

Casing: Steel piping positioned in a wellbore and cemented in place to prevent the soil or rock from caving in. It also serves to isolate fluids, such as water, gas, and oil, from the surrounding geological formations.

Cement job: The application of a liquid slurry of cement and water to various points inside or outside the **casing** in a wellbore.

Chemical ingredient: In the context of hydraulic fracturing, a discrete chemical constituent that is required by law to be listed on the **Material Safety Data Sheet** of an **additive**. Each ingredient has its own specific name and identifying Chemical Abstracts Service number.

Coal-bed methane: Natural gas found within and around coal seams. The methane is sometimes made to flow from a well by pumping large volumes of water out of the coal-bed or seam to create a pressure gradient. Also known as coal-bed natural gas.

Completion: The process of preparing an oil or gas well for production once the well has been drilled, including installation of equipment needed for production.

Conventional hydrocarbon: In the oil and gas industry, a **play** where the source rock, reservoir, and seal rock are separate units. The petroleum is generated in one location, migrates through the rock system, and becomes trapped in a typically porous and permeable reservoir beneath an impermeable seal such as shale or salt. Examples include the Hibernia Oilfield.

Darcy: (millidarcy, microdarcy) In the petroleum industry, a widely used unit of permeability named after nineteenth century hydraulic engineer Henry Darcy. The darcy unit has dimensions of surface area.

Dead oil: Oil with little or no dissolved gas, either because the oil has been at low pressures or because the gas has slowly escaped over time. Compare to **Live oil**.

Density log: A type of **electric log** that measures the bulk density of a rock formation by bombarding it with emissions from a radioactive source and measuring the resulting gamma ray count. The bulk density can be used to determine porosity.

Dip: The measured angle of a rock layer, fault, or other tilted plane feature relative to a horizontal plane, ranging from 0° to -90°. Together with **strike**, it describes the orientation of the feature.

Dipole sonic log: *See* **Sonic log**.

Directional drilling: A drilling technique used to reach an underground location not positioned directly below, for example, from an onshore wellpad to an offshore target, by drilling at an angle from the surface location.

Disposal well: A well drilled to access a porous underground formation into which waste water is injected for disposal.

Domestic water well: An opening in the ground, whether drilled or altered from its natural state, for the production of groundwater used for drinking, cooking, washing, yard maintenance, or livestock.

Drill rig: The mast or derrick and related surface equipment of a well-drilling unit.

Drillstem test: A test often made on exploration wells in which one zone of the well is isolated, then fluids from that zone are made to flow into the drill string. The test can help determine the porosity, permeability, hydrocarbon potential, and other characteristics of the zone being tested.

Electric log: A type of **wireline log** that uses electrical wireline. The term refers to any log recorded on a wireline, whether it measures an electrical quantity or not. Electric logs include: resistivity logs, image logs, porosity logs, density logs, gamma ray logs, and sonic logs.

Emission: Air pollution discharge into the atmosphere, usually specified by mass per unit time.

Exploration: In the hydrocarbon industry, the process of identifying a rock formation and structure with the potential to produce hydrocarbon resources, and then drilling a borehole to assess the natural gas and/or oil resource.

Fairway: In petroleum geology, the trend along which a particular geological feature is likely to be found, based on the geological history of the area. In western Newfoundland, the extensional fairway is characterized by faults created during crustal extension early in the history of the Appalachian Mountains. The inversion fairway is characterized by opposite (inverted) movement along the faults, during later crustal compression.

Fault: A crack in the Earth's crust resulting in displacement of one side with respect to the other.

Flowback water: The flow of hydraulic fracturing fluid back to the surface after treatment is completed.

Fluvial: Refers to sedimentary rocks that are deposited by streams and rivers.

Flysch: A marine sedimentary deposit composed of shale, marl, sandstone or conglomerate.

Formation: In geology, sometimes used informally to refer to a series of layers or other collection of related rock units, but often used formally as part of a system for grouping and naming recognizable, mappable series of rock layers.

Formation integrity test: A type of **injection test** performed while drilling a well to determine whether the well will withstand the fluid pressures that will be required as the next section is drilled.

Formation water: Water that occurs naturally within the pores of rock.

Foreland basin: A low region in continental crust that develops adjacent and parallel to a mountain belt. The immense mass created by crustal thickening in the mountain belt warps the crust downward, forming a basin in which sediment worn from the mountains accumulates.

Fracture gradient: The pressure required to fracture a rock at a given depth. The required pressure increases with depth, since natural pressure in the Earth also increases and tends to prevent fractures from opening.

Fracturing fluid: A mixture of water and **additives** used to hydraulically induce cracks in a rock formation far below the surface.

Fresh water: Groundwater that has no more than 4000 milligrams of total dissolved solids per litre (unless otherwise defined by the jurisdiction). Compare to **Saline groundwater.**

Freshwater aquifer: An aquifer above the **base of groundwater protection** that contains total dissolved solids of no more than 4000 milligrams per litre.

Gamma ray log: A type of **wireline log** that records levels of natural radioactivity in the borehole, measured in API units (a radiation measure defined by the American Petroleum Institute). It is used to distinguish between sandstone and shale. Sandstone is usually rich in quartz, which is not radioactive, but shale emits tiny amounts of radiation from potassium-rich clay minerals containing trace amounts of uranium and thorium.

Gas in place: The entire volume of gas contained in a reservoir, without regard to how much is recoverable.

Gravity survey: A type of geophysical survey that measures slight variations in the gravitational field over an area of interest. The density of the Earth's crust affects the gravitational field locally, and rock types vary significantly in their density. Measurements of gravity therefore allow inferences about the distribution of rock layers below the surface.

Green completion: As defined by the U.S. Environmental Protection Agency (EPA) in the Clean Air Act, it is the best system of emission reduction for the oil and natural gas industry, also called reduced emission completions.

Groundwater: Water held in soil and rock formations below the Earth's surface. The top surface of groundwater is the "water table"; below it lies the "zone of saturation" in which water fills virtually all pores, voids, and other spaces. From this zone comes water for wells, seepage, and springs. Compare to **Surface water**.

Habitat: An area or type of environment with features able to support the needs of a plant, animal, or other organism. Its features include sources of food and water, shelter from adverse elements, and sufficient open space.

Horizontal drilling: A drilling procedure in which the wellbore is drilled vertically to a specific depth near the target rock formation and then angled through a 90° arc so that the producing portion of the well extends horizontally through the target. Also known as deviated drilling.

Hydraulic fracturing: A hydrocarbon production technology in which rock units below the surface are fractured by injecting **fracturing fluid** under pressure into a specially designed well in order to release hydrocarbon reserves that would otherwise not flow due to low rock **permeability**.

Hydraulic fracturing program: One or more stages of fracturing within a given wellbore.

Hydrocarbon: In petroleum geology, an organic compound consisting entirely of hydrogen and carbon in liquid or gaseous form.

Hydrogen index: As measured using **Rock Eval** technology, an index that measures the proportions of hydrogen and carbon in a rock. Because the proportions vary in different kinds of organic matter (for example, algae or plants), hydrogen index helps to indicate the origin of the rock's hydrocarbon. In combination with the **oxygen index**, it also indicates **thermal maturity**.

Image log: A type of electric **wireline log** that measures acoustic properties across the borehole wall. This is used to identify the presence and direction of rock fractures, as well as to understand the tilt of the rock layers.

Induced seismicity: Seismic events that can be attributed to human activity such as geothermal energy extraction, mining, dam building, and hydraulic fracturing.

Injection: The pumping of fluids into an underground formation for testing, hydraulic fracturing, or waste-water disposal.

Injection tests: Tests performed by pumping fluid (such as water or drilling mud) into a well and observing the effects of the induced pressure.

Kerogen: Insoluble organic matter occurring as large molecules in sediment and classified as Type I, II, III, or IV residue depending on its biological origins (marine/algal, mixed–aquatic/terrestrial or land plants, respectively) and other attributes.

Leak-off test: A type of **injection test** performed by pumping fluid into a well in which a target rock layer is exposed, then monitoring the fluid pressure. The pressure typically rises until it is high enough to force fluids into the rock layer, then it begins to fall. A leak-off test provides information about well integrity, operating pressures, and **fracture gradients**.

Live oil: Oil in which gas is dissolved. When live oil is pumped to the surface, the drop in pressure can release the gas, creating a risk of explosion or fire. Compare to **Dead oil**.

Material Safety Data Sheet: A document containing information on the potential hazards (health, fire, reactivity and environmental) of a material. In Canada, every material that is controlled by the Workplace Hazardous Materials Information System must have an accompanying data sheet.

Measured depth: The length of an actual borehole, regardless of its angle or changes in direction. If the well is vertical, measured depth will be the same as **true vertical depth**. But if the well was drilled at an angle (**directional drilling**) or changed direction to follow a rock formation (**horizontal drilling**), then its measured depth will be significantly greater than true vertical depth.

Millidarcy: One thousandth of a **darcy**, a measure of rock **permeability**.

Neutron porosity log: A type of **wireline log** in which a rock formation is bombarded with high-energy neutrons and their rate of absorption is measured. Hydrogen (abundant in water/pore fluids) most effectively absorbs the neutrons, so the absorption of neutrons can be used to indicate rock porosity.

Naturally occurring radioactive material: Low-level radioactive material that naturally exists in rocks and minerals.

Operator: As defined in the federal drilling regulations (*see* Appendix C, Regulatory Environment), an individual or company that seeks or has been granted approval to conduct a drilling program.

Ophiolites: Displaced or exposed slices of the ocean floor and associated mantle.

Orogeny: An event in which a section of the Earth's crust is folded and thickened by faults to form a mountain range due to the collision of tectonic plates.

Oxygen index: As measured using **Rock Eval** technology, an index that measures the proportions of oxygen and carbon in a rock. Because the proportions vary in different kinds of organic matter (for example, land plants, marine sediments), oxygen index helps to indicate the origin of the hydrocarbon. In combination with the **hydrogen index**, it also indicates **thermal maturity**.

Permeability: A rock's capacity to allow fluid flow, dependent upon the size and shape of pores and other voids and upon how they are interconnected. Permeability may occur naturally or be artificially enhanced by hydraulic fracturing. Compare to **Porosity**.

Petroleum: Oil or gas derived from rock formations below the ground. In this report, used interchangeably with **hydrocarbon**.

Play: In petroleum geology, a set of known or predicted accumulations of oil and or gas defined by common geological characteristics such as similar reservoir rock, source rock, seal rock, and history. One or more plays can occur in a given petroleum system.

Porosity log: A type of **wireline log** that measures the pore volume in a volume of rock using either acoustic or nuclear technology.

Porosity: The ability of a rock to store fluids due to the size and shape of spaces (pores) between mineral grains or the presence of other voids. A rock can be porous without being permeable if pores and voids are isolated and lack interconnection. Compare to **Permeability**.

Produced water: Water naturally present in a hydrocarbon **reservoir,** or injected into the reservoir, that flows from a well along with the gas or oil.

Proppant (propping agent): A non-compressible material, most commonly sand, added to the fracturing fluid and pumped into the open fractures to keep them propped open once the fracturing pressures are removed.

Recycling: In unconventional hydrocarbon operations, the process of treating **flowback water** or **produced water** to allow it to be reused either for hydraulic fracturing or for another purpose.

Reflection seismology: A technique using weak, artificially created seismic waves in tests performed along a series of survey lines. Rocks reflect seismic waves in characteristic ways, and computer programs can use data from the reflections to locate and map rock formations below the Earth's surface.

Reservoir: Any unit of rock having the ability to store petroleum for potential extraction, usually due to its favourable porosity and permeability.

Resistivity log: A type of electric **wireline log** that measures how strongly a rock formation impedes the flow of an electric current. The resistivity of water is low, but for hydrocarbons it is very high, so resistivity can help evaluate hydrocarbon resources.

Rig: *See* **Drill rig**.

Risk: The probability that a hazard or unwanted outcome will occur.

Risk assessment: An evaluation that identifies potential causes of adverse events, plans how to reduce or eliminate their occurrence, and prepares for a quick and effective response if they occur.

Rock Eval: A widely used analytical system for measuring a standard set of hydrocarbon properties, such as hydrocarbon concentrations and **thermal maturity**. A regional collection of data obtained using the Rock Eval system may be gathered into a Rock Eval database.

Saline groundwater: Groundwater that has more than 4000 milligrams per litre total dissolved solids (or as defined by the jurisdiction).

Seal rock: A rock unit with low **permeability** that traps oil or gas beneath it and prevents the hydrocarbon from moving upward to the Earth's surface.

Seep, Show: A **seep** is a film, coating, small pool, or other accumulation of crude oil on the Earth's surface, formed by a natural process. A **show** of oil or gas is any sign or trace of hydrocarbon encountered below the surface, *i.e.*, in a wellbore.

Seismic reflection: *See* **Reflection seismology**.

Seismicity: The frequency and magnitude of earthquake activity in a given area.

Shale gas, Shale oil: For the purposes of this report, unconventional hydrocarbon resources from low-permeability shale formations that typically require **stimulation** (usually by hydraulic fracturing) to release gas or oil from the rock. Also known as **tight gas** and **tight oil**, oil-in-shale or light tight oil.

Slickenside: A thin mineral coating that forms where friction heats a rock surface during movement along a fault. Sometimes the coating includes elongated, fibre-like minerals aligned with the direction of movement.

Slickwater: A water-based fluid containing friction-reducing agents and commonly potassium chloride.

Sonic log: A type of **wireline log** that provides information about the acoustic properties of a rock. These typically vary with rock type and rock texture, but especially with porosity.

Source rock: A unit of rock containing organic matter that can generate hydrocarbons under the correct conditions of heat and pressure.

Spud: In the oil and gas industry, the act of starting to drill a new well.

Stimulation: Artificial enhancement of the permeability of a rock layer around a wellbore to promote the flow of hydrocarbons, using hydraulic fracturing or other techniques.

Stratigraphy: The study of rock layers, their distribution, and the sequence in which they formed; or, the properties of a specific sequence of rock layers, for example, in a specific region.

Strike: For a tilted rock layer, fault, or other non-horizontal rock feature, the compass direction of a line representing the intersection of the feature with a horizontal plane. Together with **dip**, it describes the orientation of the feature.

Succession: A series of related rock layers, often having formed under fluctuating but broadly similar conditions during a specified period of time.

Surface water: Water collecting on the ground or in a stream, river, lake, sea, or ocean. Compare to **Groundwater**.

Target formation: A rock layer or series of layers predicted or known to contain valuable resources and focussed upon as the object of study, testing, development, or other activity.

Tectonic plates: Large segments into which the Earth's lithosphere (outer layer) is divided along boundaries defined by specific kinds of volcanic activity and **seismicity**, for example, along mid-ocean ridges, ocean trenches, and certain large faults. Some tectonic plates include regions of both oceanic and continental crust.

Thermal maturity: The extent to which a hydrocarbon resource or its source rock has been heated during its geological history. Progressive heating transforms an original biomass into coal, oil, or gas, so thermal maturity helps predict the type of resource likely to be present in a reservoir.

Thermogenic: Formed by the combined forces of high pressure and temperature due to deep burial within the Earth's crust.

Tight gas, Tight oil: A hydrocarbon resource that is trapped in rock layers of low permeability; sometimes specifically referring to low-permeability sandstone or limestone as opposed to shale. Also *see* **Shale gas, Shale oil**.

Tmax: As measured using **Rock Eval** technology, the temperature at which the maximum amount of hydrocarbon is released (S2 peak). Tmax can vary with the thermal history of the rock sample and so predicts the amount of oil and gas that can be generated at the current **thermal maturity** of the sample.

Total dissolved solids: The dry weight of material – organic and inorganic – dissolved in water and usually expressed in parts per million (ppm).

Trade secret: Any process, equipment, knowledge, or substance that provides a business advantage over competitors who do not have access to it and that is allowed to remain undisclosed under applicable laws.

True vertical depth: The vertical distance between the surface (typically sea level) and the end of a borehole. If the well is vertical, **measured depth** will be the same as true vertical depth. If the well was drilled at an angle (**directional drilling**) or changed direction to follow a rock formation (**horizontal drilling**), then its true vertical depth will be significantly less than measured depth.

Unconformity: An interruption or gap in an otherwise continuous record of sedimentary rock formation, usually involving the uplift, exposure, and erosion of existing rock layers prior to the deposition of new sediments onto them.

Unconventional hydrocarbon: A **play** where the source, reservoir, and seal rock are the same unit because hydrocarbon has been generated in a highly impermeable rock unit and remains trapped there. Typically, **stimulation** technologies such as hydraulic fracturing are required to liberate such a resource. Examples include the Barnett shale of Texas and the Marcellus shale of Pennsylvania.

Vertical derivative: In aeromagnetic surveys, a factor used in data processing that takes account of the vertical rate of change in the magnetic field. Using the first vertical derivative highlights variations closer to the surface, while using the second vertical derivative highlights boundaries between zones of interest.

Vitrinite: One of the primary components of coal and most sedimentary **kerogens,** derived from the cell-wall material or woody tissue of plants and peat.

Vitrinite reflectance: The percentage of light reflected from sample grains of vitrinite, often measured with the grains immersed in oil and reported as Ro%, typically in the range 0–3%. Higher values indicate greater thermal maturity.

Waste water: Spent or used water containing dissolved or suspended solids or mixed with other liquids. In hydraulic fracturing operations, **produced water** and **flowback water** are forms of waste water.

Water well: A well with the primary purpose of providing non-saline **groundwater**.

Well completion: *See* Completion.

Well control event: The unintended flow of fluid from the wellbore, either at depth between rock formations, or to the surface either as a controllable flow or as a blowout.

Well integrity: The ability of a well to prevent the unintended escape of fluids (liquids or gases) into rock formations or to the surface. Well integrity relies on the quality of materials and processes used in well construction, testing, and operation.

Well log: A continuous record of rock properties throughout the length of a well. To create a log, rock samples or drilling mud can be brought to the surface and inspected or tested; or instruments can be lowered into the well to measure a wide variety of characteristics along the walls of the borehole.

Wellbore: For the purposes of this report, the open hole that is drilled prior to the installation of casing and cement and equivalent to a borehole.

Wireline log: A continuous record of rock properties made using a cable to lower instruments into the well. Depending on the equipment used, the data may be gathered for later retrieval or transmitted to the surface for immediate inspection. Logs can be made at various stages in well development and operations, some after the casings are in place.

E. ABBREVIATIONS

This report avoids the use of acronyms or abbreviations, but some commonly used ones are defined here for the convenience of readers who may encounter them in the works listed in Appendix F, or elsewhere.

ALARP	as low as reasonably practicable
API	American Petroleum Institute
bbl/min, bbl/day	barrels per minute, barrels per day
bcfg	billion cubic feet gas
BGWP	base of groundwater protection
BOE	barrels of oil equivalent
BOPD	barrels of oil per day
BTU	British Thermal Unit
CAI	Conodont Alteration Index
CAPP	Canadian Association of Petroleum Producers
CBM	coal-bed methane
CNLOPB	Canada–Newfoundland and Labrador Offshore Petroleum Board
DST	drillstem test
EL	exploration license
EPA	U.S. Environmental Protection Agency
EUR	estimated ultimate reserves
FIT	formation integrity test
GHG	greenhouse gas
GIP	gas in place
GOR	gas/oil ratio
GSNL	Geological Survey Newfoundland and Labrador
GSC	Geological Survey of Canada
HC	hydrocarbons
HI	hydrogen index (Rock Eval)
IP	initial potential
LOT	leak-off test
LTO	light, tight oil
Ma	millions of years
Mcfg	thousand cubic feet of gas
Mcfge	thousand cubic feet of gas equivalent

md	millidarcies
MD	measured depth
mg/L	milligrams per litre
MMcfg	million cubic feet of gas
MMcfge	million cubic feet of gas equivalent
MSDS	Material Safety Data Sheet
NGL	natural gas liquids
NORM	naturally occurring radioactive materials
OGDP	Offshore Geoscience Data Program
OI	oxygen index (Rock Eval)
PEEP	Petroleum Exploration and Enhancement Program
ppt, ppm	parts per thousand, parts per million
RHOB	bulk density (the Greek letter Rho “ϱ” is the symbol used for density)
Ro	vitrinite reflectance value (in %)
S1	thermally extractable petroleum (Rock Eval)
S2	petroleum potential, a peak generated by pyrolysis (Rock Eval)
scfg/t	standard cubic feet of gas per ton of rock
TAI	thermal alteration index
tcfg	trillion cubic feet gas
TD	total depth
TDS	total dissolved solids
TENORM	technically enhanced naturally occurring radioactive materials
TFHL	theoretical fracture half-length
Tmax	temperature of maximum S2 release (Rock Eval)
TOC	total organic carbon
TVD	true vertical depth
USGS	U.S. Geological Survey
VR	vitrinite reflectance

F. FURTHER RESOURCES

This section includes all articles cited in the report as well as sources of additional information.

Albani, R., Bagnoli, G., Maletz, J. and Stouge, S.
2001: Integrated chitinozoan, conodont, and graptolite biostratigraphy from the upper part of the Cape Cormorant Formation (Middle Ordovician), western Newfoundland. Canadian Journal of Earth Sciences, v. 38, p. 387-409.

AMEC Earth and Environmental
2008: Hydrogeology of western Newfoundland [Report]. Water Resources Management Division, NL Department of Environment and Conservation, 70 pp. http://www.env.gov.nl.ca/env/waterres/reports/hydrogeology_westernnl/final_report.pdf

Arthur, J.D., Bohm, B., Coughlin, B.J. and Layne, M.
2008: Hydraulic fracturing considerations for natural gas wells of the Fayetteville Shale [Report]. Tulsa, OK, ALL Consulting, 19 pp. http://www.all-llc.com/publicdownloads/ALLFayettevilleFracFINAL.pdf

BC Oil and Gas Commission
2012: Investigation of observed seismicity in the Horn River Basin. http://www.bcogc.ca/node/8046/download?documentID=1270&type=.pdf

Bertrand, R.
1991: Maturation thermique des roches mères dans les bassins des basses-terres du Saint-Laurent et dans quelques buttes témoins au sud-est du Bouclier canadien. International Journal of Coal Geology, v. 19, p. 359-383.

Bertrand, R., Lavoie, D. and Fowler, M.
2003: Cambrian-Ordovician shales in the Humber Zone: Thermal maturation and source rock potential. Bulletin of Canadian Petroleum Geology, v. 51, p. 213-233.

Bostock, H.H., Cumming, L.M., Williams, H. and Smith, W.R.
1983: Geology of the Strait of Belle Isle area, northwestern insular Newfoundland, southern Labrador and adjacent Quebec. Geological Survey of Canada, Memoir 400, 145 pp.

Botsford, J.
1988: Geochemistry and petrology of lower Paleozoic platform-equivalent shales, western Newfoundland. Newfoundland Department of Mines and Energy, Mineral Development Division, Report 88-1, p. 85-98.

Bowker, K.A.
2003: Recent developments of the Barnett shale play, Fort Worth Basin. West Texas Geological Society Bulletin, v. 42, p. 8-10.

Bowker, K.A.
2007: Barnett shale gas production, Fort Worth Basin: Issues and discussion. American Association Petroleum Geologists Bulletin, v. 91, p. 523-533.

Bruner, K.R. and Smosma, R.
2011: A comparative study of the Mississippian Barnett Shale, Fort Worth Basin, and Devonian Marcellus shale, Appalachian Basin [Report]. U.S. Department of Energy, DOE/NETL-2011/1478, 118 pp. http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/DOE-NETL-2011-1478%20Marcellus-Barnett.pdf

Canadian Association of Petroleum Producers (CAPP)
2012: Industry establishes Canada-wide operating practices for shale, tight natural gas hydraulic fracturing [Media release], January 30, 2012. http://www.capp.ca/aboutUs/mediaCentre/NewsReleases/Pages/operating-practices-for-hydraulic-fracturing.aspx

Canadian Association of Petroleum Producers (CAPP)
2013: CAPP's Guiding Principles and Operating Practices for Hydraulic Fracturing. http://capp.ca/canadaIndustry/naturalGas/ShaleGas/Pages/default.aspx
Canadian Nuclear Safety Commission
2009: How is radioactive waste classified? [Webpage]. http://nuclearsafety.gc.ca/eng/about/regulated/radioactivewaste/how.cfm
Canadian Society for Unconventional Gas (CSUG)
2013: Understanding hydraulic fracturing [Brochure]. Calgary, AB, 24 pp. http://www.csur.com/images/CSUG_publications/CSUG_HydraulicFrac_Brochure.pdfhttp://www.csur.com/images/CSUG_publications/CSUG_HydraulicFrac_Brochure.pdf
Cardno Entrix
2012: Hydraulic fracturing study, PXP Inglewood oil field, October 10, 2012 [Report]. Los Angeles, CA, 206 pp. http://www.eenews.net/assets/2012/10/11/document_ew_01.pdf
Cathles, L.M. III, Brown, L., Taam, M. and Hunter, A.
2011: A commentary on "The greenhouse-gas footprint of natural gas in shale formations" by R.W. Howarth, R. Santoro and A. Ingraffea. Climatic Change, v. 113, p. 525-535. doi:10.1007/s10584-011-0333-0
Cawood, P.A., McCausland, P.J.A. and Dunning, G.R.
2001: Opening Iapetus: Constraints from the Laurentian margin in Newfoundland. Geological Society of America Bulletin, v. 113, p. 443-453.
Chaudhry, J., Rae, D. and Clark, E.
2001: Basin evolution in western Newfoundland: New insights from hydrocarbon exploration. AAPG Bulletin, v. 85(3), p. 393-418.
CNLOPB
2010: Seismic data coverage: Offshore Newfoundland and Labrador [Report]. St. John's, NL. ISBN 978-1-897101-97-1. http://www.cnlopb.nl.ca/pdfs/seisdatacoverage.pdf
CNLOPB
(n.d.): Core storage and research centre [Webpage]. St. John's, NL, http://www.cnlopb.nl.ca/loc_csrc.shtml
Colmann-Sadd, S.P. and Scott, S.A.
1994: Newfoundland and Labrador: Traveller's guide to the geology and guidebook to stops of interest [Map and booklet]. St. John's, NL: Canada–Newfoundland Cooperation on Mineral Development, 91 pp.
Coniglio, M. and James, N.P.
1990: Origin of fine-grained carbonate and siliciclastic sediments in an Early Paleozoic slope sequence, Cow Head Group, western Newfoundland. Sedimentology, v. 37, p. 215-230.
Cooper, M., Weissenberger, J., Knight, I., Hostad, D., Gillespie, D., Williams, H., Burden, E., Porter-Davies, R.J., Mathias, S.A., Moss, J., Hustoft, S. and Newport, L.
2012: Hydraulic fractures: How far can they go? Marine and Petroleum Geology, v. 37, p. 1-6. doi:10.1016/j.marpetgeo.2012.04.001
de Pater, C.J. and Baisch, S.
2011: Geomechanical study of Bowland Shale seismicity: Synthesis report. Staffordshire, U.K., Cuadrilla Resources Ltd., 71 pp. http://www.cuadrillaresources.com/wp-content/uploads/2012/02/Geomechanical-Study-of-Bowland-Shale-Seismicity_02-11-11.pdf
Ellsworth, W.L., Hickman, S.H., Lleons, A.L., Mcgarr, A., Michael, A.J., Rubinstein, J.L.
2012: Are seismicity rate changes in midcontinent natural or manmade? [Abstract]. Seismological Society of America Annual Meeting, 17-19 April, San Diego, CA. http://www.seismosoc.org/meetings/2012
Enachescu, M.E.
2006: Call for Bids NL06-3, Parcels 1 to 5, Regional Setting and Petroleum Geology Evaluation. Newfoundland and Labrador Department of Natural Resources, 55 pp.

Ferrill, D.A., Winterle, J., Wittmeyer, G., Sims, D., Colton, S., Armstrong, A. and Morris, A.P.
1999: Stressed rock drains groundwater at Yucca Mountain, Nevada. GSA Today, v. 9, p. 1-8. http://www.geosociety.org/gsatoday/archive/9/5/pdf/i1052-5173-9-5-1.pdf

Fleming, J.M.
1970: Petroleum exploration in Newfoundland and Labrador. Newfoundland Department of Mines, Agriculture and Resources, Mineral Resources Report, No. 3. 118 pp.

Fowler, M.G., Hamblin, A.P., Hawkins, D., Stasiuk, L.D. and Knight, I.
1995: Petroleum geochemistry and hydrocarbon potential of Cambrian and Ordovician rocks of western Newfoundland. Bulletin of Canadian Petroleum Geology, v. 43(2), p. 187-213.

Frohlich, C., Potter, E., Hayward, C. and Stump, B.
2010: Dallas-Ft. Worth earthquakes coincident with activity associated with natural gas production. The Leading Edge, March 2010, p. 270-275. http://smu.edu/newsinfo/pdf-files/earthquake-study-10march 2010.pdf

Geny, F.
2010: Can unconventional gas be a game changer in European gas markets? [Report]. Oxford Institute for Energy Studies, Oxford, U.K., 127 pp. http://www.oxfordenergy.org/2010/12/can-unconventional-gas-be-a-game-changer-in-european-gas-markets

Givens, N. and Zhao, H.
2009: The Barnett Shale: Not so simple after all [Report]. Bureau of Economic Geology, University of Texas, Austin, Texas, 14 pp. http://www.beg.utexas.edu/pttc/archive/barnettshalesym/notsosimple.pdf

Gottschling, J.
2007: Appalachian Basin black shale exploitation: Past, present, and future [Presentation]. Pennsylvania Independent Oil and Gas Association Annual Meeting, May 16-17, Pittsburgh, PA, 49 pp.

Hamblin, A.P.
2006: The "shale gas" concept in Canada: A preliminary inventory of possibilities. Geological Survey of Canada, Open File Report 5384, 108 pp. http://geogratis.gc.ca/api/en/nrcan-rncan/ess-sst/2246f370-67f8-5e43-8168-d2a8cd57e936.html

Hamblin, A.P., Fowler, M.G., Utting, J., Hawkins, D. and Riediger, C.L.
1995: Sedimentology, palynology and source rock potential of Lower Carboniferous (Tournaisian) rocks, Conche area, Great Northern Peninsula, Newfoundland. Bulletin of Canadian Petroleum Geology, v. 43, p. 1-19.

Healy, D.
2012: Hydraulic fracturing or 'fracking': A short summary of current knowledge and potential environmental impacts [Report]. Environmental Protection Agency, Wexford, Ireland. http://www.epa.ie pubs/reports/research/sss/epa-strivesmallscalestudyreport.html

Hicks, L.G.
2005: First international symposium on oil and gas resources in western Newfoundland [Excursion guidebook]. Government of Newfoundland and Labrador, Department of Natural Resources, 43 pp.

Hicks, L., Waldron, J. and Burden, E.
2010: An under-explored western Newfoundland slope/rise turbidite petroleum system awaits discovery [Field trip guidebook]. Western Newfoundland Oil and Gas Symposium, September 23-24, Marble Mountain, NL, 70 pp.

Howarth, R.W., Santoro, R. and Ingraffea, A.
2011: Methane and the greenhouse-gas footprint of natural gas from shale formations. Climatic Change, v. 106, p. 679-690. doi:10.1007/s10584-011-0061-5

Hyde, R.S.
1995: Upper Paleozoic rocks, Newfoundland. *In* Geology of the Appalachian-Caledonian Orogen in Canada and Greenland, Chapter 5. *Edited by*: H. Williams. Geology of Canada, No. 6, p. 523-552.

James, N.P., Barnes, C.R., Boyce, W.D., Cawood, P.A., Knight, I., Stenzel, S.R., Stevens, R.K. and Williams, S.H.
1988: Carbonates and faunas of western Newfoundland [Field trip guidebook]. Fifth International Symposium on the Ordovician System, St. John's, Newfoundland, 123 p.

James, N.P., Barnes, C.R., Stevens, R.K. and Knight, I.
1989: A Lower Paleozoic continental margin carbonate platform, northern Canadian Appalachians. *In* Controls on Carbonate Platforms and Basin Development. *Edited by*: T. Crevello, R. Sarg, J.F. Read and J.L. Wilson. Society of Economic Paleontologists and Mineralogists, Special Publication 44, p. 123-146.

James, N.P. and Stevens, R.K.
1986: Stratigraphy and correlation of the Cambro-Ordovician Cow Head Group, western Newfoundland [Report]. Geological Survey of Canada, Bulletin 366, 143 pp.

Jarvie, D.M., Hill, R.J., Ruble, T.E. and Pollastro, R.M.
2007: Unconventional shale-gas systems: The Mississippian Barnett shale of north-central Texas as one model for thermogenic shale-gas assessment. AAPG Bulletin, v. 91, p. 475-499.

Johnston, D.
2004: Barnett Shale-1: Technological advances expand potential play. Oil and Gas Journal, v. 102(3), p. 51-59.

Kean, B.F.
2010: Bonavista Peninsula and the Discovery Trail: A journey through geological, historical and modern time. [Unpublished report] 241 pp.

King, G.E.
2010: Thirty years of gas shale fracturing: What have we learned? Paper SPE 133456, presented at the Society of Petroleum Engineers Annual Technical Meeting and Exhibition, 19-22 September, Florence, Italy. doi:10.2118/133456-MS

King, G.E.
2012: Hydraulic fracturing 101: What every representative, environmentalist, regulator, reporter, investor, university researcher, neighbor and engineer should know. Society of Petroleum Engineers Hydraulic Fracturing Technology Conference, 6-8 February, The Woodlands, TX. doi:10.2118/152596-MS

Knight, I.
1983: Geology of the Carboniferous Bay St. George subbasin, western Newfoundland. Newfoundland Department of Mines and Energy, Mineral Development Division, Memoir 1, 358 pp. http://www.nr.gov.nl.ca/nr/mines/geoscience/publications/docs.html

Knight, I.
1994: Geology of Cambrian-Ordovician platformal rocks of the Pasadena map sheet (12H/4). *In* Current Research. Newfoundland and Labrador Department of Natural Resources, Geological Survey, Report 94-1, p. 175-186. http://www.nr.gov.nl.ca/nr/mines/geoscience/publications/currentresearch/1994/ knight _pasadena.pdf

Knight, I.
1995: Preliminary 1:50 000 mapping of lower Paleozoic parautochthonous sedimentary rocks of the Corner Brook area. *In* Current Research. Newfoundland and Labrador Department of Natural Resources, Geological Survey, Report 95-1, p. 257-265. http://www.nr.gov.nl.ca/nr/mines/geoscience/publications/currentresearch/1995/knight.pdf

Knight, I.
1997: Geology of Cambro-Ordovician carbonate shelf and coeval off-shelf rocks, southwest of Corner Brook, western Newfoundland. *In* Current Research. Newfoundland and Labrador Department of Natural Resources, Geological Survey, Report 97-1, p. 211-235. http://www.nr.gov.nl.ca/nr/mines/geoscience/publications/currentresearch/1997/knight.pdf

Knight, I.
2013: The Forteau Formation, Labrador Group, in Gros Morne National Park: A preliminary reassessment of its stratigraphy and lithofacies. *In* Current Research. Newfoundland and Labrador Department of Natural Resources, Geological Survey, Report 13-1, p. 267-300. http://www.nr.gov.nl.ca/nr/mines/geoscience/publications/currentresearch/2013/Knight_2013.pdf

Knight, I., Azmy, K., Greene, M.G. and Lavoie, D.
2007: Lithostratigraphic setting of diagenetic, isotopic, and geochemistry studies of Ibexian and Whiterockian carbonate rocks of the St. George and Table Head groups, western Newfoundland. *In* Current Research. Newfoundland and Labrador Department of Natural Resources, Geological Survey, Report 07-1, p. 55-84. http://www.nr.gov.nl.ca/nr/mines/geoscience/publications/currentresearch/2007/knight.pdf

Knight, I. and Boyce, W.D.
1991: Deformed Lower Paleozoic platform carbonates, Goose Arm-Old Man's Pond. *In* Current Research. Newfoundland and Labrador Department of Natural Resources, Geological Survey, Report 91-1, p. 141-153. http://www.nr.gov.nl.ca/nr/mines/geoscience/publications/currentresearch/1991/knight.pdf

Knight, I. and James, N.P.
1987: The stratigraphy of the Lower Ordovician St. George Group, western Newfoundland: The interaction between eustasy and tectonics. Canadian Journal of Earth Sciences, v. 24, p. 1927-1951.

Knight, I. and James, N.P.
1988: Stratigraphy of the Lower to Lower Middle Ordovician St. George Group, western Newfoundland. Newfoundland Department of Mines, Geological Survey, Report 88-4, 48 pp.

Knight, I., James, N.P. and Lane, T.E.
1991: The Ordovician St. George Unconformity, northern Appalachians: The relationship of plate convergence at the St. Lawrence Promontory to the Sauk/Tippecanoe sequence boundary. Geological Society of America Bulletin, v. 103, p. 1200-1225.

Macauley, G.
1987: Organic geochemistry of some Cambro-Ordovician outcrop samples, western Newfoundland. Geological Survey of Canada, Open File OF1503, 15 pp.

Majer, E.L., Baria, R., Stark, M., Oates, S., Bommer, J., Smith, B. and Asanuma, H.
2007: Induced seismicity associated with Enhanced Geothermal Systems. Geothermics, v. 36(3), p. 185-222. doi:10.1016/j.geothermics.2007.03.003

Massachusets Institute of Technology (MIT)
2011: The future of natural gas: An interdisciplinary MIT study. [Report] Cambridge, MA, 178 pp. http://mitei.mit.edu/system/files/NaturalGas_Report.pdf

McKillop, J.H.
1957: Gas and petroleum occurrence at Flat Bay, St. George's, Newfoundland. [Unpublished Report] Geological Survey of Newfoundland, St. John's, NL.

Moore, S.
2012: Gas works? Shale gas and its policy implications. [Report]. Policy Exchange, London, U.K.,. 77 pp. http://www.policyexchange.org.uk/images/publications/gas%20works%20-%20feb%2012.pdf

Morris, A., Ferrill D.A. and Henderson, D.B.
1996. Slip-tendency analysis and fault reactivation. Geology, v. 24, p. 275-278.

National Research Council
2012: Induced seismicity potential in energy technologies: A report of the National Research Council [Advance copy]. National Research Council of the National Academies, Washington, DC, 240 pp. http://i2.cdn.turner.com/cnn/2012/images/06/15/induced.seismicity.prepublication.pdf

Newfoundland and Labrador Department of Energy
1989: Hydrocarbon potential of the western Newfoundland onshore area. Newfoundland Department of Mines and Energy, 20 pp. http://www.nr.gov.nl.ca/mines&en/publications/onshore/hydrocarbon.pdf

Newfoundland and Labrador Department of Environment and Conservation
2012: Drinking water safety in Newfoundland and Labrador: Annual report 2012. Water Resources Management Division, St. John's, NL, 41 pp. http://www.env.gov.nl.ca/env/waterres/reports/index.html#1
Newfoundland and Labrador Department of Environment and Conservation
2013a: Environment and conservation. [Webpage] http://www.env.gov.nl.ca/env/index.html
Newfoundland and Labrador Department of Environment and Conservation
2013b: Data and tools. [Webpage] Water Resources Management Division, St. John's, NL. http://www.env.gov.nl.ca/env/waterres/datatools/index.html
Newfoundland and Labrador Department of Environment and Conservation
[n.d.]: Water Resources Management Division. [Brochure] Water Resources Management Division, St. John's, NL, 4 pp. http://www.env.gov.nl.ca/env/waterres/divisional_brochure.pdf
Newfoundland and Labrador Department of Mines and Energy
2000: Sedimentary basins and hydrocarbon potential of Newfoundland and Labrador. Energy Branch, Report 2000-01, 71 pp. http://www.nr.gov.nl.ca/nr/publications/energy/sedimentarybasins.pdf
Newfoundland and Labrador Department of Natural Resources
2008: Oil and gas report (Feb. 2008). St. John's, NL, 40 pp. http://www.nr.gov.nl.ca/nr/publications/energy/oilgasreport08.pdf
Newfoundland and Labrador Petroleum Directorate
1981: The petroleum potential of the western Newfoundland onshore area. Resource Assessment Division, Special Report, PD 81-2, 34 pp.
Newfoundland and Labrador Petroleum Directorate
1982: Onshore/offshore western Newfoundland, prospects for petroleum. Resource Assessment Division, Special Report, PD 82-1, 85 pp. http://www.nr.gov.nl.ca/nr/publications/energy/onoffshore.pdf
Nicholson, C. and R.L. Wesson
1990: Earthquake hazard associated with deep well injection: A report to the U.S. Environmental Protection Agency. U.S. Geological Survey Bulletin 1951, 74 pp.
Nolen-Hoeksema, R.
2013: Elements of hydraulic fracturing. Schlumberger Oilfield Review, Summer 2013, p. 51-52. http://www.slb.com/resources/publications/oilfield_review/en.aspx
Nowlan, G.S. and Barnes, C.R.
1987: Thermal maturation of Paleozoic strata in eastern Canada from conodont colour alteration index (CAI) data with implications for burial history, tectonic evolution, hotspot tracks and mineral and hydrocarbon exploration. Geological Survey of Canada, Bulletin 367, 47 pp.
Osborn, S.G., Vengosh, A., Warner, N.R. and Jackson, R.B.
2011: Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. Proceedings of the National Academy of Sciences of the United States of America, v. 108(20), p. 8172-8176.
Petroleum Services Association of Canada
(n.d.): Working energy commitment: Hydraulic fracturing code of conduct. [Brochure] 2 pp. http://www.oilandgasinfo.ca/working-energy-commitment/hydraulic-fracturing-code-of-conduct
Pollastro, R.M.
2007: Total petroleum system assessment of undiscovered resources in the giant Barnett shale continuous (unconventional) gas accumulation, Fort Worth Basin, Texas. AAPG Bulletin, v. 1(4), p. 551-578. doi:10.1306/06200606007
Rowe, C.
2003: Novel 3D transition zone seismic survey, Shoal Point, Port au Port Peninsula, Newfoundland: Seismic data processing and interpretation [Unpublished M.Sc. thesis]. Memorial University, St. John's, NL, 310 pp.

Royal Society and Royal Academy of Engineering
2012: Shale gas extraction in the UK: A review of hydraulic fracturing. [Report] London, U.K., 76 pp. http://royalsociety.org/uploadedFiles/Royal_Society_Content/policy/projects/shale-gas/2012-06-28-Shale-gas.pdf

Schlumberger Ltd.
(n.d.): The oilfield glossary [Website]. http://www.glossary.oilfield.slb.com

Secretary of Energy Advisory Board (SEAB)
2011a: The SEAB Shale Gas Production Subcommittee Ninety-Day Report—August 11, 2011. U.S. Department of Energy, Washington, DC, 41 pp. www.shalegas.energy.gov/resources/081111_90_day_report.pdf

Secretary of Energy Advisory Board (SEAB)
2011b: The SEAB Shale Gas Production Subcommittee Second Ninety-Day Report—November 18, 2011. U.S. Department of Energy, Washington, D.C., 23 pp. www.shalegas.energy.gov/resources/111011_90_day_report.pdf

Shaw, J., Batterson, M., Christian, H. and Courtney, R.C.
2000: A multibeam bathymetric survey of Bay of Islands, Newfoundland: New evidence of late-glacial and Holocene geological processes. Atlantic Geology, v. 36, p. 139-155.

Sinclair, I.K.
1990: A review of the Upper Precambrian and Lower Paleozoic geology of western Newfoundland and the hydrocarbon potential of the adjacent offshore area in the Gulf of St. Lawrence. Canada–Newfoundland Offshore Petroleum Board, GL-CNLOPB-90-01, 79 pp.

Stenzel, S.R., Knight, I. and James, N.P.
1990: Carbonate platform to foreland basin: Revised stratigraphy of the Table Head Group (Middle Ordovician), western Newfoundland. Canadian Journal of Earth Sciences, v. 27, p. 14-26.

Stockmal, G.S., Slingsby, A. and Waldron, J.W.F.
1998: Deformation styles at the Appalachian structural front, western Newfoundland: Implications of new industry seismic reflection data. Canadian Journal of Earth Sciences, v. 35, p. 1288-1306.

Stockmal, G.S., Slingsby, A. and Waldron, J.W.F.
2004: Basement-involved inversion at the Appalachian structural front, western Newfoundland: An interpretation of seismic reflection data with implications for petroleum prospectivity. Bulletin of Canadian Petroleum Geology, v. 52(3), p. 215-233.

Stockmal, G.S. and Waldron, J.W.F.
1990: Structure of the Appalachian deformation front in western Newfoundland: Implications of multichannel seismic reflection data. Geology, v. 18, p. 765-768.

Stockmal, G.S., Waldron, J.W.F. and Quinlan, G.M.
1995: Flexural modeling of Paleozoic foreland basin subsidence, offshore western Newfoundland: Evidence for substantial post-Taconian thrust transport. Journal of Geology, v. 103, p. 653-671.

Stouge, S.
1986: Conodont colour variation in the lower/middle Ordovician strata of western Newfoundland. *In* Current Research. Newfoundland and Labrador Department of Natural Resources, Geological Survey, Report 86-1, p. 177-178. http://www.nr.gov.nl.ca/nr/mines/geoscience/publications/research.html

Sumi, L.
2008: Shale gas: Focus on the Marcellus shale. [Report] Oil and Gas Accountability Project (Earthworks), Durango, CO, 25 pp. http://www.earthworksaction.org/library/detail/marcellus_shale_formation_report_08

U.K. Department of Energy and Climate Change
2012: About shale gas and hydraulic fracturing (fracking). [Report]. London, U.K., 36 pp. http://www.decc.gov.uk/en/content/cms/meeting_energy/oil_gas/shale_gas/shale_gas.aspx

Ullyott, K.W. and Rae, D.R.
1997: MOBIL York Harbour–Lark Harbour–Little Port Water Wells 1, 2 & 3—Final Report.[Release date Jan. 1, 2002] Mobil Oil Canada Properties, 96 pp. www.nr.gov.nl.ca/nr/publications/energy/mobil_report.pdf

U.S. Department of Energy
2009: Modern shale gas development in the United States: A primer. National Energy Technology Laboratory, Strategic Center for Natural Gas and Oil, 116 pp. http://www.netl.doe.gov/technologies/oil-gas/publications/EPreports/Shale_Gas_Primer_2009.pdf

U.S. Department of Energy
2013a: Modern shale gas development in the United States: An update. National Energy Technology Laboratory, Strategic Center for Natural Gas and Oil, 79 pp. http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/shale-gas-primer-update-2013.pdf

U.S. Department of Energy
2013b: NETL statement on reported fracking study. [Media release] http://www.netl.doe.gov/publications/press/2013/StudyStatement.pdf

U.S. Energy Information Administration
2011: Shale gas and oil plays, North America. [Map, updated 5/9/2011] Washington, D.C., Author. http://www.eia.gov/pub/oil_gas/natural_gas/analysis_publications/maps/maps.htm

U.S. Environmental Protection Agency
2010: Hydraulic fracturing research study. [Fact sheet] U.S. EPA Office of Research and Development, Washington, D.C., 2 pp. http://www.epa.gov/safewater/uic/pdfs/hfresearchstudyfs.pdf

U.S. Environmental Protection Agency
2013a: Regulation of hydraulic fracturing under the Safe Drinking Water Act. [Webpage] http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/wells_hydroreg.cfm

U.S. Environmental Protection Agency (USEPA)
2013b: EPA's study of hydraulic fracturing and its potential impact on drinking water resources. [Website] http://www2.epa.gov/hfstudy

Van de Poll, H.W., Gibling, M.R. and Hyde, R.S.
1995: Upper Paleozoic rocks. *In* Geology of the Appalachian-Caledonian Orogen in Canada and Greenland. *Edited by* H. Williams. Chapter 5. Geological Survey of Canada, Geology of Canada Series no. 6, p. 449-566. http://geoscan.nrcan.gc.ca/starweb/geoscan/servlet.starweb?path=geoscan/fulle.web&search1=R=205242

Waldron, J.W.F., DeWolfe, J., Courtney, R. and Fox, D.
2002. Origin of the Odd-Twins anomaly: Magnetic effect of a unique stratigraphic marker in the Appalachian foreland basin, Gulf of St. Lawrence. Canadian Journal of Earth Sciences, v. 39, p. 1675-1687.

Waldron, J.W.F., Hicks, L. and White, S.E.
2012: Stratigraphy, tectonics and petroleum potential of the deformed Laurentian margin and foreland basins in western Newfoundland. [Field trip guidebook 3B] Geological Association of Canada–Mineralogical Association of Canada, Joint Annual Meeting, 28-30 May, St. John's, NL, 155 pp.

Waldron, J.W.F. and Palmer, S.E.
2000: Lithostratigraphy and structure of the Humber Arm Allochthon in the type area, Bay of Islands, Newfoundland. *In* Current Research. Newfoundland and Labrador Department of Natural Resources, Geological Survey, Report 2000-1, p. 279-290. http://www.nr.gov.nl.ca/nr/mines/geoscience/publications/research.html

Waldron, J.W.F., Scott, D.A., Cawood, P. A., Goodwin, L.B., Hall, J., Jamieson, R.A., Palmer, S.E., Stockmal, G.S. and Williams, P.F.
1998: Evolution of the Appalachian Laurentian margin: Lithoprobe results in western Newfoundland. Canadian Journal of Earth Sciences, v. 35, p. 1271-1287.

Waldron, J.W.F. and Stockmal, G.S.
1991: Mid-Paleozoic thrusting at the Appalachian deformation front: Port au Port Peninsula, western Newfoundland. Canadian Journal of Earth Sciences, v. 28, p. 1992-2002.
Warpinski, N.R.
1985: Measurement of width and pressure in a propagating hydraulic fracture. Society of Petroleum Engineers Journal, v. 25(1), p. 46-54. doi:10.2118/11648-PA
Weaver, E.J.
1988: Source rock studies of natural seep oils near Parson's Pond on the west coast of Newfoundland [Unpublished M.Sc. thesis]. Memorial University, St. John's, NL, 178 pp.
Weaver, F.J. and Macko, S.A.
1988: Source rocks of western Newfoundland. Organic Geochemistry, v. 13, p. 411-421.
Williams, S.H. and Burden, E.T.
1992: Thermal maturity of potential Paleozoic source rocks in western Newfoundland: A report to Mobil Canada. [Released 1997] 34 pp. http://www.nr.gov.nl.ca/nr/publications/energy/report4.pdf
Williams, S.H., Burden, E.T. and Mukhopadhyay, P.K.
1998: Thermal maturity and burial history of Paleozoic rocks in western Newfoundland. Canadian Journal of Earth Sciences, v. 35, p. 1307-1322.
Zoback, M.D.
2012: Managing the seismic risk posed by wastewater disposal. Earth, v. 57(4), p. 38-43. http://www.earthmagazine.org/article/managing-seismic-risk-posed-wastewater-disposal