2014

Newfoundland Labrador

Petroleum Development - Activity Report

2014

Department of Natural Resources
Petroleum Development
Activity Report - 2014

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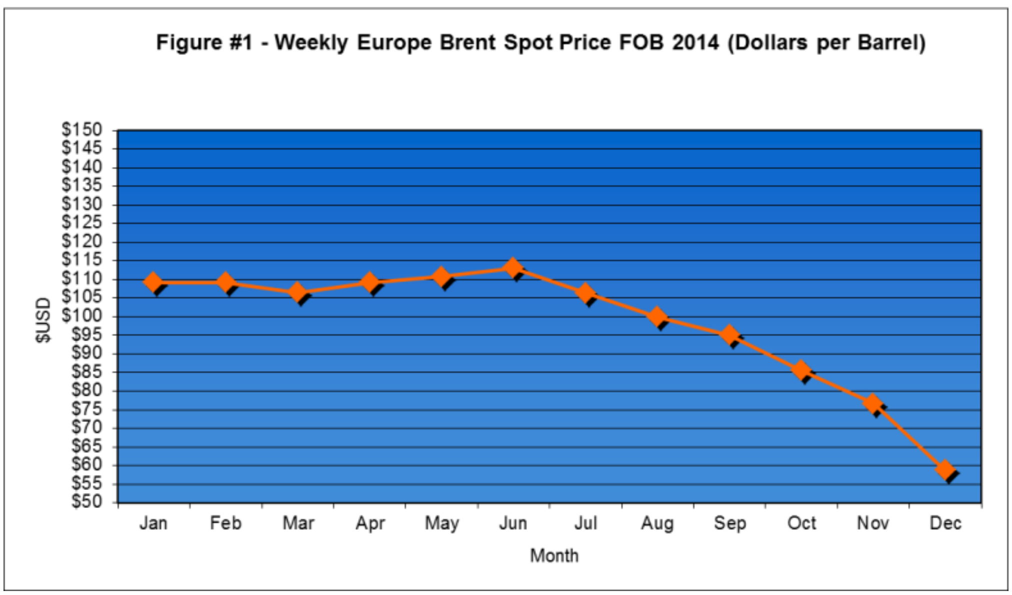
1.0 Introduction

The Province of Newfoundland and Labrador, located on the east coast of North America, has been Canada's offshore oil producing region for the past 18 years. The province's four producing fields, Hibernia, Terra Nova, White Rose and North Amethyst produced 78.9 million barrels of oil in 2014. This was down slightly from 83.6 million produced in 2013. Cumulative production is now more than 1.52 billion barrels of oil which represented approximately 9% of Canada's crude output and 27% of its conventional light crude production.

The price of oil decreased dramatically during the latter half of 2014, as evidenced by Figure 1 below. While production levels and market prices have decreased, oil royalties continued to be the largest single source of revenue (approximately 30%) for the provincial treasury.



Source: U.S. Energy Information Administration

Currently Newfoundland and Labrador has 6% of prospective onshore and offshore land held under licence. The total potential acreage, as outlined on the Sedimentary Basins Map (Figure 2, page 2) is in excess of 80 million hectares offshore and 1.5 million hectares onshore. As illustrated by this map, the numerous offshore sedimentary basins are located throughout Newfoundland and Labrador, whereas the onshore potential is focused around the western portion of the island of Newfoundland only.

Figure 2 - Sedimentary Basins Map

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Petroleum activity in Newfoundland and Labrador is regulated by two distinct authorities. For offshore activity, the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) is responsible, on behalf of the Federal Government of Canada and the Provincial Government of Newfoundland and Labrador, for petroleum resource management. For onshore, the Provincial Government of Newfoundland and Labrador has sole management authority.

The C-NLOPB issues land rights in three different classes: exploration licences, significant discovery licences and production licences. As of December 31, 2014, the C-NLOPB had issued 29 exploration licences, 54 significant discovery licences and 11 production licences (See Appendices A - D). There have been a total of 411 wells spud in the province's offshore area as of December 31, 2014. They comprise 198 development wells, 56 delineation wells and 157exploration wells. The exploration and delineation wells have resulted in 54 significant discovery licences being issued by the C-NLOPB in 25 areas including five on the Labrador Shelf, 19 in the Jeanne d'Arc Basin and one in the Flemish Pass Basin. The C-NLOPB is reporting recoverable reserve/resource estimates for Newfoundland and Labrador's offshore basins at 3.5 billion barrels of oil and 12.2 trillion cubic feet of natural gas as detailed in Table 1 on page 4.

With respect to the onshore area, the Government of Newfoundland and Labrador issues land rights in two categories: exploration permits and production leases. There have been approximately 100 wells spud onshore and as of December 31, 2014 the province had five exploration permits and one production lease on record. The exploration permits onshore, encompassing approximately 160,040 hectares, have been issued in two general areas in western Newfoundland: Flat Bay and Deer Lake. The production lease totaling 1,781 hectares is issued to Enegi Oil Inc. at the Garden Hill South site located on the Port au Port Peninsula.

This report outlines activity that occurred within the producing fields, advances to new developments, exploration activity (geoscience and drilling programs) and changes to land tenure licenses and permits both offshore and onshore in 2014.

Table 1 - Reserves and Resources

Petroleum Reserves1 and Resources2 Newfoundland Offshore Area (Updated December 16, 2014)						
Field	**Oil**		**Gas**		**NGLs**[3]	
	10^6 m^3	million bbls	10^9 m^3	billion cu. ft.	10^6 m^3	million bbls
Grand Banks						
Reserves						
Hibernia	221.9	1644				
Hebron	112	707				
Terra Nova	80.5	506				
Whiterose[4]	37.3	234				
North Amethyst	10.8	75				
Resources						
Hibernia			55.9	1984	35.8	**210**
Terra Nova	13.7	86	1.5	53	0.6	**4**
Whiterose[5]	11.3	71	85.3	3023	15.3	**96**
North Amethyst	0	0	8.9	315	-	**-**
Ben Nevis	40	252	12.1	429	4.7	**30**
Mizzen	16.2	102	-	-	-	**-**
West Bonne Bay	5.7	36	-	-	-	**-**
West Ben Nevis	5.7	36	-	-	-	**-**
Mara	3.6	23	-	-	-	**-**
North Ben Nevis	2.9	18	3.3	116	0.7	**4**
Springdale	2.2	14	6.7	238	-	**-**
Nautilus	2.1	13	-	-	-	**-**
King's Cove	1.6	10	-	-	-	**-**
South Tempest	1.3	8	-	-	-	**-**
East Rankin	1.1	7	-	-	-	**-**
Fortune	0.9	6	-	-	-	**-**
South Mara	0.6	4	4.1	144	1.2	**8**
North Dana	-	-	13.3	472	1.8	**11**
Trave	-	-	0.8	30	0.2	**1**
Ballicatters			32.3	1143	3.3	**21**
Sub-Total	**571.4**	**3852**	**224.2**	**7947**	**63.6**	**385**
Labrador Shelf						
North Bjarni	-	-	63.3	2247	13.1	**82**
Gudrid	-	-	26	924	1	**6**
Bjarni	-	-	24.3	863	5	**31**
Hopedale	-	-	3	105	0.4	**2**
Snorri	-	-	3	105	0.4	**2**
Sub-Total	**0**	**0**	**119.6**	**4244**	**19.9**	**123**
Total	**571.4**	**3852**	**343.8**	**12191**	**83.5**	**508**
Produced[6]	**225.9**	**1417**	**0**	**0**	**0**	**0**
Remaining	**345.5**	**2435**	**343.8**	**12191**	**83.5**	**508**

1 "Reserves" are volumes of hydrocarbons proven by drilling, testing and interpretation of geological, geophysical and engineering data, that are considered to be recoverable using current technology and under present and anticipated economic conditions. Oil reported for Hibernia, Terra Nova, White Rose and North Amethyst fields are classified as reserves.
2 "Resources" are volumes of hydrocarbons, expressed at 50% probability, assessed to be technically recoverable that have not been delineated and have unknown economic viability. Gas, NGLs3, and oil in not approved pools/undeveloped fields are currently classified as resources.
3 "Natural Gas Liquids" (NGLs) are derived from natural gas, which is the portion of petroleum that exists in either the gaseous phase or in solution in crude oil in natural underground reservoirs.
4 White Rose reserves contains South Avalon Pool, the Southern Extension Pool and the West White Rose Pilot Project
5 White Rose Resources contains West Avalon Pool (minus the Pilot Project) North Avalon Pool and Hibernia Reservoir Produced reserve oil volumes as of August 31, 2013. These also include a small quantity of natural gas liquids.
* NGL estimates have not been updated since 2006.

Source: C-NLOPB

2.0 Field Development Overview

2.1 Hibernia - Main Field

Figure 3 - Hibernia Platform

The Hibernia field, the first field development in the Newfoundland and Labrador (NL) offshore region, remains the province's largest offshore oil project in terms of recoverable reserves. The field was discovered in 1979 by Chevron et al with the drilling of the Hibernia P-15 well. The well was drilled approximately 315 kilometers east southeast of St. John's, NL in about 80 meters of water. A fixed production platform consisting of a gravity-based structure (GBS) and topsides drilling and production facilities are being utilized to produce the field. The platform is 224 meters tall, weighs 1.2 million tonnes, and can store 1.3 million barrels of oil. Shipments of oil from Hibernia are offloaded at the purpose built trans-shipment facility at Whiffen Head, Placentia Bay, NL.

Production from the Hibernia field to date has been from two main reservoirs, Hibernia and Ben Nevis/Avalon. Hibernia field development was based on an original reserve estimate of 520 million barrels of oil at an average annual oil production rate (APR) of 110,000 barrels of oil per day (bopd). There have been several increases to the oil reserve estimate and in December 2014, the C-NLOPB increased the recoverable reserves estimated for the Hibernia field to 1.644 billion barrels of oil, 1.984 trillion cubic feet natural gas, and 225 million barrels of natural gas liquids. The current approved allowable production rate for the Hibernia platform is 220,000 barrels of oil per day.

Table 2 - Hibernia Ownership

Hibernia Project Ownership - Main Field	
ExxonMobil	33.125%
Chevron	26.875%
Suncor	20%
Canadian Hibernia Holding Corp.	8.5%
Murphy Oil	6.5%
Statoil ASA	5%

As of December 31, 2014, Hibernia was operating with 62 development wells comprised of 38 oil producers, 19 water injectors, and five gas injectors. Hibernia produced 42.2 million barrels of oil during 2014 for an average daily production of 115,525 barrels. Cumulative oil production to December 31, 2014, was 918.7 million barrels representing 55.9% of the total current reserve estimate.

In June 2009 it was announced that the Hibernia project had reached payout, meaning that all development costs have been recovered. As a result of this milestone, the Province of Newfoundland and Labrador is now receiving a royalty rate of 30% for oil extracted from the main part of the Hibernia field.

Additional drilling around the original Hibernia discovery in 2005 and 2006 confirmed significant upside reserves in the southern portion of the Hibernia field. This area, described as the Hibernia Southern Extension, is divided into two parts: the Hibernia AA Block and the Hibernia South Extension (HSE) Unit. Figure 4, page 8 shows the two sections within the Hibernia Southern Extension.

A Memorandum of Understanding to develop this southern portion of the field was signed with the Province on June 16, 2009. The C-NLOPB approved amendments to the Hibernia Development Plan on August 18, 2009, and September 2, 2010, to accommodate the development of the AA Block and the HSE Unit respectively. Details on each of these projects are outlined in sections 2.1.1 and 2.1.2 of this report. Oil production from both the AA Block and HSE Unit will partially offset the natural production decline at the main Hibernia field and extend the life of field development for the Hibernia platform. It is now expected that the Hibernia platform will continue to produce oil until 2040, which is approximately twenty years longer than originally expected. When natural gas is produced on a commercial basis, this timeframe could be extended further.

2.1.1 Hibernia Southern Extension - AA Block

The Hibernia AA Block includes the AA1 and AA2 blocks in the Hibernia reservoir within Production Licence 1001. The development program for the AA Block included drilling four wells directly from the Hibernia platform. The four well drilling program, which was completed in 2010, consisted of two pairs of oil producers (B-16 57X and B-16 5Z) and water injectors (B-16 37Z and B-16 54V).

With the new December 2014 recoverable reserve estimate for Hibernia, the C-NLOPB has assigned 51 million barrels of oil of the total for the AA Block. Production from the AA Block was estimated to average 11,000 bopd with peak production reaching 25,000 barrels of oil per day (bopd). The projected costs for drilling and tie-in activities of the AA Block development was $196 million CAD and production is expected to last until 2024.

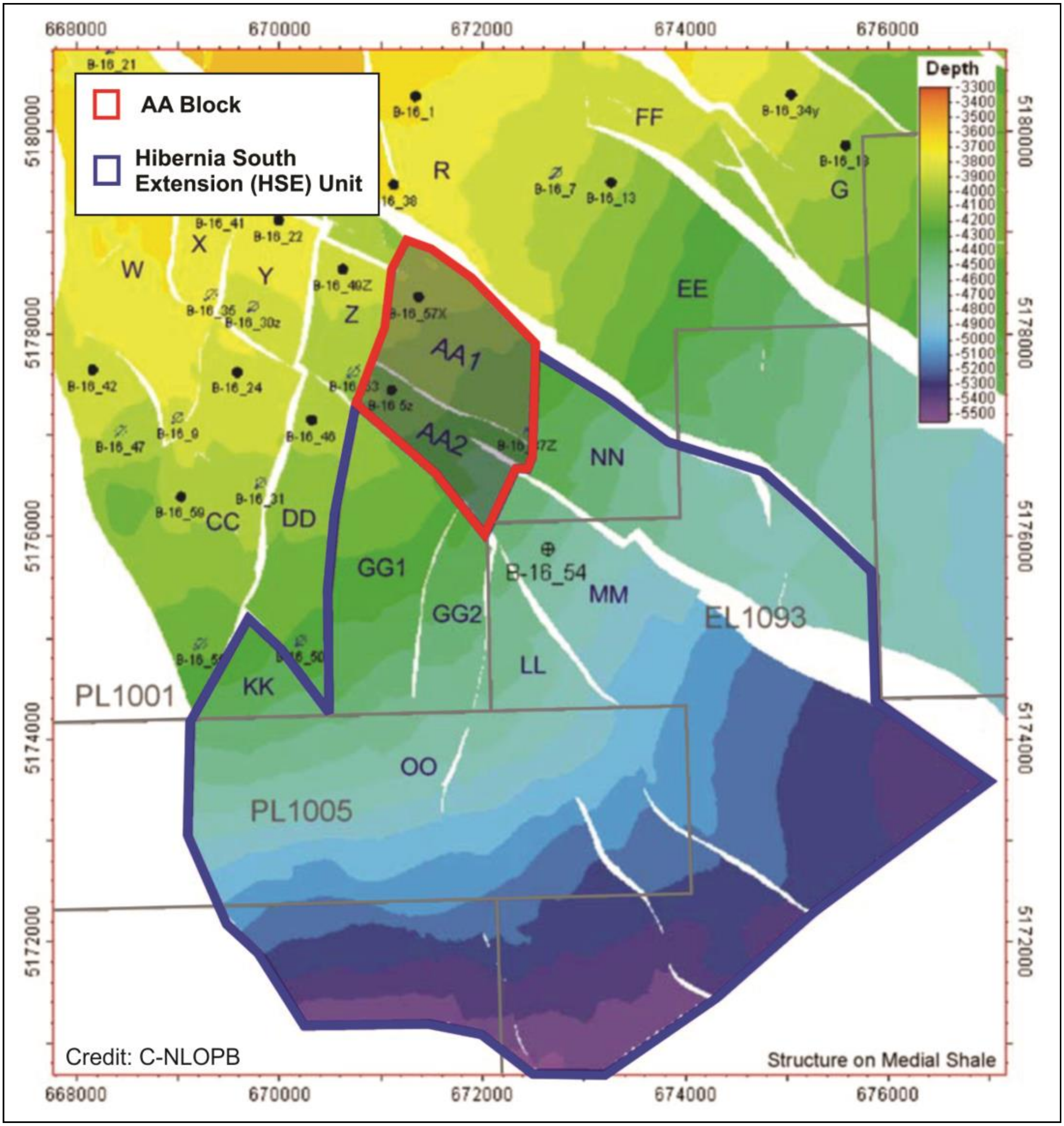
In 2014 production from the AA Block totaled 3.47 million barrels equating to an average daily production of 9,495 bopd. As at December 31, 2014 total cumulative production totaled 36.7 million barrels of oil representing 72% of its total current reserve estimate.

As part of the Hibernia Southern Extension Agreement signed with the Province on February 16, 2010, an equity ownership of 10% was negotiated for Nalcor Energy - Oil and Gas, the Province's wholly owned energy corporation. The purchase price of the ownership position was $30 million CAD and applies to any new development within the Hibernia Southern Extension, exclusive of the AA Block.

The ownership structure for the AA Block therefore remains the same as the original Hibernia main field as detailed in Table 2, page 6. In addition, Nalcor Energy agreed to cover 10% of future development costs of the Hibernia Southern Extension in return for 10% of oil production.

The new agreement with the Provincial Government also includes an enhanced royalty rate of 42.5% from oil produced from the existing GBS within Hibernia Southern Extension. This new rate would therefore apply to production from the AA Block. The rate will increase to 50% once the terms of the supplementary royalty payout are achieved under the original Hibernia royalty contract.

Figure 4 - Hibernia Southern Extension
Southern Extension Unit Area



Source: HMDC

2.1.2 Hibernia Southern Extension - Hibernia South Extension (HSE) Unit

As part of development plan amendments approved by the C-NLOPB, the interest holders in Production Licences 1001 and 1005 and Exploration Licence 1093 were granted the right to develop the Hibernia reservoir located in the Hibernia South Extension (HSE) Unit as shown in Figure 4, page 8. The additional area in the amendment includes the GG, KK, LL, MM, NN, and allowances are made to include the OO fault blocks should drilling results prove positive. In 2012, portions of the HSE Unit held under Exploration Licence 1093 that are to be developed were transferred to Production Licence 1011 with the individual and unitization ownership positions as shown in Table 3 below.

Table 3 - HSE Project Participants

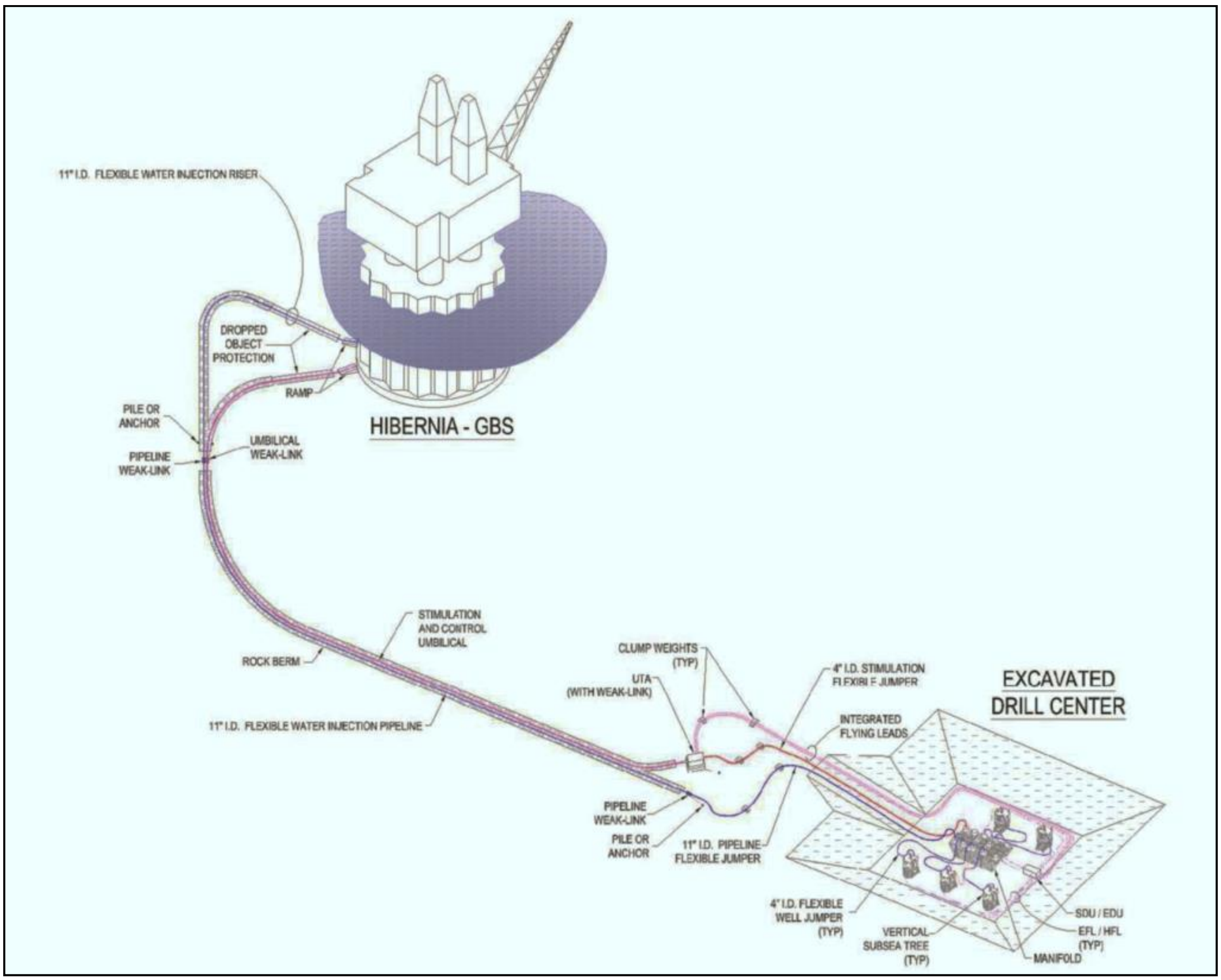
HSE Project Participants	EL 1093	PL 1005	PL 1011	Unitization Interest
ExxonMobil Canada	29.8125%	22.5%	29.8125%	27.4 %
Chevron Canada Resources	24.1875%	22.5%	24.1875%	23.6 %
Petro-Canada Hibernia Partnership	18%	22.5%	18%	19.5 %
Statoil Canada Ltd.	4.5%	22.5%	4.5%	10.5 %
Nalcor Energy	10%	10%	10%	10 %
Canada Hibernia Holding Corp.	7.65%	0%	7.65%	5.1%
Murphy Oil	5.85%	0%	5.85%	3.9 %

The C-NLOPB is now estimating recoverable reserves in the HSE Unit at 199 million barrels of oil. Note that this figure is also included in the 1.644 billion barrels of oil reserve estimate for the Hibernia field. The total cost of the HSE development was estimated at $1.735 billion, with the drilling program expected to account for approximately $1.1 billion of the total.

The approved development plan for the HSE Unit consists of drilling ten wells comprising five pairs of oil producers and water injectors. The production wells will be drilled from the Hibernia platform utilizing existing GBS slots whereas the water injectors will be drilled from a semi-submersible offshore drilling unit. Dredging for the excavated drill centre as shown in Figure 5, page 10, located approximately seven kilometers southeast of the Hibernia GBS, to house the subsea templates and manifolds for the water injection wells was completed in 2012. During 2014, development continued in the field with platform related tie-ins and commissioning of flowlines, jumpers, and subsea equipment for water injection.

Drilling of the production wells commenced in 2011 with first oil from wells B-16 47Z and B-16 42Z occurring on June 25, 2011, and September 30, 2011, respectively. The third oil producer (B-16 38 HIBB2) was brought on-line temporarily in February 2014 for testing. Water injection continued in

Figure 5 - Hibernia Southern Extension Development



Source: Stantec 2012 Environmental Assessment Review

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with the completion of the second water injector P-02 1Z by the West Aquarius drilling rig. Oil production for 2014, was 1.1 million barrels giving an average daily production of 2,962 bopd. Total cumulative production to December 31, 2014, was 4.64 million barrels of oil which represents approximately 2.3% of the total recoverable reserve estimate for the HSE Unit.

The signing of the Hibernia South Development Agreement on February 16, 2010, included new fiscal measures encompassing production from the southern portion of the Hibernia field. The new fiscal measures included a 10% ownership position for Nalcor Energy - Oil and Gas, exclusive of the AA Block development, and an enhanced royalty structure for all production covered within the Hibernia South Extension area. The royalty framework is divided between production from land licenced under the original Production Licence 1001 and land licenced under both the Production Licence 1005 and Exploration Licence 1093 (now Production Licence 1011).

With respect to production from the HSE Unit from within the original PL-1001, the royalty framework will start with the current basic royalty rate of 30%. This rate increases to 37.5% when the price of West Texas Intermediate (WTI) crude oil exceeds $50 USD per barrel and then increases to 42.5% when the price of WTI crude exceeds $70 USD per barrel. A top royalty rate of 50% will be applicable when the project meets the terms of the supplementary royalty payout under the terms of the original Hibernia royalty contract.

The new royalty structure for oil production from lands licenced under PL-1005 and PL-1011 calls for a basic 5% royalty rate from first oil. This rate increases to a Tier 1 rate of 30% when payout occurs on the project. The rate rises to 32.5% when WTI crude pricing exceeds $50 USD per barrel and then increases further to 37.5% when WTI pricing exceeds $70 USD per barrel. A top royalty rate of 50% will be applicable when the project meets the terms of the supplementary royalty payout under the terms of the original Hibernia royalty contract.

2.2 Terra Nova Field

The Terra Nova field was discovered by Petro-Canada (now Suncor Energy) in 1984, about 35 kilometers southeast of Hibernia, in about 90 meters of water. The discovery well, Terra Nova K-08, located about 350 kilometers southeast of St. John's, NL, flow-tested 10,000 barrels of oil per day from the Jeanne d'Arc reservoir. Five subsequent successful delineation wells tested at rates ranging from 5,000 to 25,000 bopd.

Table 4 - Terra Nova Project Ownership

Terra Nova Project Ownership	
Suncor	37.675
ExxonMobil	19%
Husky Oil	13%
Statoil ASA	15%
Murphy Oil	10.475%
Mosbacher	3.85%
Chevron	1%

The field is being developed using a Floating Production Storage and Offloading (FPSO) vessel and first oil was produced on January 20, 2002. The Terra Nova FPSO was the first of its kind to be used in North America and included the largest disconnectable turret mooring system in the world. The vessel is double hulled with oil cargo tanks capable of holding up to 960,000 barrels of oil.

Figure 6 - Terra Nova FPSO in Marystown

Source: Department of Natural Resources

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The latest recoverable reserve/resource estimate for the Terra Nova field, released in April 2013, includes 592 million barrels of oil, 53 billion cubic feet of natural gas, and 4 million barrels of natural gas liquids. The approved allowable production rate for the Terra Nova FPSO is 180,000 barrels of oil per day and it is forecasted to stay into production until 2027.

As of December 31, 2014, Terra Nova was operating with a total of 30 development wells, consisting of 17 oil producers, ten water injectors, and three gas injectors. Total field production for 2014 was 16.76 million barrels of oil which equates to an annualized production of 45,924 bopd. Cumulative field production to the end of 2014 was 366.1 million barrels of oil which represents 61.8% of the current recoverable reserve estimate.

The Skandi Constructor (shown in Figure 7 below) is a 120-metre well intervention vessel that was used at the Terra Nova field in 2014. Well intervention vessels use wire-line technology to log and identify wells with high water content, and are able to isolate the water to maximize the recovery of oil and gas. The Skandi arrived onsite in August and entered four wells in the forty day program . This was the first time such a vessel was utilized in Newfoundland and Labrador's offshore to improve recovery from existing production wells.

Figure - 7 Skandi Constructor

Source: DOF Subsea

2.3 White Rose Field

In 1984, Husky Energy discovered the White Rose field by drilling the White Rose N-22 exploration well in water depths of approximately 120 meters. The discovery well tested at 900 barrels of oil per day, 25 million cubic feet per day of natural gas and 840 barrels per day of condensate. The field consists of one principle reservoir, the Ben Nevis/Avalon, and is located 350 kilometers south-east of St. John's, NL, in the Jeanne d'Arc Basin. Similar to the Terra Nova field, the White Rose field is being developed using a FPSO. The White Rose FPSO, named the SeaRose, has a storage capacity of 940,000 barrels of oil and an approved allowable production rate of 137,000 barrels of oil per day. First oil was produced at the White Rose field on November 15, 2005.

Table 5 - White Rose Project Ownership

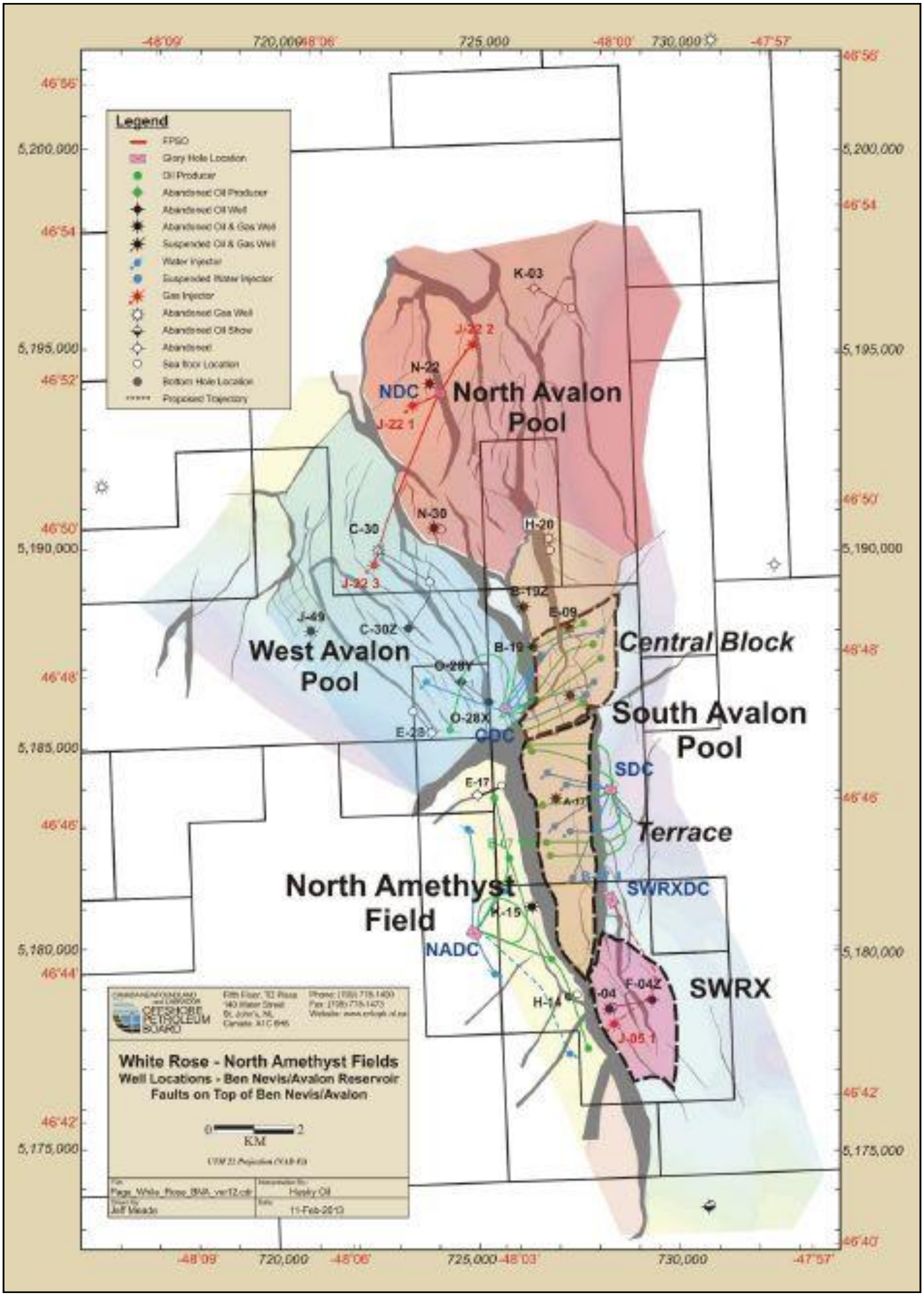
White Rose Project Ownership	
Husky Energy	72.5%
Suncor	27.5%

The C-NLOPB has assigned recoverable reserve/resource estimates for the field at 305 million barrels of oil, 3.02 trillion cubic feet of natural gas, and 96 million barrels of natural gas liquids. These estimates include reserves/resources contained in the main White Rose field (South Avalon Pool), the South White Rose Extension (SWRX) Pool, the West Avalon Pool, and the North Avalon Pool. Figure 9, page 15 shows the location of the various pools. These estimates, however, do not include recoverable resource estimates of 75 million barrels of oil and 315 million cubic feet of natural gas located in the North Amethyst field, which is adjacent to the White Rose field and discussed in more detail in Section 2.4 of this report. Production from the North Amethyst field is also being processed by the SeaRose FPSO through a subsea tie-back.

Figure - 8 White Rose FPSO - Sea Rose

Source: Department of Natural Resources

Figure - 9 White Rose Development Area



Source: C-NLOPB

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Oil production in 2014 from the main White Rose field and the West White Rose pilot program discussed in section 2.3.1 totaled 11.9 million barrels oil, which equates to an annualized daily production of 32,490 bopd. Total cumulative production as of December 31, 2014, was 198.4 million barrels, which represents 65% of the total reserve estimate. The main field and the West White Rose pilot program are being developed utilizing 23 development wells, consisting of ten producers, ten water injectors, and three gas injectors.

In 2008, the co-venture partners, Husky Energy and Petro-Canada (now Suncor Energy), and the Province of Newfoundland and Labrador, through Nalcor Energy, signed a development agreement for lands surrounding the original White Rose development.

As part of this agreement, Nalcor agreed to purchase a 5% equity stake in the project at a cost of $30 million CAD, subject to a confirmation of reserve estimates. The terms of the original White Rose development remain unchanged. The first of the three extensions, North Amethyst, was brought on line in 2010 and work continues to develop the SWRX and the West Avalon Pool. Details on these two new projects are outlined in Sections 2.3.1 and 2.3.2 respectively.

Late in 2012, Husky Energy announced that it had reached an agreement with Seadrill Limited for the long term lease of the semi-submersible drilling rig West Mira. The West Mira (See Figure 10 adjacent) is currently under construction at the Hyundai Samho Shipyard in South Korea with an expected completion date late in 2015. After testing and commissioning, the rig will commence transit to Newfoundland with an estimated start date of late 2015/early 2016. The West Mira is a 6th generation drilling rig and will be fully winterized. The contract is valued in excess of $1.0 billion and will run for a five year term. It is expected that the unit will be involved in exploration and production programs for Husky at its various licences.

Figure 10 - West Mira Drilling Rig - Korea

Source: Seadrill

2.3.1 West White Rose Extension

Development of the West White Rose portion of the field (re: West Avalon Pool see Figure 9, page 15) has been under analysis by the partners since 2001. In 2010, a development plan amendment was submitted and approved by the C-NLOPB allowing for the drilling of a two-well pilot scheme at West White Rose to further assess the viability and feasibility of field development. The first development well, oil producer E-18-10, was spud on April 23, 2010, and commenced oil production on September 5, 2011. The second well, water injector E-18-11, was completed early in 2012. In 2014, West White Rose produced 2.93 million barrels of oil raising total cumulative production at the extension to 8.8 million barrels. Note that this production is included in the overall cumulative production for the White Rose field as detailed in Section 2.3 of this report.

The initial estimated cost for the West White Rose pilot scheme was $250 million CAD, which included a $130 million CAD drilling program and $120 million CAD for subsea infrastructure. The C-NLOPB has assigned a resource estimate for the West White Rose pool at 40 million barrels of oil. This amount is included in the total reserve/resource estimate for the White Rose field, as detailed in Section 2.3, however, this figure could be revised once a full analysis of the results of the pilot scheme is complete.

Since completion and analysis of the results of pilot project Husky Energy and partners have been investigating two development options: subsea infrastructure and a gravity based wellhead platform. With the signing of the benefits agreement for the construction of the wellhead platform with the Government of Newfoundland and Labrador in 2013 indications were that the wellhead platform was the preferred development route. Pre-sanctioning work for the wellhead platform began with the start of construction of a graving dock in Argentia, NL. However, in December 2014 with the sharp decline in oil prices and rising construction costs Husky Energy announced that they would delay the final sanctioning decision by one year until late in 2015. During this period the company stated that it would be re-evaluating the two development options to find cost and operating efficiencies and then make a sanctioning decision on the preferred development plan.

2.3.2 South White Rose Extension

A development plan amendment was approved by the C-NLOPB in 2007 for the South White Rose Extension (SWRX), contained within Production Licence 1007. The plan called for a subsea tie-back to the SeaRose FPSO through the existing southern excavated drill centre, as well as a new drill centre to be constructed approximately 4 kilometers further south. The C-NLOPB have assigned a resource estimate for the South White Rose Extension of 22 million barrels of oil, which is also included in the total reserve/resource estimate for White Rose as detailed in Section 2.3.

In June, 2013, the C-NLOPB approved a development plan amendment to the South White Rose Extension to accommodate the production of oil reserves in the South White Rose Extension pools and also some adjacent reserves in South Avalon Pool that are currently not accessible by existing infrastructure.

The plan included the construction of a drill centre in the SWRX area and the drilling of six development wells that will be located in the new drill centre. Four of the six development wells, consisting of two oil producers, one water injector, and one gas injector, will be used to produce oil from the South White Rose Extension area.

The balance of the two development wells, consisting of an oil producer and a gas injector, will be drilled in the South Avalon Terrace in the main White Rose field. It is expected that these development wells will produce a total of 33 million barrels of oil with 24 coming from the South White Rose Extension area and 9 million barrels of oil from the South Avalon Terrace area of the main field.

Work began in 2012 with the dredging of the new SWRX drill centre and in 2013 a new gas injector was completed. SWRX tie-in was completed in September, 2014 and oil producer J-05 2 was spudded on November 28, 2014. Initial production for SWRX is planned for mid 2015. The total cost of the project was projected at $1.2 billion CAD including $590 million for drilling and completions and $495 million for subsea infrastructure.

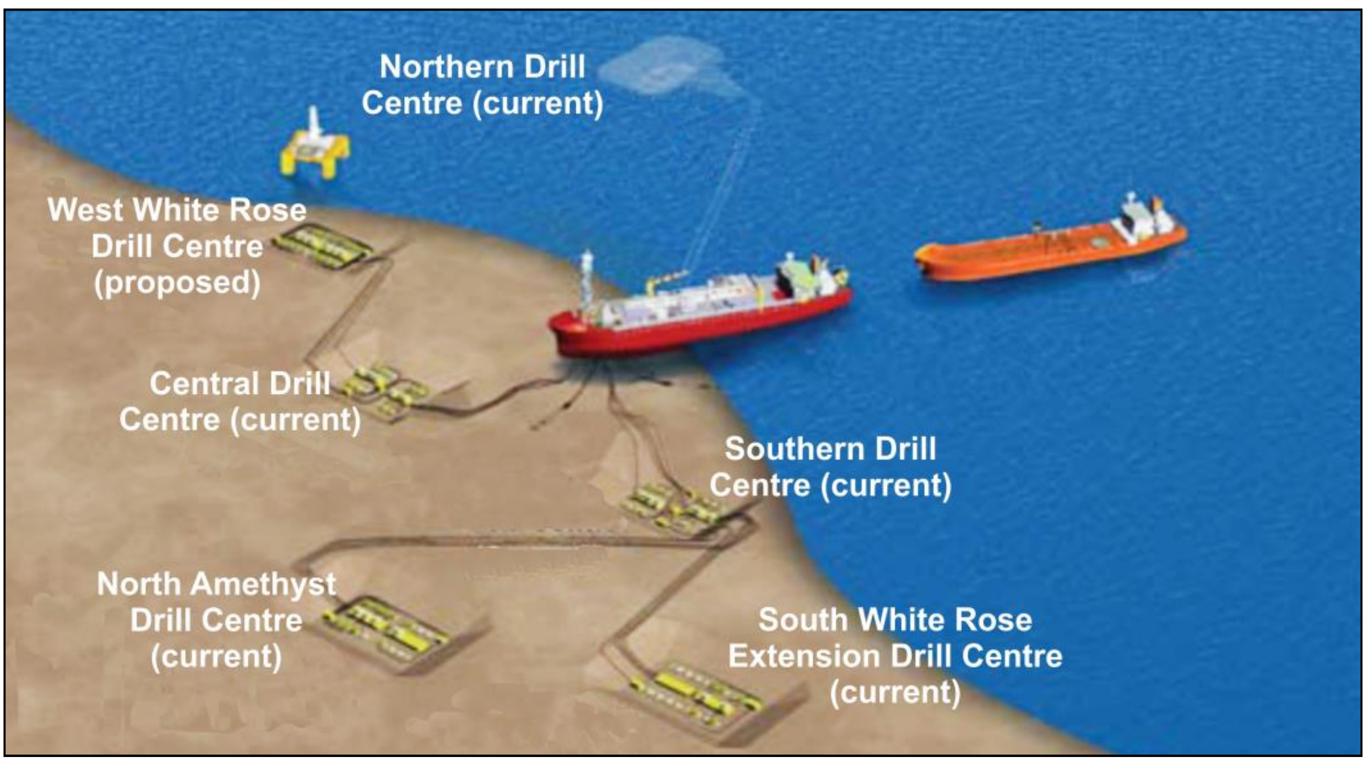
2.4 North Amethyst Field

North Amethyst Project Ownership	
Husky Energy	68.875%
Suncor	26.125%
Nalcor	5%

The North Amethyst field was the first of the satellite pools to be developed in the Jeanne d'Arc Basin. Figure 11 below shows the location of the North Amethyst field within the Jeanne d'Arc Basin. It was identified by exploratory drilling in 2006 and the C-NLOPB reported recoverable reserve/resource estimates of 75 million barrels of oil and 315 billion cubic feet of natural gas in the Ben Nevis/Avalon and Hibernia formations.

The initial estimated capital cost to develop North Amethyst was $1.5 billion CAD including $705 million CAD for drilling and completions and $587 million CAD for subsea development. Flexible underwater flowlines connect the field to the SeaRose FPSO, which is located approximately 6 kilometers away. Initial production from North Amethyst occurred on May 31, 2010, from the oil well G-25 2.

Figure 11 - White Rose Tie Back Development via SeaRose FPSO



Source: Husky Energy

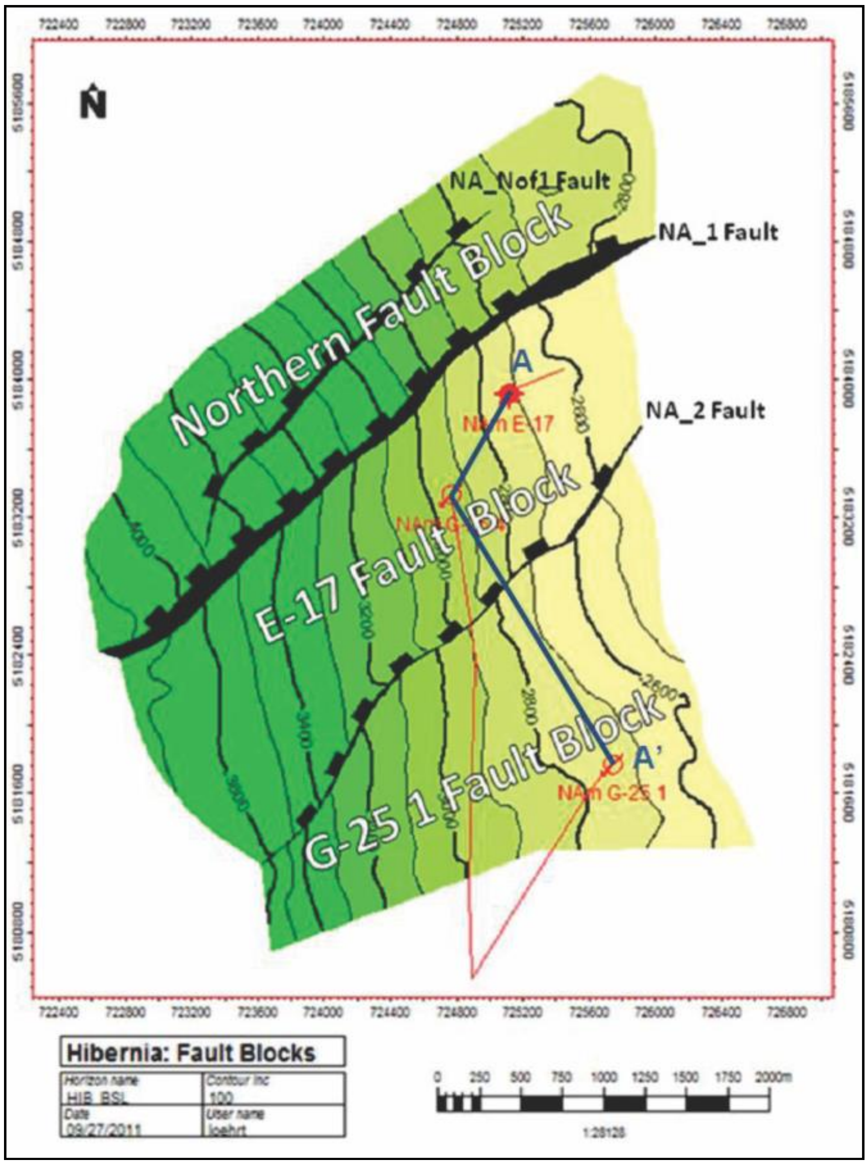
2014

As of December 31, 2014, North Amethyst was operating with nine development wells, consisting of five oil producers and four water injectors. Total oil production in 2014 was 8.1 million barrels of oil for an average production of 22,091 bopd. Cumulative production to December 31, 2014, was 39.5 million barrels representing 52.6% of the current total recoverable reserve estimate.

Production from North Amethyst in 2010 was an important milestone as it represented production from Canada's first offshore satellite tieback project. The additional production from North Amethyst, and other near field developments, will slow the decline in production at the SeaRose FPSO and extend its life.

In 2009, Husky Energy announced that additional resources were discovered at North Amethyst in the lower Hibernia Formation. In 2013, the C-NLOPB approved a development plan amendment to recover 6.73 million barrels of oil from the Hibernia Formation (Figure 12 adjacent). It is anticipated that the North Amethyst Hibernia development will consist of one production well and one water injection well. Husky previously completed a dual zone water injection well, North Amethyst G-25 4, in 2010 for both the Ben Nevis/Avalon and Hibernia Formations. The North Amethyst Hibernia development producer, E-18 12Z, was spudded in Sept, 2014 with completions planned for 2015.

Figure 12 - North Amethyst Hibernia fault blocks and well locations



Source: Husky Energy

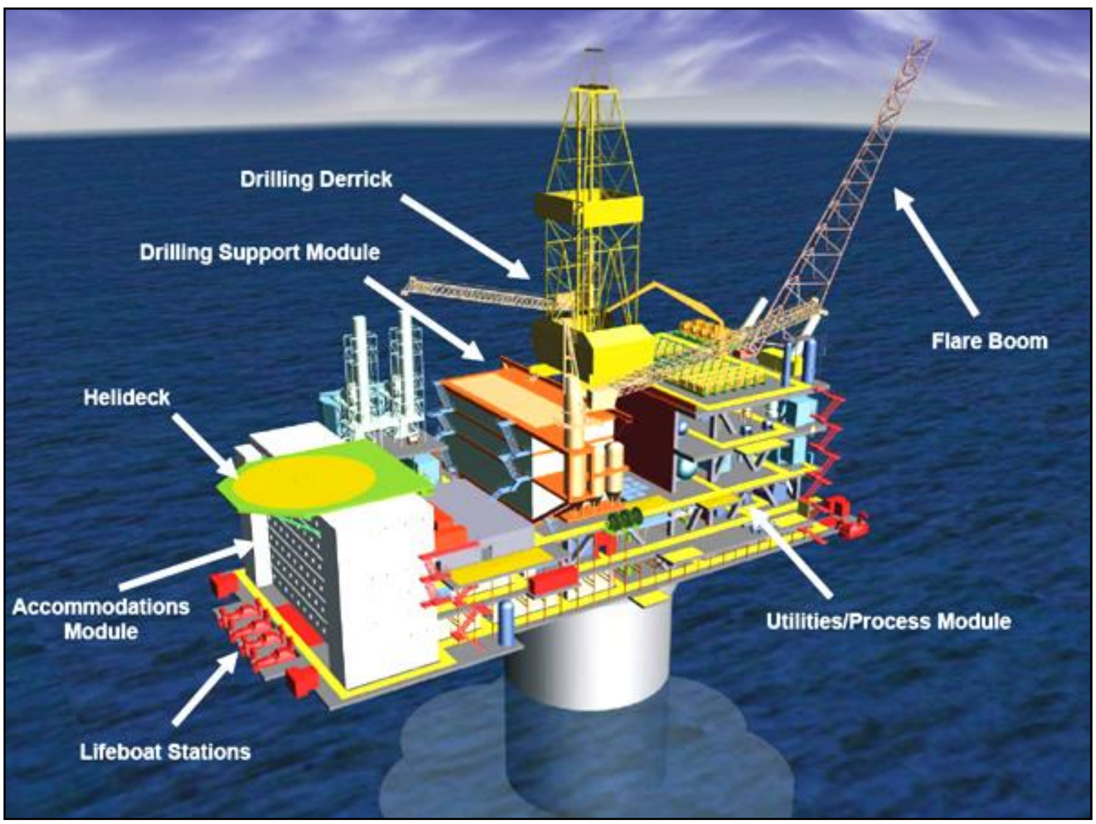
2.5 Hebron/Ben Nevis Field

Hebron Project Ownership	
ExxonMobil	36.0429%
Chevron	26.628%
Suncor	22.7289%
Statoil ASA	9.7002%
Nalcor	4.9%

The Hebron field was discovered in 1981 when the Mobil et al Hebron I-13 discovery well recovered hydrocarbons from five intervals with a combined flow rate of 9,070 barrels of oil per day. The field is located in the Jeanne d'Arc Basin, approximately 32 kilometers southeast of Hibernia, 9 kilometers north of Terra Nova, and 46 kilometers southwest of White Rose. The water depth in the area ranges from 88 to 102 meters of water. The adjacent Ben Nevis and West Ben Nevis fields that lie to the northeast of Hebron were discovered in 1980 and 1984 respectively .

The C-NLOPB have assigned a reserve estimate for the Hebron field at 707 million barrels of recoverable oil. Estimates by the C-NLOPB for the Ben Nevis and West Ben Nevis discoveries include an additional 288 million barrels of oil, 429 billion cubic feet of natural gas, and 30 million barrels of natural gas liquids.

Figure - 13 Proposed Hebron Development



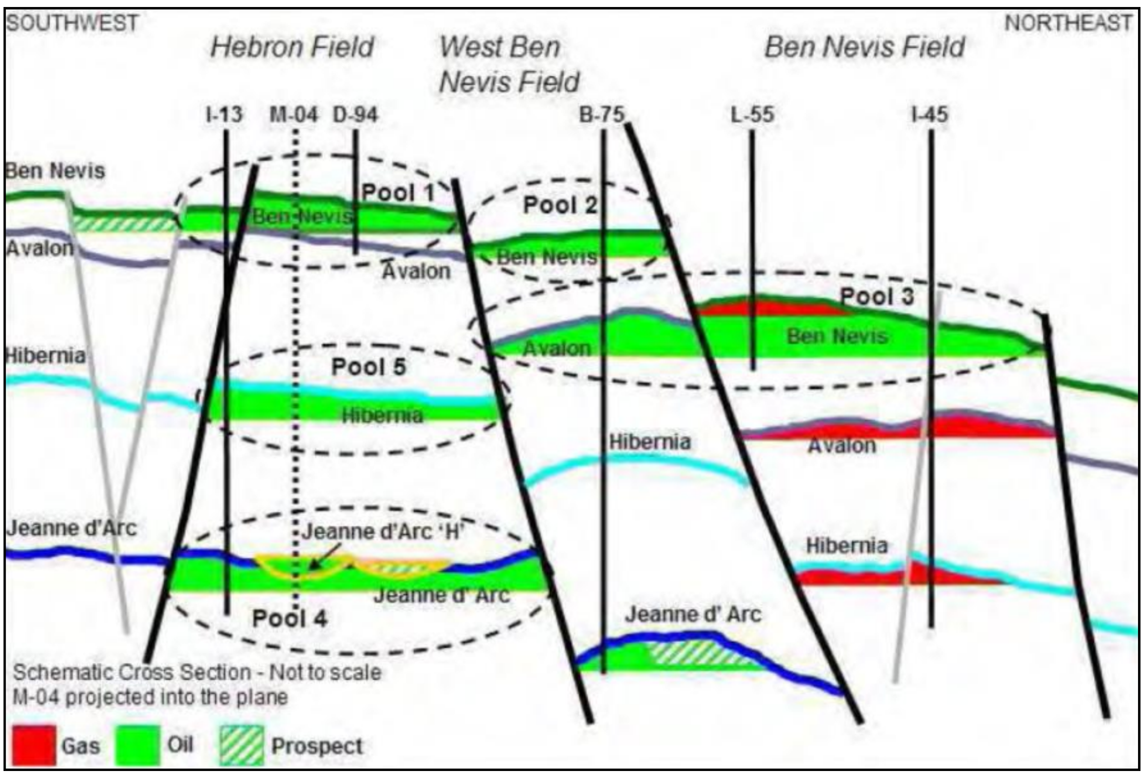
Source: ExxonMobil

Formal agreements were signed with the co-venture partners and the Government of Newfoundland and Labrador to develop the Hebron offshore project on August 20, 2008. As part of the agreement, Nalcor Energy - Oil and Gas purchased a 4.9% stake in the project at a cost of $110 million CAD. It was also agreed that Nalcor would pay a proportionate share of the project development costs and in return would receive a similar share of production.

In 2011, ExxonMobil submitted the Hebron Development Plan to the C-NLOPB and in 2012, the C-NLOPB approved the development plan, subject to certain terms and conditions. The co-venture partners completed a review of all recommended terms and conditions and sanctioned the Hebron project on December 31, 2012.

The Hebron/Ben Nevis area consists of five oil reservoirs (pools) as outlined in Figure 14, adjacent. The main Hebron field includes pool 1 followed in a vertically stacked arrangement by pools 5 and 4 respectively.

Figure 14 - Schematic cross-section across the Hebron Asset area



Source: ExxonMobil

Slightly to the northeast is the West Ben Nevis field, which contains pool 2, and further northeast is the Ben Nevis field, which includes pool 3. The Hebron Development Approval includes producing oil from the Hebron field only and any production from the Ben Nevis and West Ben Nevis fields will require additional approvals from the C-NLOPB.

Hebron will be developed using a gravity based structure (GBS) similar to albeit on a smaller scale than the Hibernia GBS. Due to changes with final design and engineering, in 2013 the estimated capital costs for the Hebron project was increased and projected at $14 billion CAD. Construction of the GBS commenced in October 2012 with the installation of the steel base skirt. In 2012, Kiewit Kvaerner Contractors (KKC), a 50-50 joint venture between Peter Kiewit Infrastructure and Kvaerner ASA, was awarded the contract for the slip forming of the GBS structure.

KKC was previously involved in the Hebron project as it held the contract for the FEED portion for the GBS. In 2013, the concrete GBS structure was slip formed to a height of 27 meters and the dry dock was flooded in June 2014 in preparation to float the GBS to its deepwater construction site (See front cover photo). On July 22, 2014, it took 10 hours to successfully tow the 180,000 ton Hebron GBS from the dry dock to the deepwater construction site at Bull Arm. At the deepwater site the floating GBS continues to be slipped formed to a height of 120 metres. Upon completion of the GBS, expected in 2015, the topsides will be floated over and set on the GBS to form the complete platform that will be installed at the Hebron field.

In 2012, WorleyParsons was awarded the engineering, procurement, and construction contract for the topsides. It was also announced that US engineering company, Fluor Corporation, would assist WorleyParsons with overall project management. Design of the topsides facility call for it to be assembled from seven individual components and/or modules. These include the utilities and process module, the drilling support module (DSM), the drilling equipment set (DES), the living quarters, the helideck, the flare boom, and the lifeboat stations (see Figure 13 on page 21).

Contracts for construction of the various components have been awarded to the following:

1/ Utilities and Process Module - Hyundai Heavy Industries, Korea.

2/ Drilling Equipment Set - Hyundai Heavy Industries, Korea

3/ Drilling Support Module - Kiewit Offshore Services, Marystown, NL (See Figure 15, page 24)

4/ Living Quarters - North Eastern Contractors (a partnership of the local Cahill Group of Companies and Apply Leirvik based in Norway)

5/ Helideck - C&W Offshore, Bay Bulls, NL

6/ Life Boat Station - C&W Offshore, Mount Pearl, NL

7/ Flare Boom - Talon Energy Services, Port aux Basques, NL

ExxonMobil have stated that the integration of all completed modules remains on schedule for 2016 with first oil in 2017. The platform is designed for maximum production of 150,000 barrels of oil per day with a 30 year lifespan.

Figure 15 - Cow Head Fabrication Facility Located at Marystown

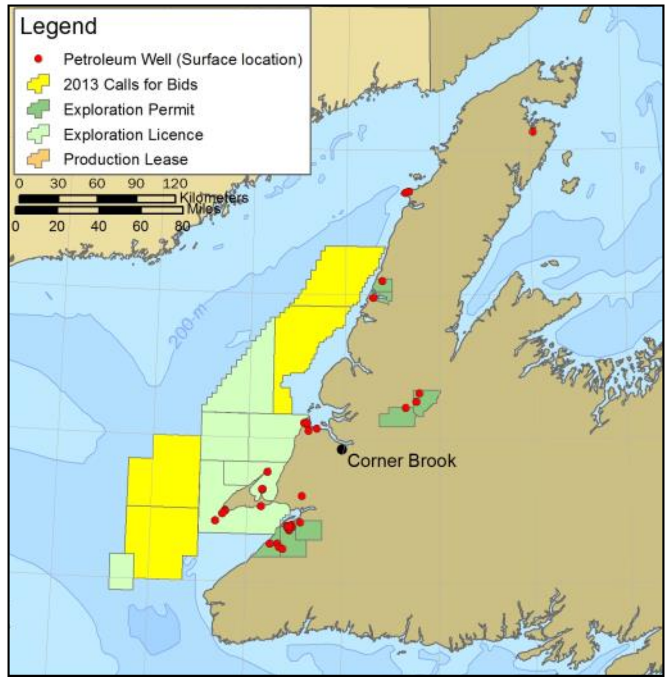
Source: Department of Natural Resources

2014

2.6 Garden Hill South Field

Garden Hill South is located onshore western Newfoundland on the Port au Port Peninsula, as identified in Figure 16, adjacent. In 2012, land associated with the Garden Hill South oil pool covered under the production lease 2002-1(A) issued by the Province of Newfoundland and Labrador was renewed for a further five year term. Also in 2012, the operator of the production lease changed its name from PDI Production Inc. to Enegi Oil Inc - a subsidiary of Enegi Oil Plc. based in Salford, Manchester, United Kingdom.

Figure 16 - Port au Port Peninsula



Activity at the Garden Hill site commenced in September 1994 when Hunt/Pan Canadian drilled the Port au Port (PAP) 1 well. The well encountered two hydrocarbon bearing intervals within the Aguathuna Formation dolostones with flow rates of 1,528 and 1,742 barrels of 51 degree API oil and 2.6 and 2.3 million cubic feet of natural gas per day.

Several sidetrack wells have been drilled at the PAP 1 well to determine the overall field size and the potential long term oil production that could be achieved. Workover programs and extended production tests were completed on the PAP 1 Sidetrack 3 between 2010 - 2012 and during 2013 - 2014 intermittent production occurred. In 2014 a total of 927 barrels of oil was recovered raising the total cumulative production at the Garden Hill South site to approximately 42,800 barrels of oil.

In December, 2014, Enegi Oil announced that the farm-in agreement with Black Spruce Exploration for a five well development program announced in 2013 was mutually dissolved. Enegi Oil also announced that they will be developing an incremental work program that provides the most appropriate route to further prove reserves to develop the area.

2014

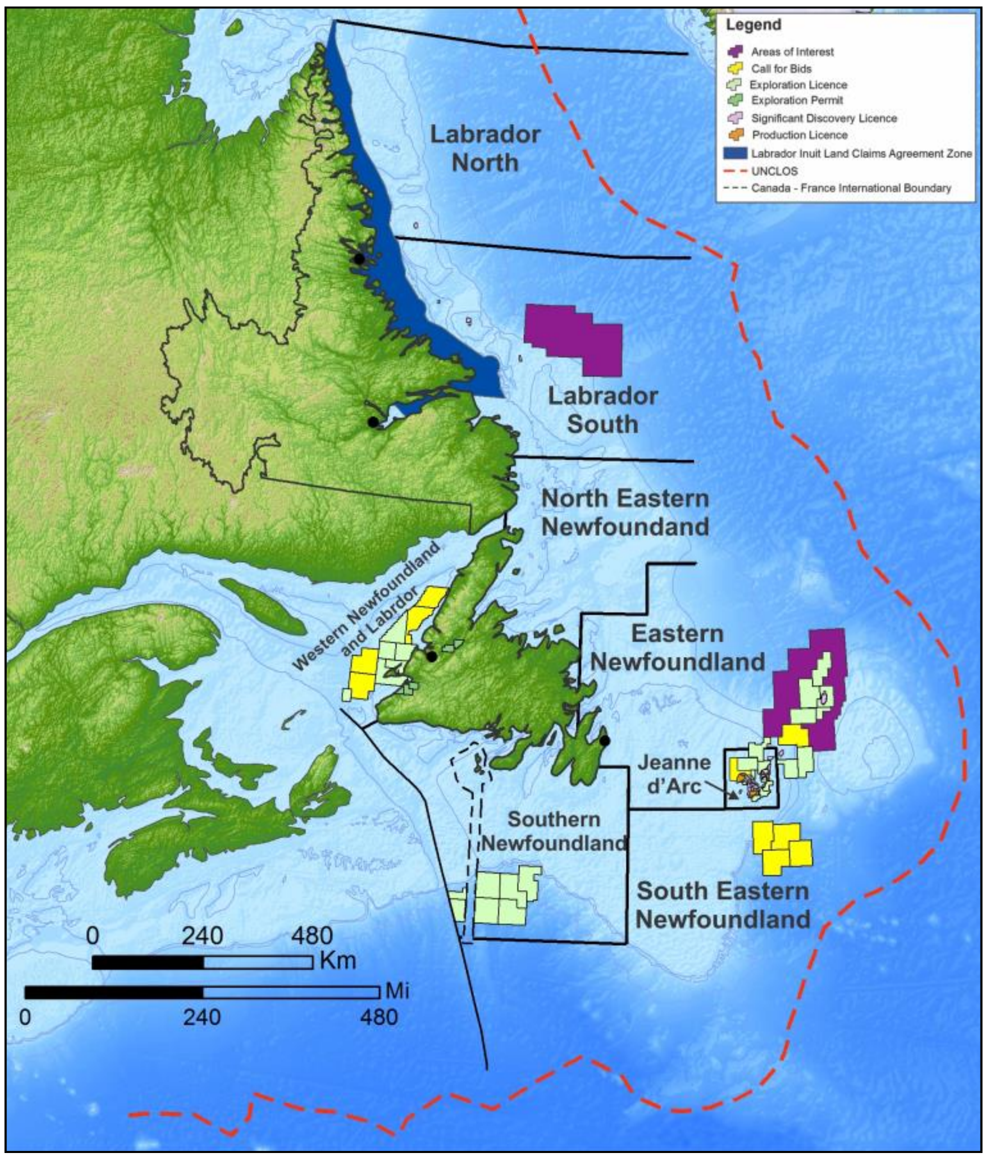
3.0 Regional Activity Overview

3.1 Scheduled Land Tenure System - Overview

In 2013, the C-NLOPB implemented a new Scheduled Land Tenure System to provide increased lead times for calls for bids in frontier areas. The new system divides the offshore into eight regions based on the level of historical exploration activity. Scheduled licensing rounds will be held in each region on either a one, two, or four year cycle, offering explorers additional time to evaluate the resource potential, and opportunities, in the lesser explored basins of the province.

Figure 17 adjacent shows the breakdown of the various offshore regions around the province. The Jeanne d'Arc region will operate on a one year cycle while Eastern Newfoundland will operate on a two year cycle. All other regions of the province will follow the four year cycle.

Figure 17 - Scheduled Land Tenure Regions



2014

In the Scheduled Land Tenure System, the rights issuance process will commence with a Call for Nominations (Areas of Interest). The C-NLOPB will consider all nominations received for the Areas of Interest and then seek nominations for sectors within each Area of Interest. The C-NLOPB will then issue a Call for Nominations (Parcels) for parcels within each sector which will ultimately lead to a Call for Bids (Parcels) for identified parcels within the sector. As mentioned previously, the level of exploration activity within each region will determine the length of time allocated for the Call for Nomination and Call for Bids processes within the cycle.

Further information on the new Scheduled Land Tenure System can be found on the C-NLOPB website at **www.cnlopb.ca/exploration/issuanceprocess.php**

3.2 Licensing Round Results

There were four Calls for Bids that closed late in 2014 offering ten parcels of land totaling 2,517,958 hectares. Note that Exploration Licenses will be issued to the successful bidders early in 2015 when all terms and conditions are met.

3.2.1 Calls for Bids 2013 Results

Call for Bids NL13-01 (Figure 18 adjacent) consisted of a single parcel of land in the Flemish Pass area totalling 266,139 hectares. Based upon the single work commitment criteria, the winning bid in the amount of CAD $559 million, was submitted by ExxonMobil Canada Ltd. 40%, Suncor Energy Inc. 30% and ConocoPhillips Canada Resources Corp. 30%.

Figure 18 - NL13-01 Call for Bids

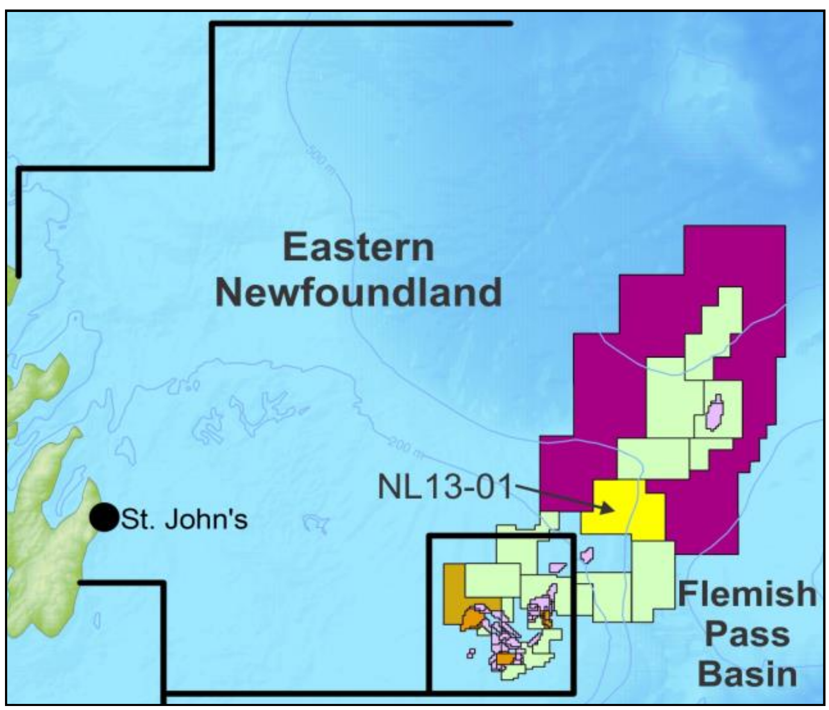
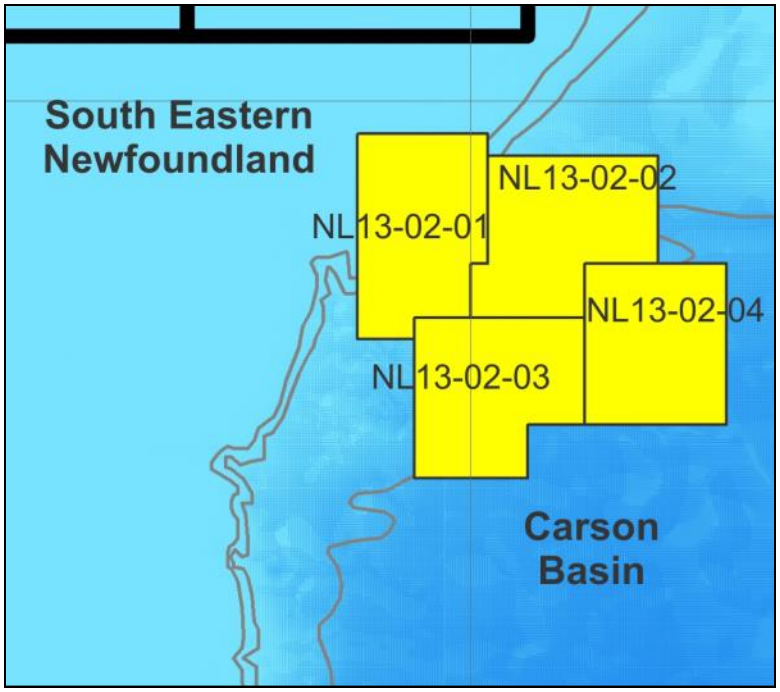


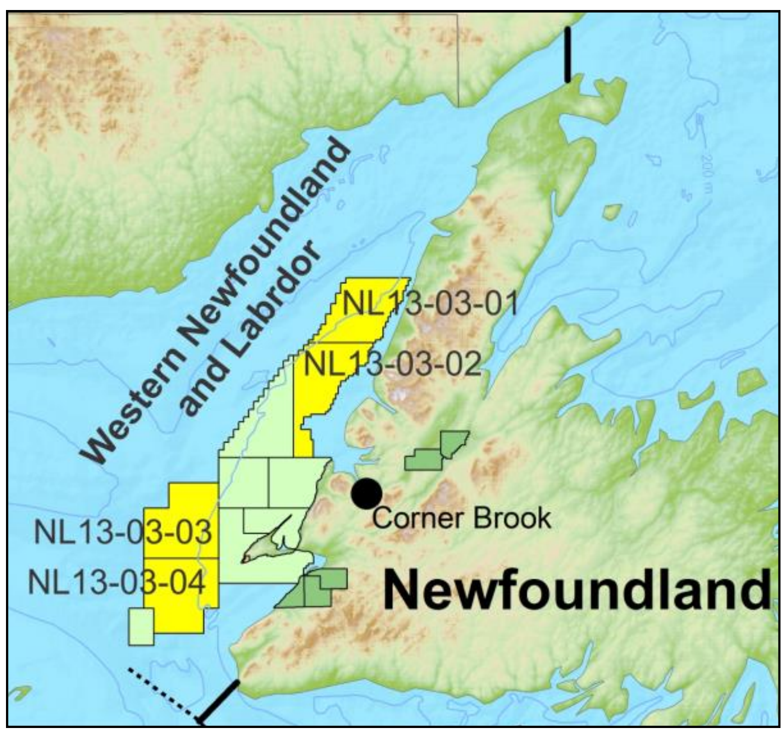
Figure 19 - NL13-02 Call for Bids



Call for Bids NL13-02 (Figure 19 adjacent) consisted of four parcels of land in the Carson Basin area totaling 1,138,399 hectares. Based upon the single work commitment criteria, the winning bid for Parcel #2 (NL13-02-02) in the amount of CAD $21 million was submitted by ExxonMobil Canada Ltd. 50% and Suncor Energy Inc. 50%. Note no bids were received for parcels 1, 3 and 4.

Figure 20 - NL-13-03 Call for Bids

Call for Bids NL13-03 (Figure 20 adjacent) - Western Newfoundland and Labrador Offshore Region consisted of four parcels. Note no bids were received.

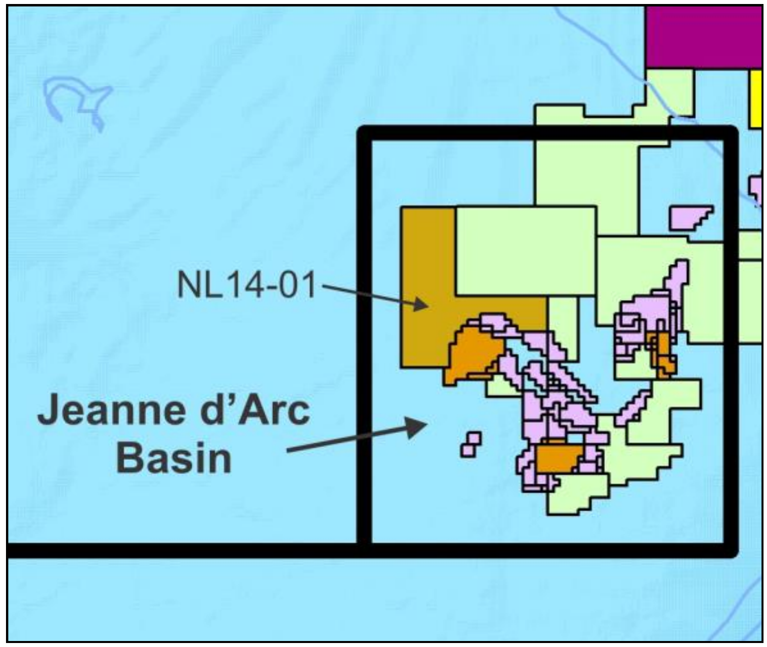


3.2.2 Call for Bids 2014 Results

Call for Bids NL14-01 (Figure 21 adjacent) consisted of a single parcel of land in the Jeanne d'Arc Basin totaling 108,938 hectares.

Based upon the single work commitment criteria, the winning bid in the amount of CAD $16.7 million, was submitted by ExxonMobil Canada Ltd. 100%.

Figure 21 - NL14-01 Call for Bids



3.2.3 Call for Nominations 2014

In 2014 the C-NLOPB issued three Calls for Nominations:

- Call for Nominations NL14-01 JDA (Jeanne d'Arc Region) (Parcels);
- Call for Nominations NL14-01 EN (Eastern Newfoundland (Parcels);
- Call for Nominations NL14-01 Eastern Newfoundland (Areas of Interest).

Responses to the Calls for Nominations (Parcels) will assist the Board in selecting parcels to be included in the 2015 Call for Bids expected to be announced in the spring of 2015. A Call for Nominations (Areas of Interest) provides interested parties with the opportunity to nominate lands to be included in a Sector. This is then followed by a Call for Nominations (Parcels) within that Sector.

Parties interested in submitting for either or both Call for Nominations (Parcels) had until 4:00 p.m. on October 17, 2014 to submit responses. An announcement for the 2015 Call for Bids parcels is expected in the spring of 2015.

Parties interested in submitting for the Call for Nominations (Areas of Interest) had until 4:00 p.m. on November 28, 2014 to submit responses. The results of this Call for Nominations to identify the sectors is expected in the spring of 2015.

3.3 Exploration Program

3.3.1 Drilling Programs

Offshore Activity

Four new exploration wells were spud in the 2014.

Following up on its discoveries at Harpoon 0-85, Bay du Nord C-78 and Bay du Nord C-78Z wells in the Flemish Pass Basin in 2013 Statoil Canada, with co-venture partner Husky Energy, continued with their exploration drilling program in 2014. Utilizing the West Hercules semi-submersible drilling rig, three additional exploration wells were drilled in the Flemish Pass. They included Bay de Verde F-67, Bay de Verde F-67Z, and Bay du Nord P-78. No results have been released for each of these wells by the co-venture partners. Note that drilling results can remain confidential for two years after the well termination date.

Also in 2014 Husky Energy with co-venture partners Suncor Energy and Repsol used the Henry Goodrich drilling rig to drill the Aster C-93A exploration well in the southern portion of the Flemish Pass Basin. No drilling results for the well have been released by the co-venture partners.

Onshore Activity

Investcan Energy is the current permit holder of the onshore exploration permits in the Flat Bay area of Western Newfoundland. In 2012, the company announced that they would be pursuing a four well pilot appraisal program on the tight oil prospect in the area. The program consists of drilling three oil producers and one water injector. The first oil producer, Gobineau 1, was spud on November 31, 2012, on exploration permit EP 03-106 utilizing Junex's Foragaz 3 drilling rig. The well was completed in 2012 and no information on drilling results have been announced by the company. On June 28, 2013, Investcan Energy announced they were proceeding through the environmental review process for additional wells. Investcan subsequently downsized operations in advance of slumping oil prices and regulatory review processes.

3.3.2 Geoscience Programs

Offshore Activity

TGS-NOPEC Geophysical Company ASA (TGS) and Multi Klient Invest AS (MKI), a wholly owned subsidiary of Petroleum Geo-Services ASA (PGS), continued with their multi-year 2D seismic program in 2014 utilizing two vessels; Sanco Spirit and Atlantic Explorer.

The Sanco Spirit collected 21,854 line kilometers (km) of 2D seismic data on the northeast Newfoundland slope and the Atlantic Explorer collected 10,344 line km in the southern Grand Banks and 4,390 line km in southern Labrador. These programs have acquired over 80,000 line km,

Figure 22- Sanco Spirit in St. John's Harbour

Source: Department of Natural Resources

making it one of the largest, modern programs completed over a specific region.
The companies have announced that they will return in 2015 to continue with the multi-client 2D program and possibly expand into a multi-client 3D survey.

In the Flemish Pass/Orphan Basis Region there were two major programs conducted. Statoil utilized the 3D seismic ship WG Columbus to collect 3,186 km^2 and EMGS completed a 2,342 km controlled source electromagnetic survey (CSEM) survey, using the vessel the Boa Galatea.

Several minor programs were also completed throughout the offshore area. TGS completed a seafloor and seep sampling survey offshore Labrador collecting 2,705 km of data. In the Jeanne d'Arc Region, Husky Energy, ExxonMobil and Hibernia Management Development Corporation completed wellsite/seabed surveys for potential future drilling operations.

The total seismic data collected in 2014 is the highest amount collected since 1983.

Onshore Activity

In 2007, with the release of the Energy Plan, the provincial government announced a $5.0 million investment into the Petroleum Exploration Enhancement Program (PEEP). The goal of the program was to engage the geoscience community in an effort to advance onshore oil and gas exploration in western Newfoundland. In 2014 two geoscience programs were conducted with support from PEEP.

The first program titled: Detailed Compositional Analysis of Light hydrocarbons (C1-C4), Trace Elements and Soil Salts in Western Newfoundland, involved sampling soil in the Deer Lake and Bay St. George basins for geochemical analysis.

The second program titled: Petroleum System Analysis of Western Newfoundland, involved sampling of source rocks from the onshore portion of the Anticosti Basin for geochemical analyses.

It is expected that both of these projects will be extended and completed in 2015.

3.4 Regulatory Affairs

3.4.1 License/Permit Updates

There were six exploration licenses at the end of their respective terms during 2014 and the land was returned to crown reserve. They included:

1/ EL 1115—Southern Newfoundland Region

2/ EL 1097R—Western Newfoundland and Labrador Region

3/ EL 1111—Eastern Newfoundland Region

4/ ELs 1106, 1107 and 1108—Labrador South

3.4.2 Hydraulic Fracturing Moratorium Update

In November 2013, the Minister of Natural Resources announced that no applications for onshore and onshore-to-offshore petroleum exploration using hydraulic fracturing would be accepted until government could undertake a balanced review of regulations, rules and guidelines in other jurisdictions; complete the technical work necessary to fully assess the geological impact in Western Newfoundland; and following this process, undertake public consultations to ensure that residents can comment and are fully informed before any decisions relating to hydraulic fracturing are made.

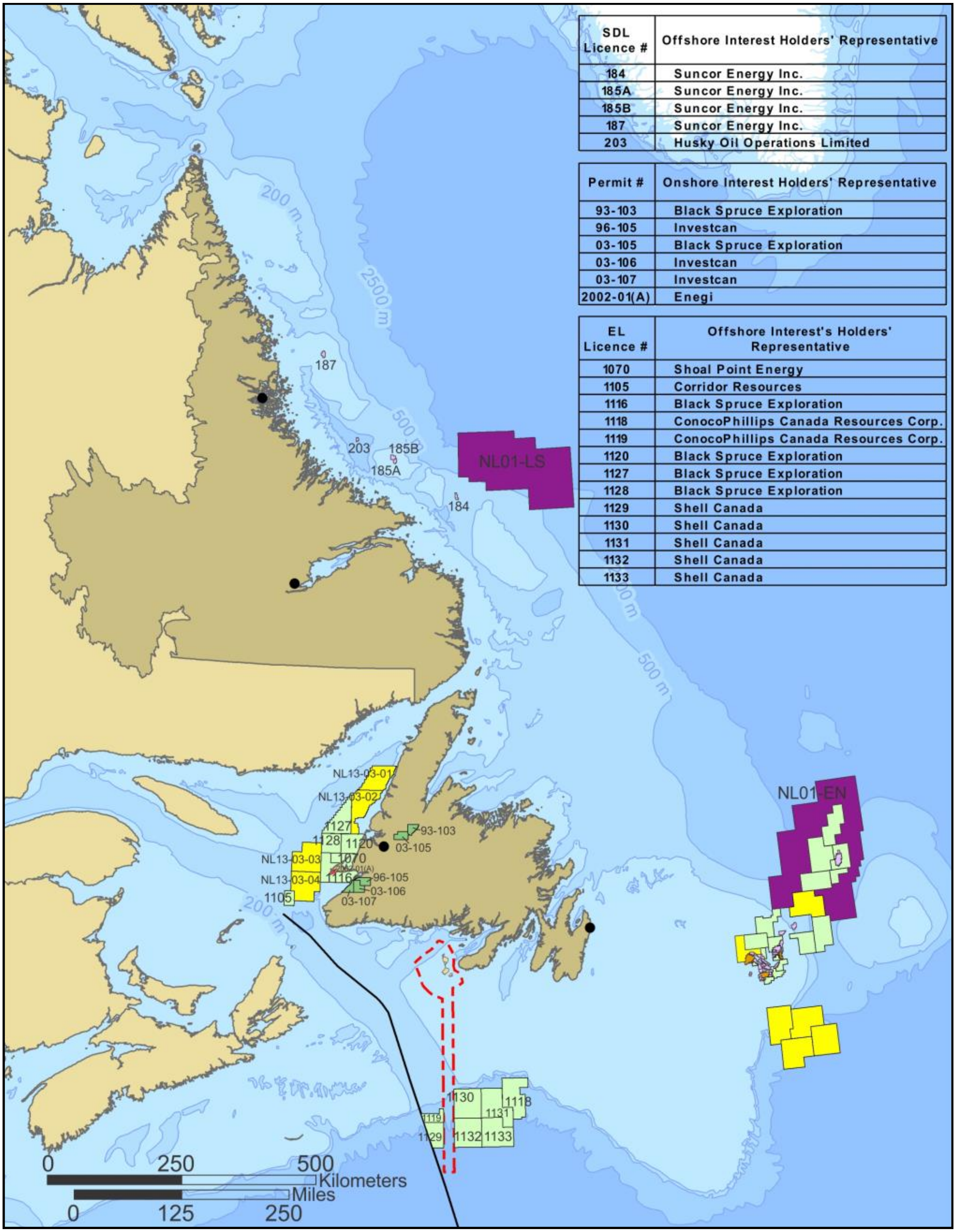
In October, 2014 a five member independent panel was appointed by the Minister of Natural Resources to conduct a public review and make recommendations on whether or not hydraulic fracturing should be undertaken in Western Newfoundland.

The mandate of the panel is to conduct a public review and advise the Minister of Natural Resources on the socio-economic and environmental implications of the hydraulic fracturing process with respect to the possible exploration and development of the petroleum resources of Western Newfoundland.

The regulatory context is the current framework for environmental assessment and monitoring and petroleum industry oversight. The work of the panel will involve gathering information through the following processes:

- Public consultations in Western Newfoundland, including community meetings;
- Internet/web-based consultations and written submissions;
- Stakeholder consultations, including meetings and written submissions;
- A review of regulatory processes related to hydraulic fracturing in other jurisdictions;
- An identification of environmental risks to water, land and communities respecting hydraulic fracturing operations;
- An identification of current best industry practices and procedures respecting hydraulic fracturing operations; and
- A review of current regulatory process in Newfoundland and Labrador respecting hydraulic fracturing operations and identifying needed changes consistent with other jurisdictions and best practices.

Appendix A - Licence Holders
Newfoundland South/West Coasts, and Labrador Region

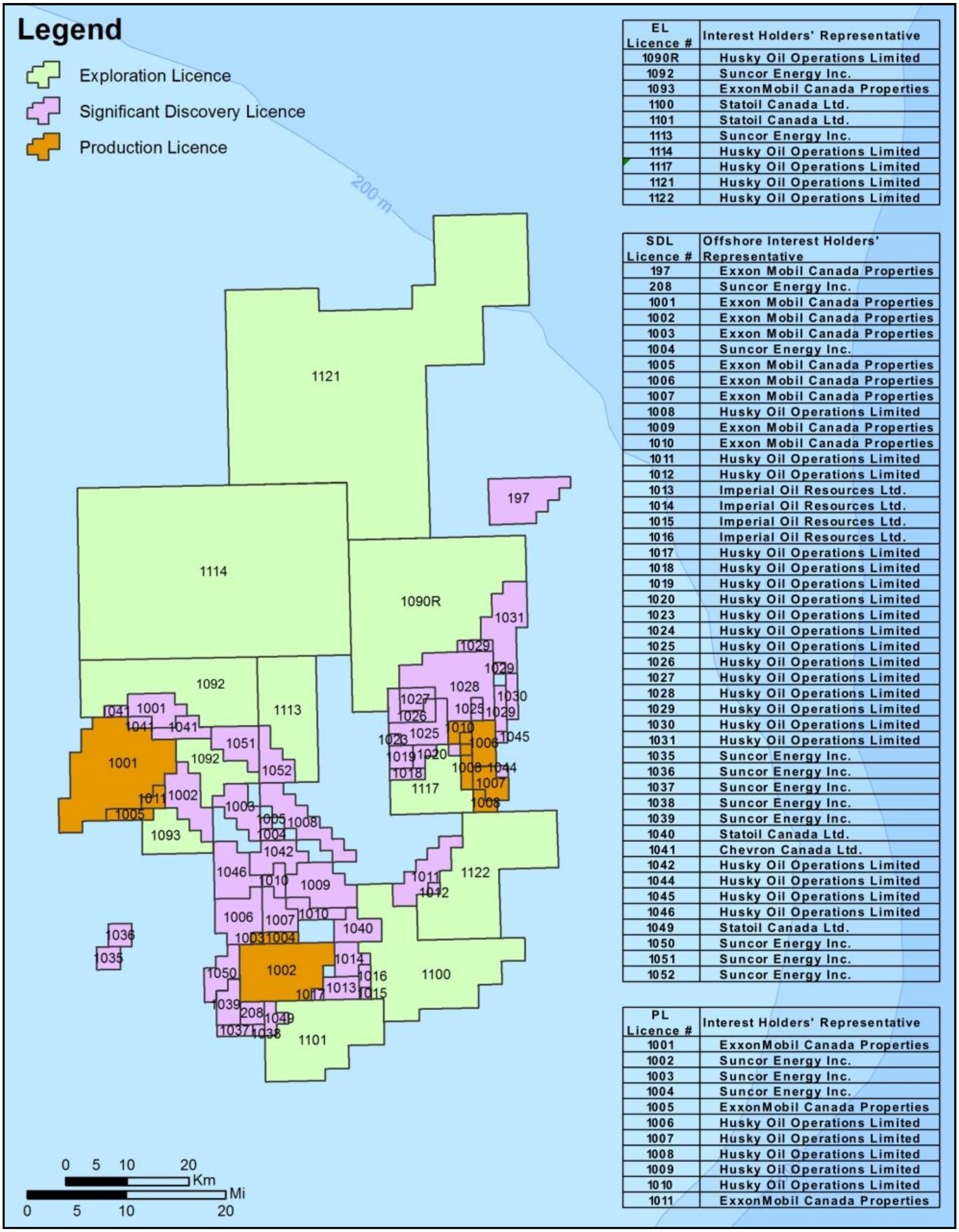


SDL Licence #	Offshore Interest Holders' Representative
184	Suncor Energy Inc.
185A	Suncor Energy Inc.
185B	Suncor Energy Inc.
187	Suncor Energy Inc.
203	Husky Oil Operations Limited

Permit #	Onshore Interest Holders' Representative
93-103	Black Spruce Exploration
96-105	Investcan
03-105	Black Spruce Exploration
03-106	Investcan
03-107	Investcan
2002-01(A)	Enegi

EL Licence #	Offshore Interest's Holders' Representative
1070	Shoal Point Energy
1105	Corridor Resources
1116	Black Spruce Exploration
1118	ConocoPhillips Canada Resources Corp.
1119	ConocoPhillips Canada Resources Corp.
1120	Black Spruce Exploration
1127	Black Spruce Exploration
1128	Black Spruce Exploration
1129	Shell Canada
1130	Shell Canada
1131	Shell Canada
1132	Shell Canada
1133	Shell Canada

Appendix B - Licence Holders
Jeanne d'Arc Basin Region

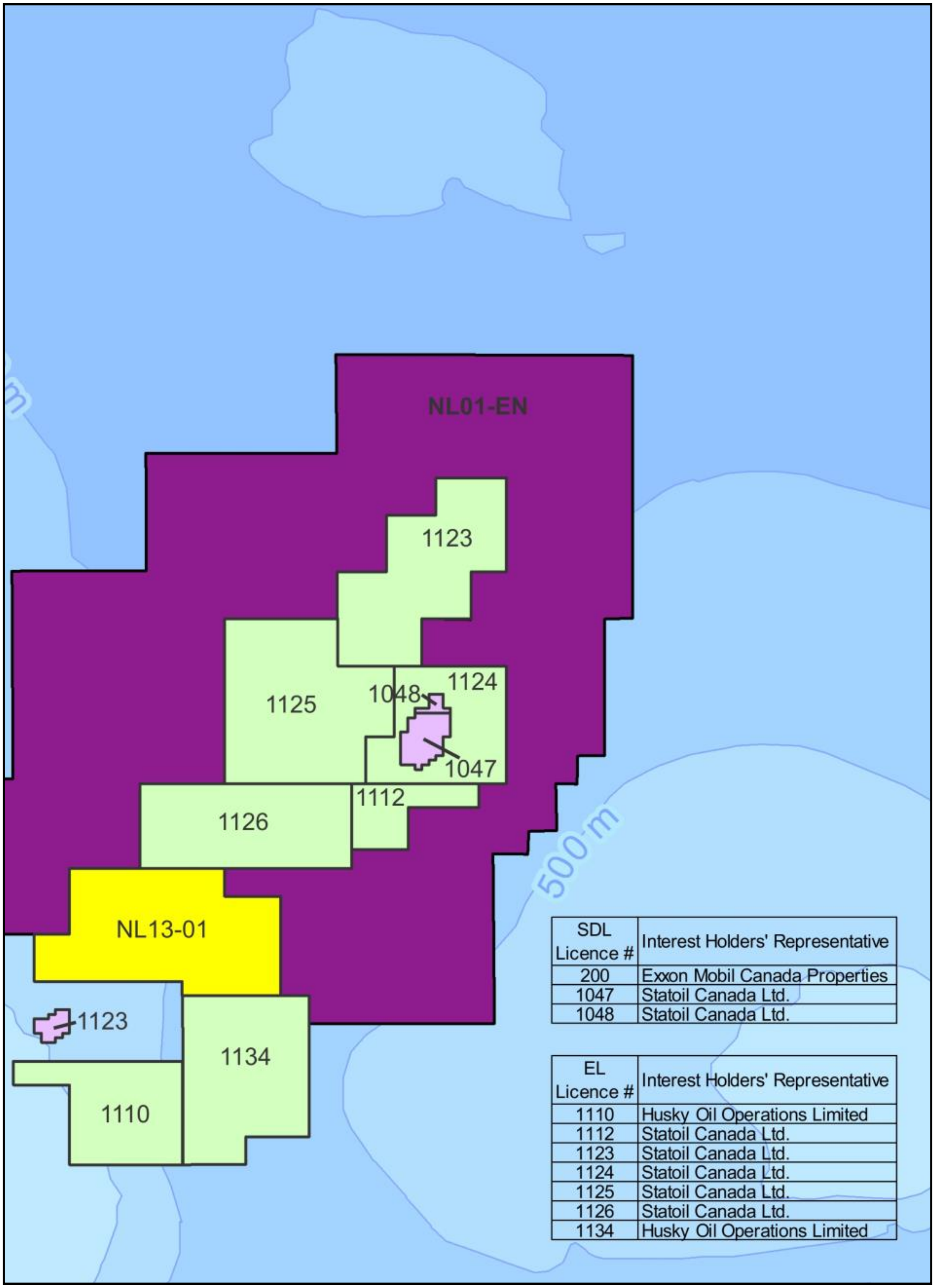


EL Licence #	Interest Holders' Representative
1090R	Husky Oil Operations Limited
1092	Suncor Energy Inc.
1093	ExxonMobil Canada Properties
1100	Statoil Canada Ltd.
1101	Statoil Canada Ltd.
1113	Suncor Energy Inc.
1114	Husky Oil Operations Limited
1117	Husky Oil Operations Limited
1121	Husky Oil Operations Limited
1122	Husky Oil Operations Limited

SDL Licence #	Offshore Interest Holders' Representative
197	Exxon Mobil Canada Properties
208	Suncor Energy Inc.
1001	Exxon Mobil Canada Properties
1002	Exxon Mobil Canada Properties
1003	Exxon Mobil Canada Properties
1004	Suncor Energy Inc.
1005	Exxon Mobil Canada Properties
1006	Exxon Mobil Canada Properties
1007	Exxon Mobil Canada Properties
1008	Husky Oil Operations Limited
1009	Exxon Mobil Canada Properties
1010	Exxon Mobil Canada Properties
1011	Husky Oil Operations Limited
1012	Husky Oil Operations Limited
1013	Imperial Oil Resources Ltd.
1014	Imperial Oil Resources Ltd.
1015	Imperial Oil Resources Ltd.
1016	Imperial Oil Resources Ltd.
1017	Husky Oil Operations Limited
1018	Husky Oil Operations Limited
1019	Husky Oil Operations Limited
1020	Husky Oil Operations Limited
1023	Husky Oil Operations Limited
1024	Husky Oil Operations Limited
1025	Husky Oil Operations Limited
1026	Husky Oil Operations Limited
1027	Husky Oil Operations Limited
1028	Husky Oil Operations Limited
1029	Husky Oil Operations Limited
1030	Husky Oil Operations Limited
1031	Husky Oil Operations Limited
1035	Suncor Energy Inc.
1036	Suncor Energy Inc.
1037	Suncor Energy Inc.
1038	Suncor Energy Inc.
1039	Suncor Energy Inc.
1040	Statoil Canada Ltd.
1041	Chevron Canada Ltd.
1042	Husky Oil Operations Limited
1044	Husky Oil Operations Limited
1045	Husky Oil Operations Limited
1046	Husky Oil Operations Limited
1049	Statoil Canada Ltd.
1050	Suncor Energy Inc.
1051	Suncor Energy Inc.
1052	Suncor Energy Inc.

PL Licence #	Interest Holders' Representative
1001	ExxonMobil Canada Properties
1002	Suncor Energy Inc.
1003	Suncor Energy Inc.
1004	Suncor Energy Inc.
1005	ExxonMobil Canada Properties
1006	Husky Oil Operations Limited
1007	Husky Oil Operations Limited
1008	Husky Oil Operations Limited
1009	Husky Oil Operations Limited
1010	Husky Oil Operations Limited
1011	ExxonMobil Canada Properties

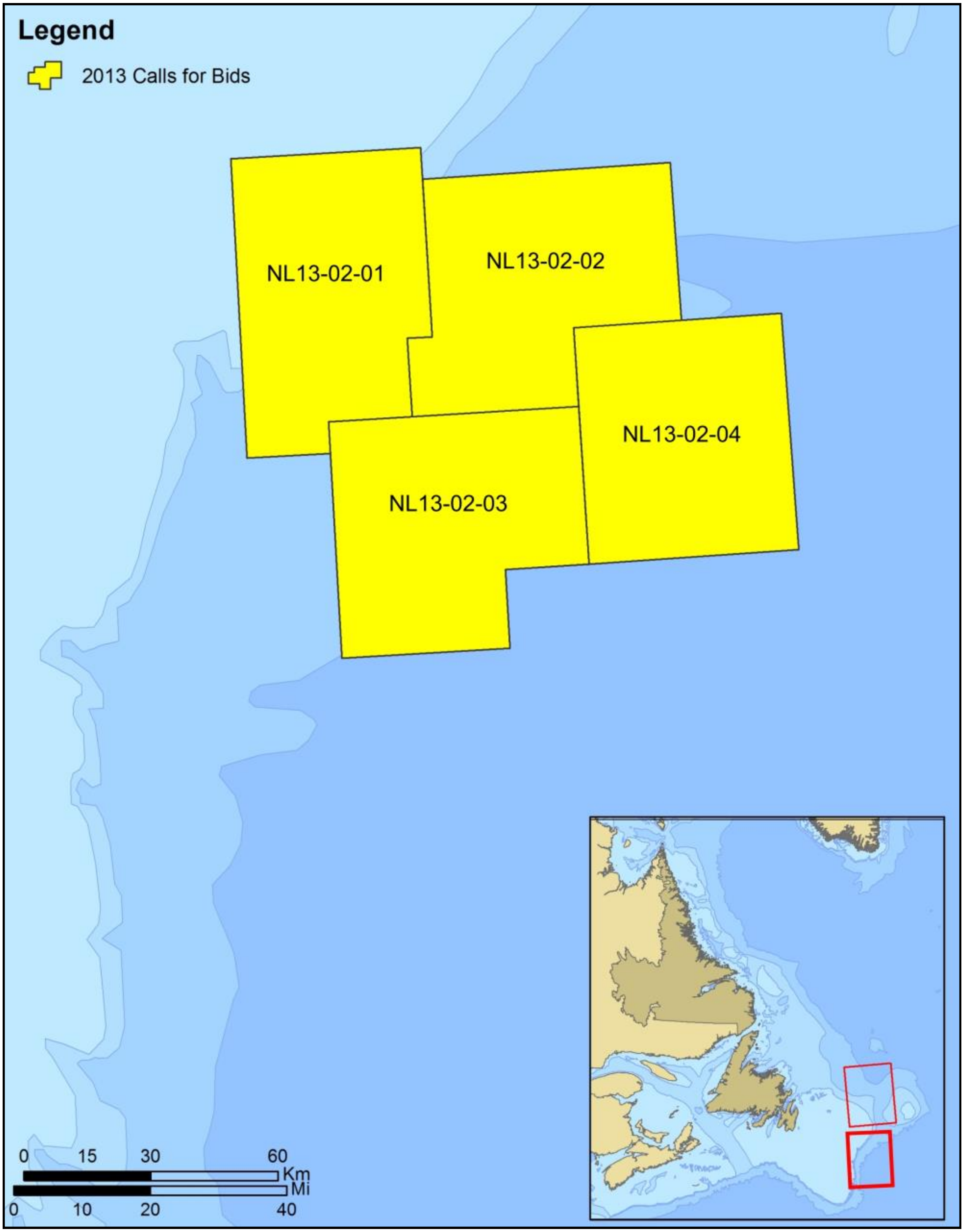
Appendix C - Licence Holders
Flemish Pass Basin Region

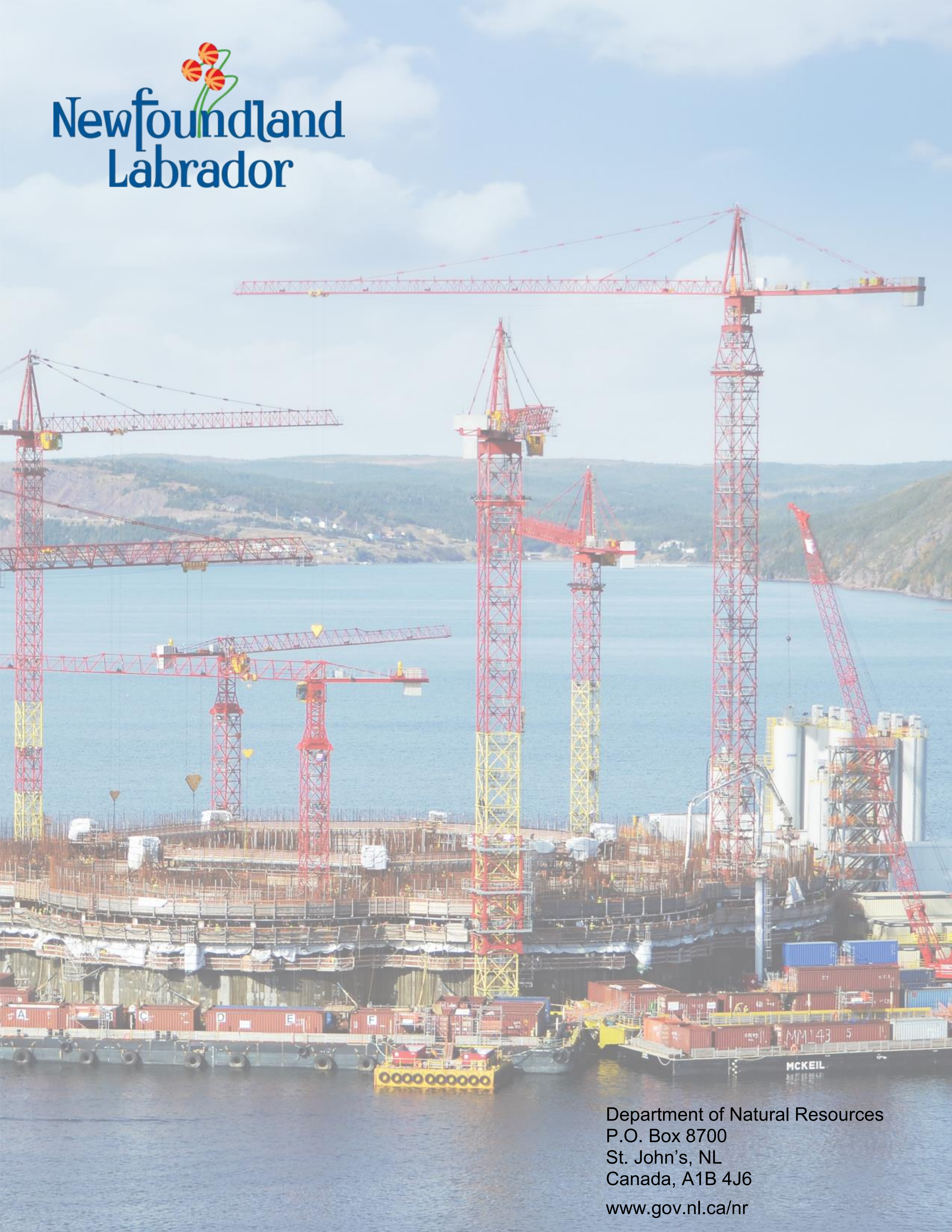


SDL Licence #	Interest Holders' Representative
200	Exxon Mobil Canada Properties
1047	Statoil Canada Ltd.
1048	Statoil Canada Ltd.

EL Licence #	Interest Holders' Representative
1110	Husky Oil Operations Limited
1112	Statoil Canada Ltd.
1123	Statoil Canada Ltd.
1124	Statoil Canada Ltd.
1125	Statoil Canada Ltd.
1126	Statoil Canada Ltd.
1134	Husky Oil Operations Limited

Appendix D - Licence Holders
Carson Basin Region





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