2015

Newfoundland Labrador

Petroleum Development - Activity Report

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Department of Natural Resources
Petroleum Development
Activity Report - 2015

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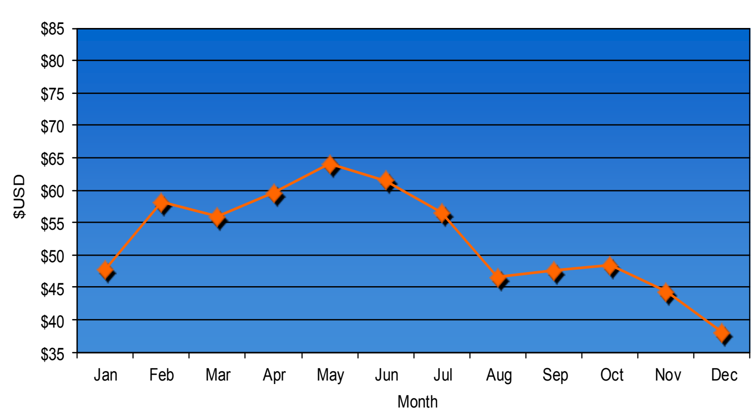
1.0 Introduction

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. First oil production in Newfoundland and Labrador occurred on Nov 17th, 1997 from the Hibernia Field and at the end of 2015, cumulative oil production from Newfoundland & Labrador's four offshore producing projects, was approximately 1.59 billion barrels. This represented approximately 8% of Canada's crude oil output over that time and nearly 27% of its conventional light crude oil production.

While production levels and market prices have been decreasing, the oil industry continues to be a significant contributor to the provincial economy. Natural production declines are occurring at all producing fields (See Section 2.0 Field Development Overviews) and the dramatic drop in oil prices has seriously eroded the overall value of oil production (see figure 1). However, the industry continues to be a major contributor to the provincial economy. Oil royalties account for nearly 23% of provincial revenue while employing approximately 8,400 people, or 3.6% of total employment.

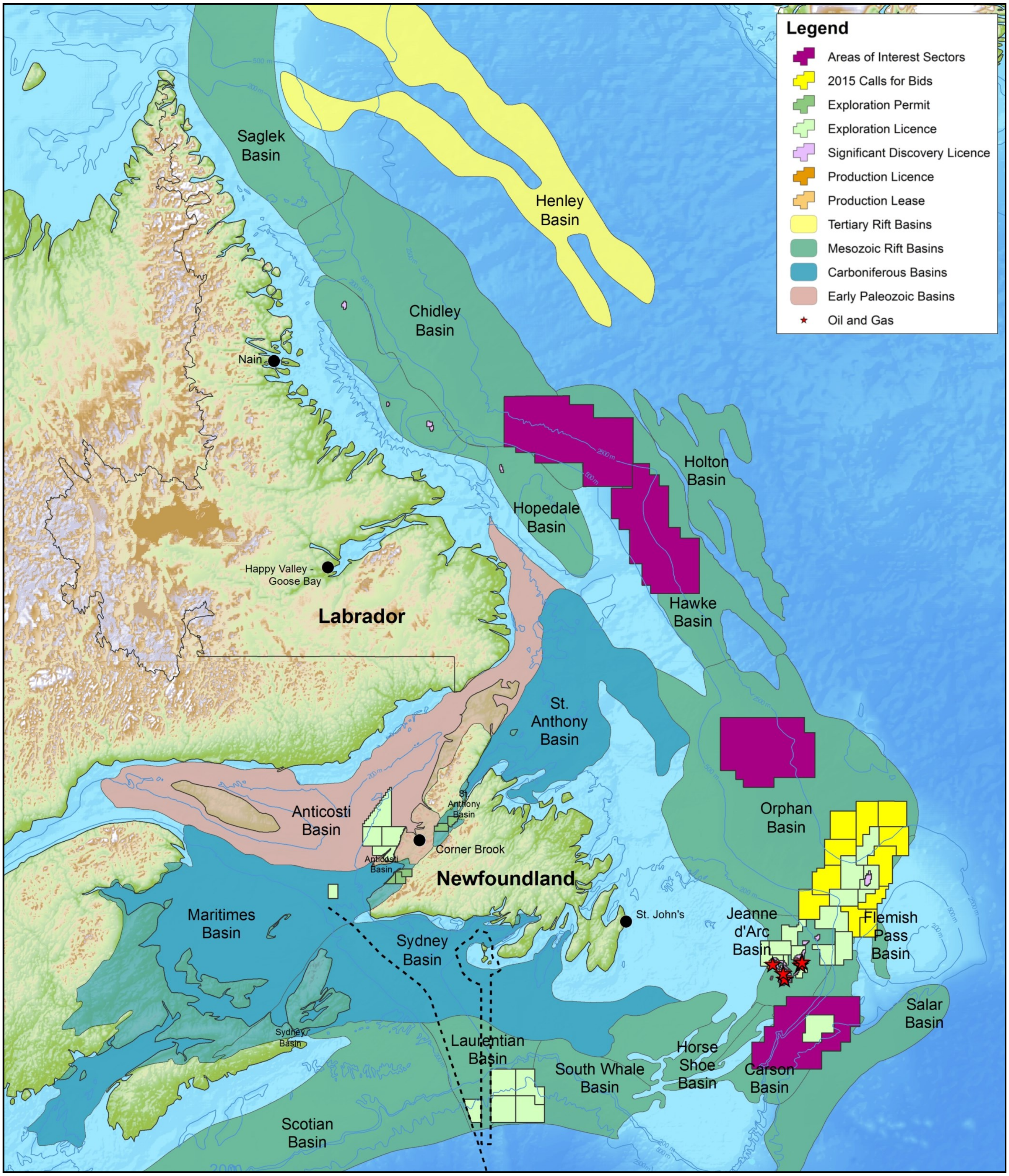
Figure 1 - Weekly Europe Brent Spot Price FOB 2015 (Dollars per Barrel)



Source: U.S. Energy Information Administration

Currently Newfoundland and Labrador has 3% 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 180 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



Source: Department of Natural Resources

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, 2015, the C-NLOPB had issued 24 exploration licences, 55 significant discovery licences and 11 production licences (See Appendices A - C). There have been a total of 421 wells spud in the province's offshore area as of December 31, 2015. They are comprised of 202 development wells, 56 delineation wells and 163 exploration wells. The exploration and delineation wells have resulted in 55 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 3.9 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, 2015 the province had five exploration permits and one production lease on record. The exploration permits onshore, encompassing approximately 181,078 hectares, have been issued in two general areas in western Newfoundland: Flat Bay and Deer Lake. The production lease totaling 1,957 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 2015.

Table 1 - Reserves and Resources

Petroleum Reserves[1] and Resources[2] Newfoundland Offshore Area (Updated July 27, 2015)						
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	261.5	1644				
Hebron	112.4	707				
Terra Nova	80.5	506				
Whiterose[4]	64.2	404				
North Amethyst	11.9	75				
Resources						
Hibernia			66.3	2353	35.8	**225**
Terra Nova	3.5	22	1.8	64	0.7	**5**
Whiterose[5]	3.4	22	85.5	3018	14.6	**92**
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	**621.3**	**3909**	**235.1**	**8322**	**63**	**397**
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	**621.3**	**3909**	**354.7**	**12566**	**82.9**	**520**
Produced[6]	**246.8**	**1552**	**0**	**0**	**0**	**0**
Remaining	**374.5**	**2357**	**354.7**	**12566**	**82.9**	**520**

[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, the West White Pool and the North Avalon Pool
[5] White Rose Resources contains the Hibernia Reservoir.
[6] Produced reserve oil volumes as of May 31, 2015. Theses 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

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 transshipment facility at Whiffen Head, Placentia Bay, NL.

Figure 3 - Hibernia Platform

To date production from the Hibernia field 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.

Early production from Hibernia wells set Canadian daily flow records. The Hibernia B-16-1 well recorded a daily flow rate record when it tested at 56,000 barrels of oil per day back in 1998.The previous record of 27,000 barrels of oil per day was held by the Panuke Field offshore Nova Scotia.

As of December 31, 2015, Hibernia was operating with 65 development wells comprised of 38 oil producers, 22 water injectors, and five gas injectors. Hibernia produced 33.04 million barrels of oil during 2015 for an average daily production of 90,517 barrels. Cumulative oil production to December 31, 2015, was 951.7 million barrels representing 57.9% of the total current reserve estimate.

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%

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.

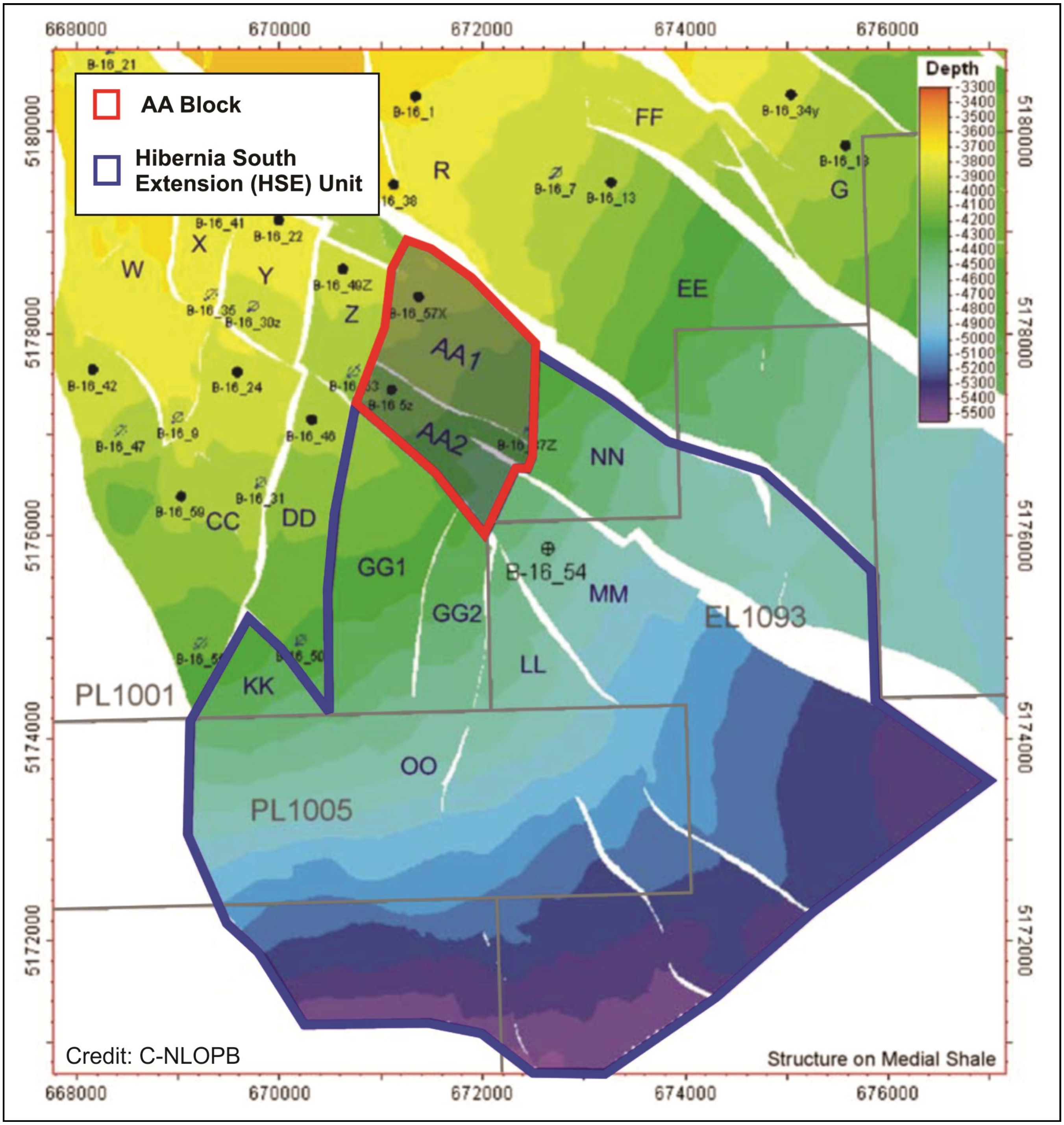
In 2015 production from the AA Block totaled 2.59 million barrels equating to an average daily production of 7,096 bopd. As at December 31, 2015 total cumulative production totaled 39.3 million barrels of oil representing 77% of its total current reserve estimate.

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 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

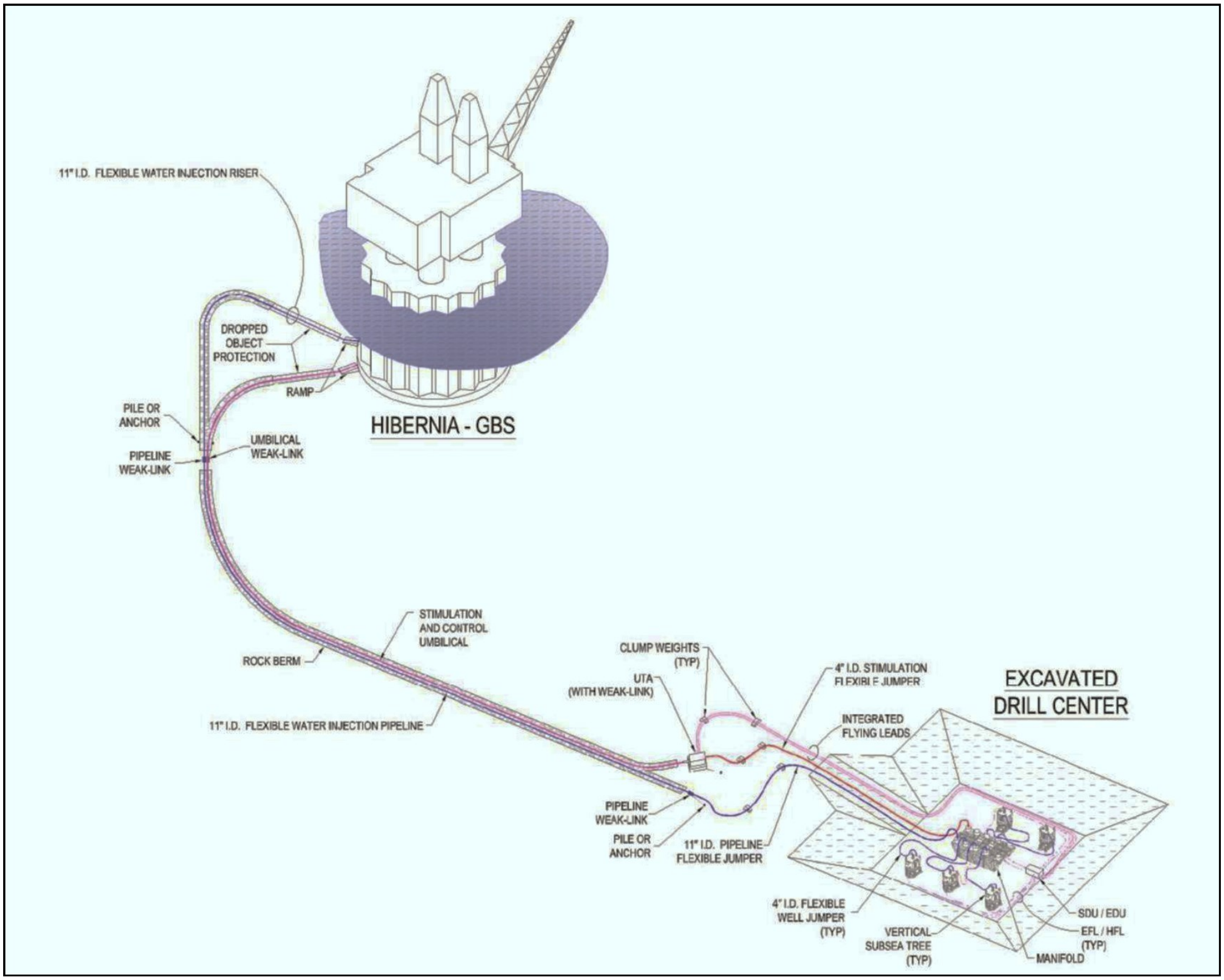
HSE Project Participants	EL 1093	PL 1005	PL 1011	Unitization
ExxonMobil Canada	29.8125%	22.5%	29.8125%	27.4 %
Chevron Canada Resources	24.1875%	22.5%	24.1875%	23.6 %
Petro-Canada Hibernia Partnership	18%	22.5%	18%	19.5 %
Statoil Canada Ltd.	4.5%	22.5%	4.5%	10.5 %
Nalcor Energy	10%	10%	10%	10 %
Canada 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 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 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 to house the subsea templates and manifolds for the water injection wells, which is located approximately seven kilometers southeast of the Hibernia GBS, was completed in 2012 (Figure 5, page 10).

Platform related tie-ins and commissioning of flowlines, jumpers, and subsea equipment for water injection occurred in 2014. 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 was brought on-line in 2014 and another oil producer, well B-16-64, was brought on-line in November 2015. Water injection well drilling continued in 2015 with the completion of the water injector P-02 2Z and the spudding of water injector P-02 4 by the West Aquarius drilling rig.

Figure 5 - Hibernia Southern Extension Development



Source: Stantec 2012 Environmental Assessment Review

Oil production during 2015 totaled 1.7 million barrels giving an average daily production of 4,697 bopd. Total cumulative production to December 31, 2015, was 6.5 million barrels of oil which represents approximately 3.3% 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 and is located 35 kilometers southeast of Hibernia, in about 90 meters of water. The discovery well, Terra Nova K-08 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 (Figure 6, page 13) 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.

The latest recoverable reserve/resource estimate for the Terra Nova field, released in April 2013, includes 506 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 currently forecast to stay into production until 2027.

Production at the Terra Nova Field in 2015 was affected by a planned ten week maintenance shutdown that occurred in May. Repairs were made to the crude oil storage tanks, replacement of the flare tip and a major inspection of the starboard main power generator. The shutdown was completed ahead of schedule and production resumed in early July, 2015.

Figure 6 - Terra Nova FPSO in Marystown

Source: Department of Natural Resources

At December 31, 2015, Terra Nova was operating with a total of 30 development wells, consisting of 17 oil producers, 10 water injectors, and three gas injectors. Total field production for 2015 was 13.06 million barrels of oil which equates to an annualized production of 35,781 bopd. Cumulative field production to the end of 2015 was 379.2 million barrels of oil which represents 75% of the current recoverable reserve estimate.

Suncor Energy, operators of the field, announced in 2015 that they are working on plans to enhance oil recovery and believe that there is more oil in the field than current reserves reflect. Improvements in both of these areas could extend the life of field development.

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 southeast 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 (See Figure 7 below), 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.

In July, 2015, the C-NLOPB increased the recoverable reserve/resource estimates for the field to 404 million barrels of oil, 3.02 trillion cubic feet of natural gas, and 96 million barrels of natural gas liquids. This increase added an additional 165 million barrels of oil to the reserve total.

Table 5 - White Rose Project Ownership

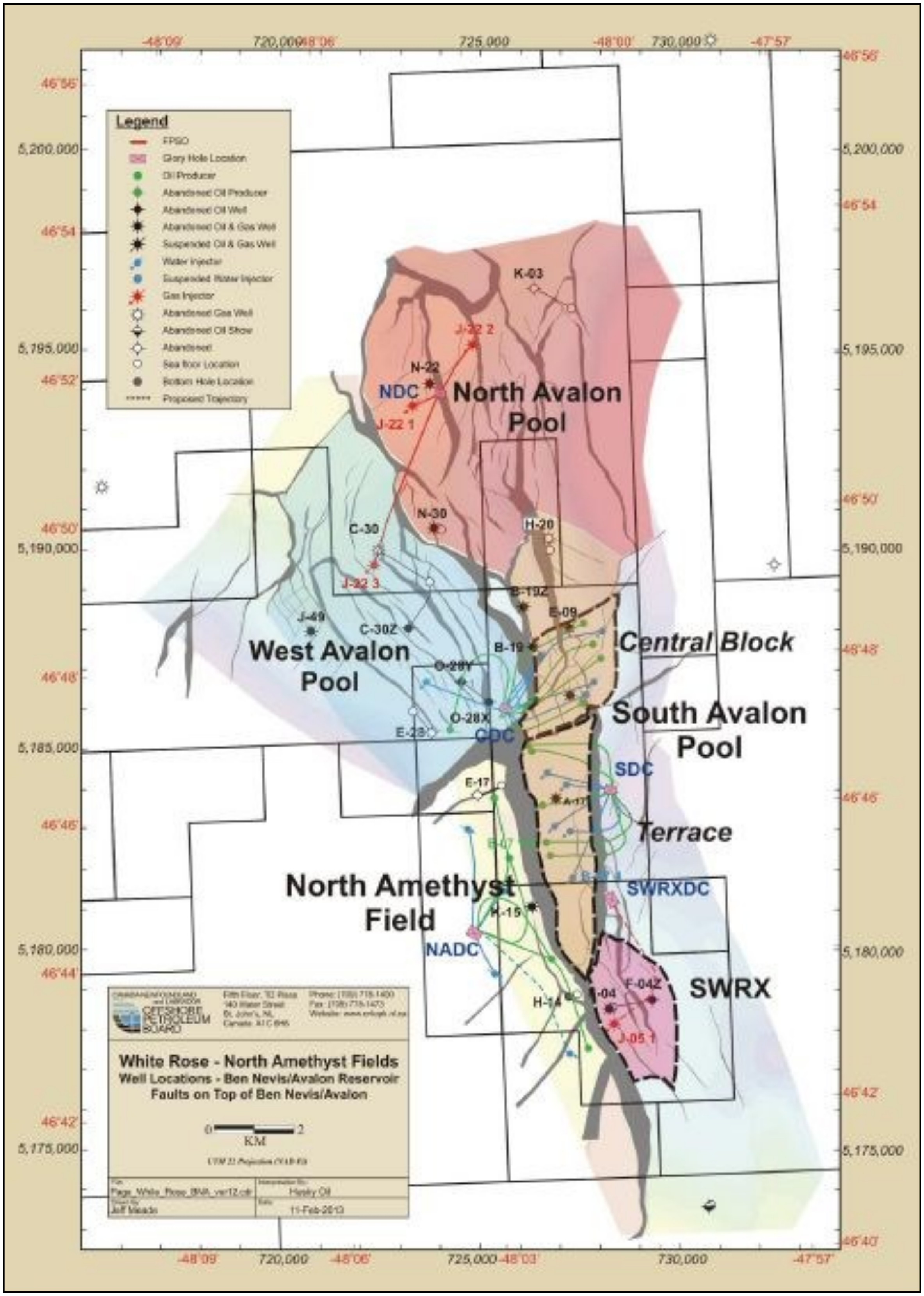
White Rose Project Ownership	
Husky Energy	72.5%
Suncor	27.5%

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 8, 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 tieback.

Figure 7 - White Rose FPSO - Sea Rose

Source: Department of Natural Resources

Figure 8 - White Rose Development Area



Source: C-NLOPB

Oil production in 2015 from the main White Rose field and the West White Rose pilot program discussed in section 2.3.1 totaled 12.9 million barrels of oil, which equates to an annualized daily production of 35,342 bopd. Total cumulative production as of December 31, 2015, was 211.3 million barrels, which represents 52.3% of the total reserve estimate. The main field and the West White Rose pilot program are being developed utilizing 27 development wells, consisting of 12 oil producers, 11 water injectors, and four 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 extension 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.

In 2015 it was announced that Seadrill cancelled the contract for the semi-submersible drilling rig, West Mira. The rig was scheduled to come to Newfoundland and Labrador to drill wells for Husky Energy at the White Rose field. In December 2015, Husky Energy announced that a contract was signed with Transocean to bring back the Henry Goodrich drilling rig (Figure 9 below) under a two year drilling contract.

Figure 9 - The Henry Goodrich

Source: Department of Natural Resources

2.3.1 West White Rose Extension

Development of the West White Rose portion of the field (re: West Avalon Pool see Figure 8, 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 2015, West White Rose produced 2.36 million barrels of oil raising total cumulative production at the pilot project to 11.1 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 of the well pair and analysis of the results of the 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. 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. In 2015, Husky announced that they were continuing with the design work to minimize later design changes and more accurately estimate construction costs and scheduling. Work on the graving dock was completed in March, 2015 and no further construction has taken place at the Argentia site.

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.

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 new 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 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.

With the new reserve/resource estimate released in July 2015, it is now 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 nine million barrels of oil from the South Avalon Terrace area of the main field. Note that these reserve estimates are also included in the total reserve/resource estimate for White Rose as detailed in Section 2.3

Work began on the project 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. The first SWRX producer, J-05 3, came on-line in June of 2015 which was followed by the South Avalon Terrace producer J-05 2 which came on-line in September 2015. The total production from the oil producers was 1.13 million barrels in 2015 with no water injection support.

2.4 North Amethyst Field

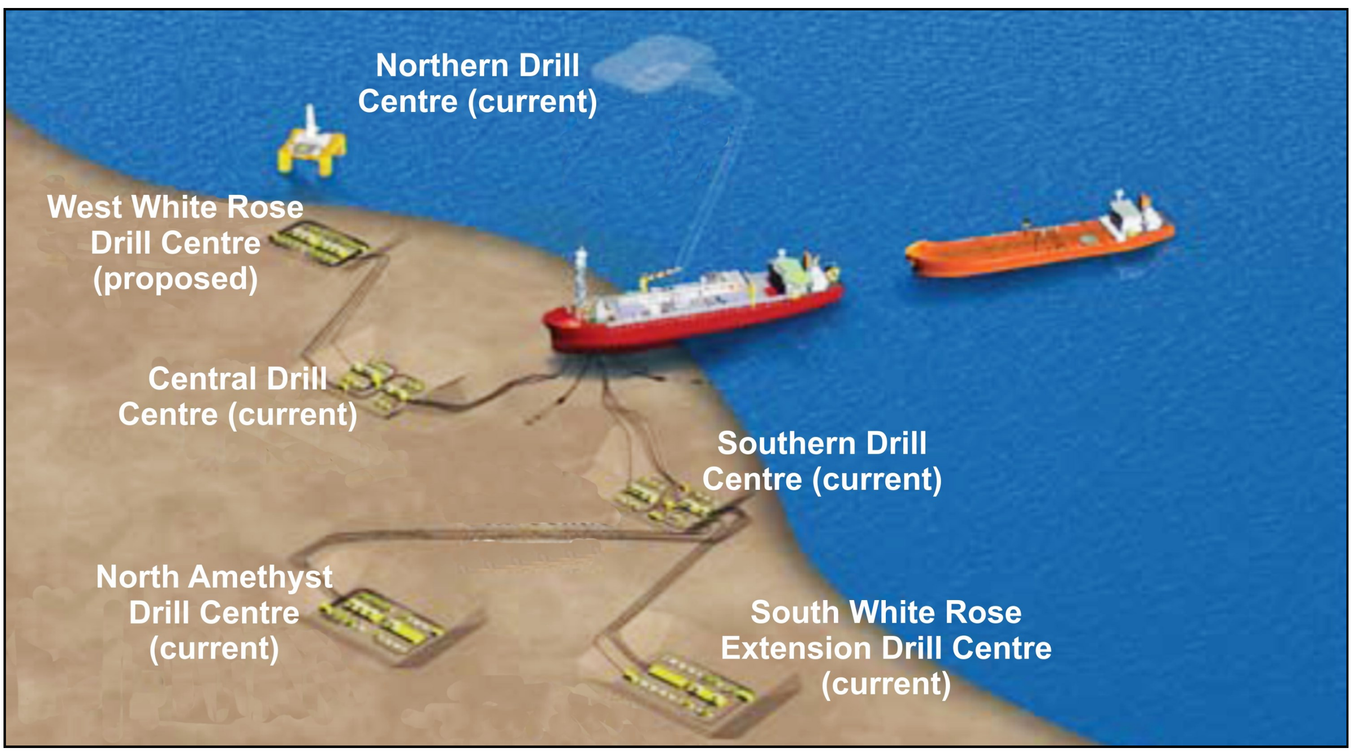
The North Amethyst field was the first of the satellite pools to be developed in the Jeanne d'Arc Basin. Figure 10 below shows the location of the North Amethyst field relative to the White Rose project area. It was identified by exploratory drilling in 2006 and the C-NLOPB reported recoverable reserve/resource estimates of 75 million barrels of oil and 315 billion cubic feet of natural gas in the Ben Nevis/Avalon and Hibernia formations.

Table 6 - North Amethyst Project Ownership

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

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 10 - White Rose Tie Back Development via SeaRose FPSO



Source: Husky Energy

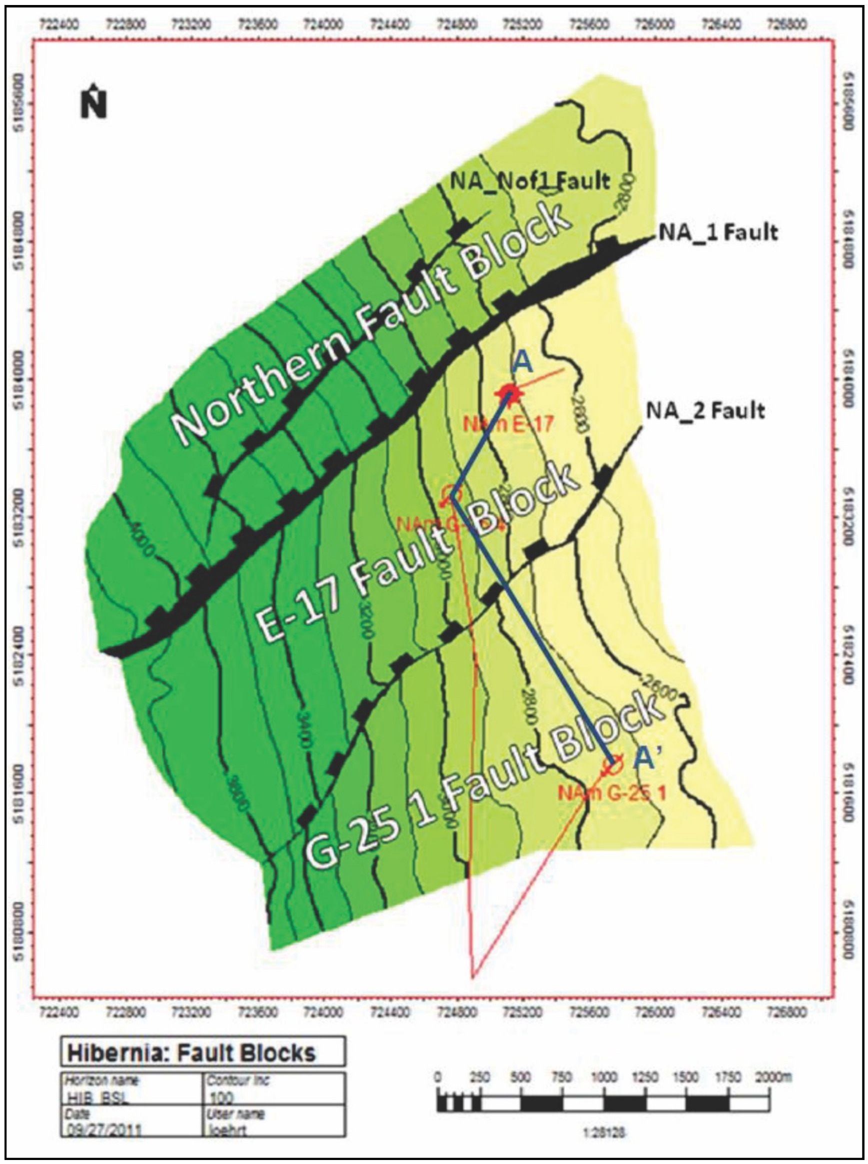
2015

As of December 31, 2015, North Amethyst was operating with nine development wells, consisting of five oil producers and four water injectors. Total oil production in 2015 was 3.66 million barrels of oil for an average production of 10,022 bopd. Cumulative production to December 31, 2015, was 43.1 million barrels representing 57.5% 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 11 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 last well spud for North Amethyst was E-18 12Z in August 2014. No development wells were spud in 2015 in the field.

Figure 11 - North Amethyst Hibernia fault blocks and well locations



Source: Husky Energy

2.5 Hebron/Ben Nevis Field

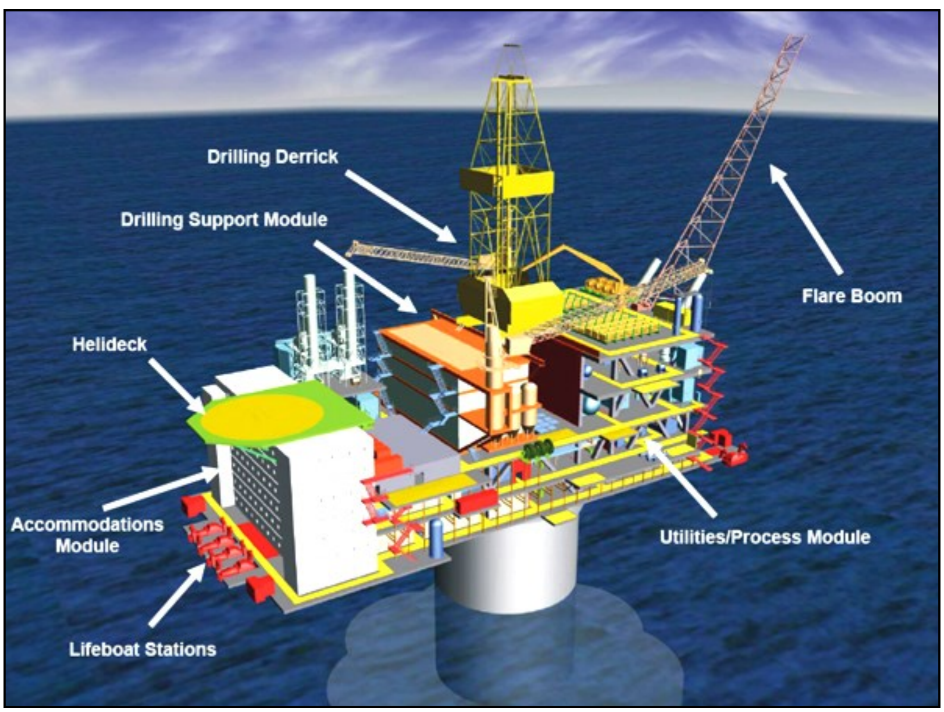
The Hebron field was discovered in 1981 when the Mobil et al Hebron I-13 discovery well recovered hydrocarbons from five intervals with a combined flow rate of 9,070 barrels of oil per day. The field is located in the Jeanne d'Arc Basin, approximately 32 kilometers southeast of Hibernia, 9 kilometers 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 .

Table 7 - Hebron Project Ownership

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

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 12 - Proposed Hebron Development



Source: ExxonMobil

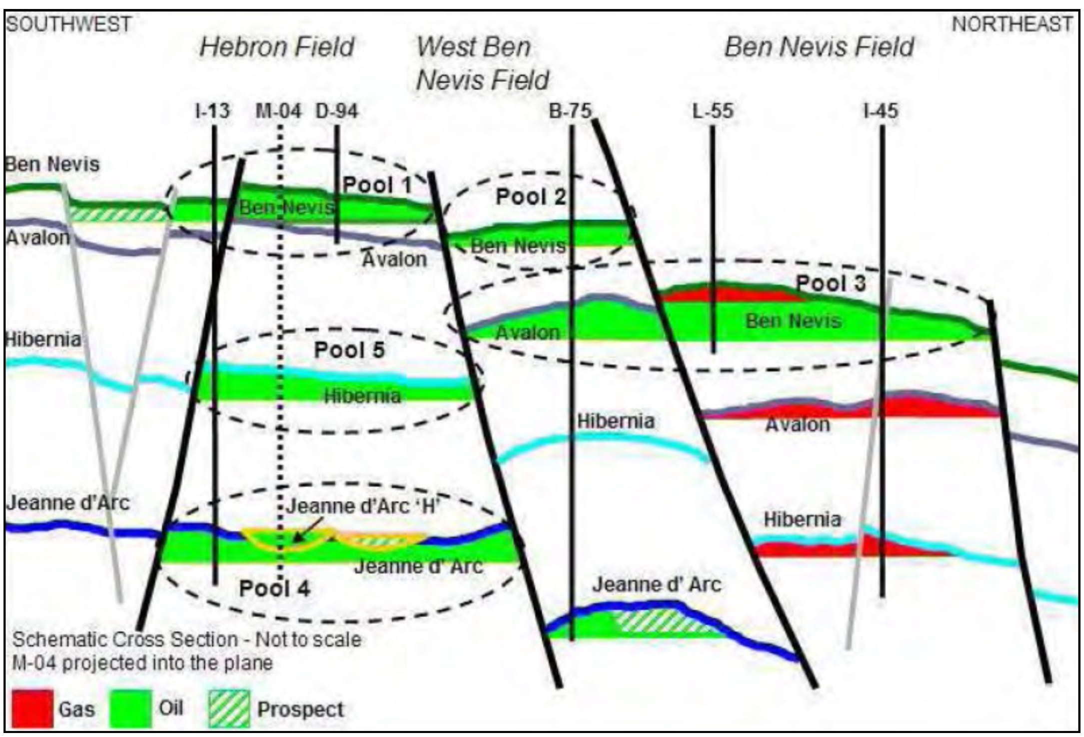
Formal agreements were signed with the co-venture partners and the Government of Newfoundland and Labrador to develop the Hebron offshore project on August 20, 2008. As part of the agreement, Nalcor Energy - Oil and Gas purchased a 4.9% stake in the project at a cost of $110 million CAD. It was also 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 13 below. The main Hebron field includes pool 1 followed in a vertically stacked arrangement by pools 5 and 4 respectively.

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.

Figure 13 - Schematic cross-section across the Hebron Asset area



Source: ExxonMobil

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. 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. In 2015 work continued inside the GBS structure with mechanical outfitting and ballast support.

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 12 on page 21).

During late 2015 a number of topsides components were completed and moved to the Bull Arm site. In October, the Flare Boom was completed in Port aux Basques, NL by Talon Energy Services; the DES, fabricated by Hyundai Heavy Industries in Korea, arrived at Bull Arm site in November; and, in December the DSM was completed at the Kiewit Offshore Services facility in Marystown (See Figure 14 on page 24).

Scheduled for completion in 2016 are the Utilities Process Module (UPM), Living Quarters (LQ), helideck and life boat stations. The UPM is being constructed in Korea by Hyundai Heavy Industries, the LQ is being fabricated by NEAL (a partnership of North Eastern Constructors Limited and Apply Leirvik) at multiple sites throughout the Province including Bull Arm, Torbay and Argentia; and, fabrication of the helideck and life-boat stations is being performed by C & W Offshore at facilities in Port aux Basques and Bay Bulls, NL.

In late 2016, following completion of all topsides components and their arrival at the Bull Arm site, they will be integrated to form the completed Hebron topsides. The topsides will then be mated to the GBS for final hook up and commissioning. The platform is scheduled to be towed to the Grand Banks, NL early to mid 2017. The platform is designed for maximum production of 150,000 barrels of oil per day with a 30 year lifespan.

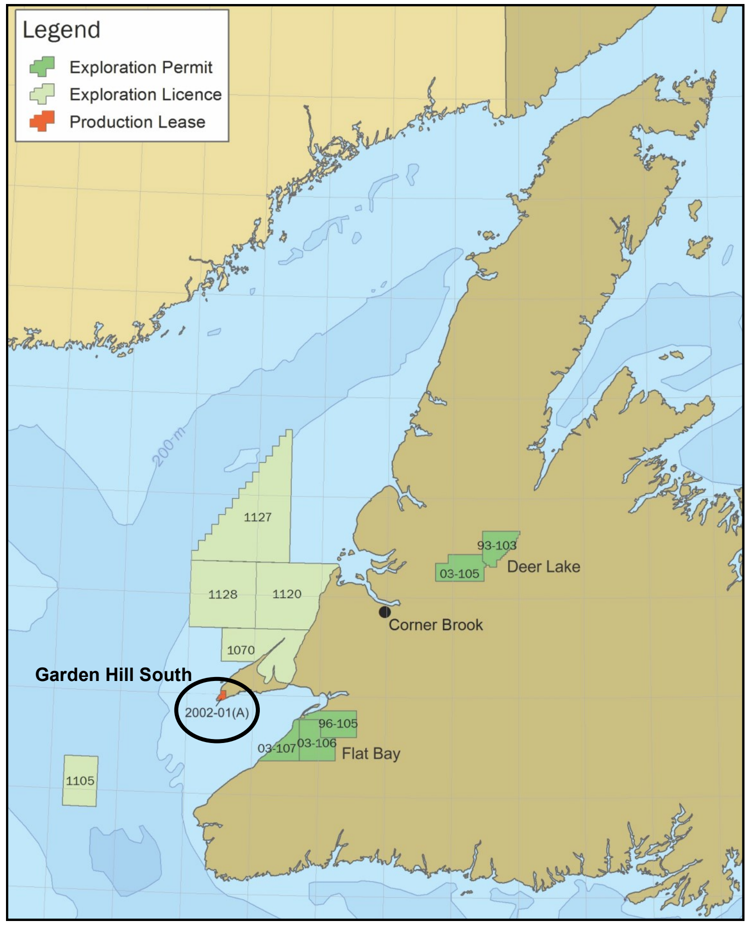
Figure 14 - Drilling Support Module for the Hebron project being fabricated at Marystown

Source: Department of Natural Resources

2.6 Garden Hill South Field

Garden Hill South is located onshore western Newfoundland on the Port au Port Peninsula (see Figure 15, 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 15 - 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 2015 there was minimal activity at the site as Enegi Oil cancelled the farm-in agreement late in December with Black Spruce Exploration and announced that they would be developing an incremental work program that provides the most appropriate route to further prove reserves to develop the area.

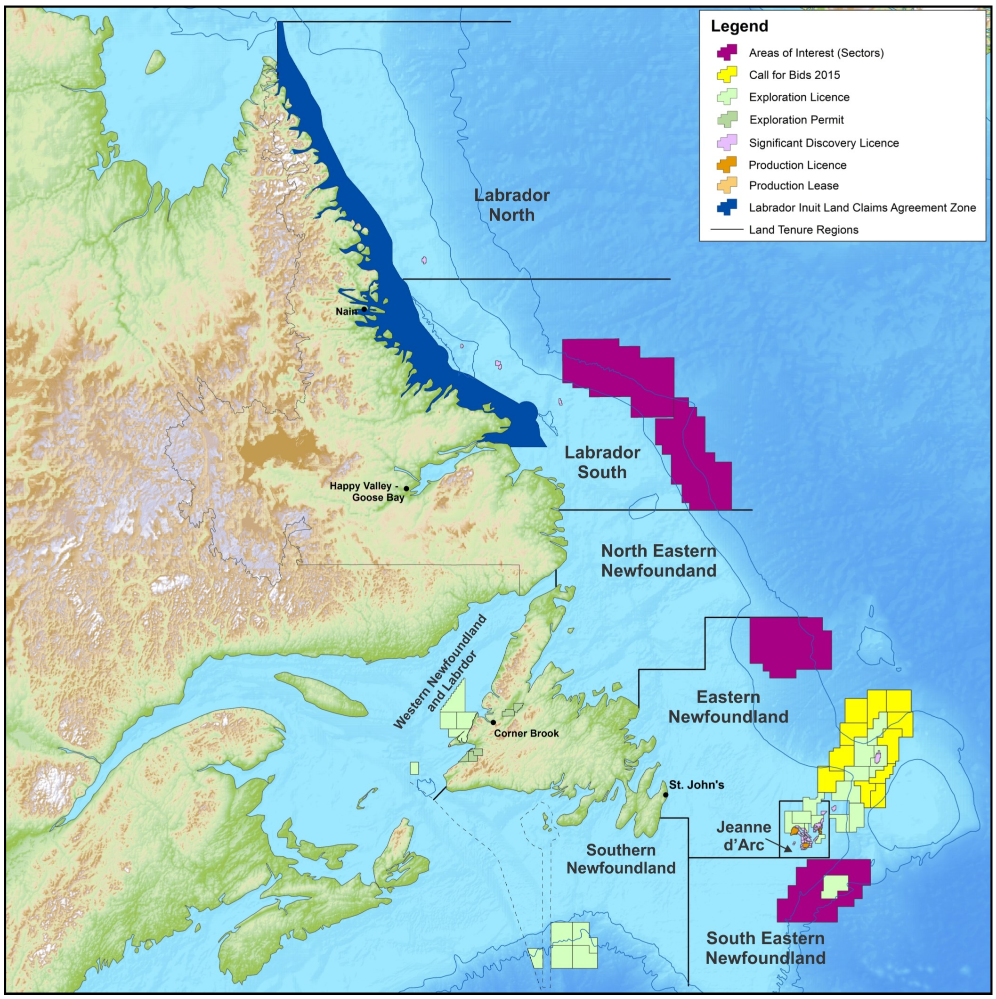
3.0 Regional Activity Overview

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 16, 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. Depending on exploration, delineation and development activity, regions may change designation over time.

Figure 16 - Scheduled Land Tenure Regions



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

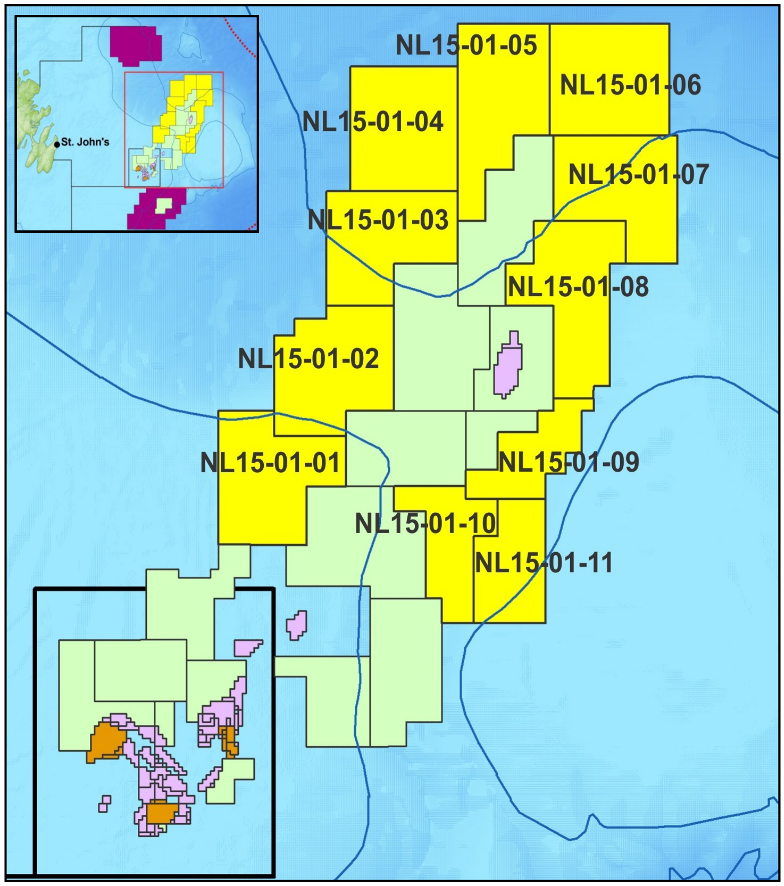
3.2.1 Calls for Bids 2015 Results

Call for Bids NL15-01 (Figure 17, page 28) closed on November 12, 2015 and consisted of eleven parcels of land totaling 2,581,655 hectares in the Flemish Pass Basin. An independent resource assessment completed by Beicep Franlab covering the Call for Bids license area identified “in place” potential of 12 billion barrels of oil and 113 trillion cubic feet of gas.

Overall, nine companies participated with a total of 13 bids submitted. Seven parcels were awarded with a total value of bids in excess of $1.2 billion in work commitments. The breakdown of successful bidders can be found in Table 8, page 29. This is the largest value of bids ever received in the Province for a licensing round. It also included three new explorers (Nexen Energy, BG International Limited and BP Canada Energy Group) who currently have no working interest in existing exploration licenses.

Note that Exploration Licenses will be issued to the successful bidders early in 2016 when all terms and conditions are met.

Figure 17 - NL15-01 Call for Bids



3.2.2 Land Tenure Activity

In 2015 the following activity occurred within various land tenure regions around the province.

1/ NL15-01JDA- Call for Nominations (Parcels) Jeanne d'Arc Basin closed for upcoming 2016 licensing round.

2/ NL15-01EN- Call for Nominations (Parcels) West Orphan Basin closed for upcoming 2016 licensing round.

3/ NL01-SEN- Announcement of the results of the Call for Nominations (Area of Interest) in the South Eastern Region (Carson Basin) for upcoming 2019 licensing round.

4/ NL02-LS- Announcement of the results of the Call for Nominations (Area of Interest) in the Labrador South Region (Hawke Basin) for the upcoming 2019 licensing round.

5/ NL02-EN- Announcement of Sector Identification for the Eastern Newfoundland Region which could lead to 2017 licensing round.

Table 8 - NL15-01 Call for Bids Results

PARCEL	HECTARES	SUCCESSFUL BIDDER	SUCCESSFUL BID AMOUNT
NL15-01-01	269 024	NA	**NA**
NL15-01-02	274 732	Chevron Canada Limited 35% Statoil Canada Ltd. 35%	**$43,175,000**
NL15-01-03	248 878	NA	**NA**
NL15-01-04	264 249	NA	**NA**
NL15-01-05	267 403	Statoil Canada Ltd. 40% ExxonMobil Canada Ltd. 35% BG International Limited 25%	**$11,030,633**
NL15-01-06	262 230	Statoil Canada Ltd. 34% ExxonMobil Canada Ltd. 33% BP Canada Energy Group ULC 33%	**$225,158,741**
NL15-01-07	254 321	Statoil Canada Ltd. 34% ExxonMobil Canada Ltd. 33% BP Canada Energy Group ULC 33%	**$206,258,741**
NL15-01-08	268 755	Statoil Canada Limited 50% BP Canada Energy Group ULC 50%	**$35,140,653**
NL15-01-09	139 477	Statoil Canada Ltd. 100%	**$423,189,945**
NL15-01-10	163 008	Nexen Energy ULC 100%	**$261,000,000**
NL15-01-11	169 578	NA	**NA**

Total Successful Bid Amount	**$1,204,953,713**

3.3 Exploration Program

3.3.1 Drilling Programs

Offshore Activity

Utilizing the West Hercules semi-submersible drilling rig, six exploration wells were drilled in the Flemish Pass. Statoil Canada, with co-venture partners, drilled Bay du Nord P-78, Bay du Nord L-76Z, Bay du Nord L-76, Cupids A-33, Bay d-Espoir B-09, and Fitzroya A-12Z . No results have been released for either of these wells and drilling results can remain confidential for two years after the well termination date.

Onshore Activity

Investcan Energy Corporation is the permit holder of the onshore exploration permits in the Flat Bay area and Black Spruce Exploration Corporation holds permits in the Deer Lake area of Western Newfoundland. No drilling programs were conducted on any onshore permits in 2015.

3.3.2 Geoscience Programs

Offshore Activity

2015 continued to be a busy year with many geoscience programs being conducted throughout the offshore area (see figure 18).

Statoil Canada completed both a Seabed Survey as well as a Geotechnical program in the Flemish Pass area. The seabed survey was conducted over the Bay du Nord field utilizing the Fugro Searcher, while the Maersk Chancellor completed the work for the geotechnical program.

MG3/UK ltd. utilizing the research vessel Neptune completed a geotechnical program in the northeast Newfoundland slope and the offshore Labrador area on behalf of Nalor Energy—Oil and Gas. The program involved the collection of core samples for geo-chemistry analysis.

Three 2-D seismic programs were completed by Multi-Klient Invest AS. Utilizing the Atlantic Explorer, 14,404 line kilometers (km) of data was acquired in the southern Grand Banks area, while the Sanco Spirit acquired 9,951 line km of data in the South Labrador Sea region. The Sanco Spirit also complete a 2-D seismic survey in the northeastern Newfoundland slope region acquiring 2,483 line km.

Two 3-D seismic programs were also conducted by Multi-Klient Invest AS. The seismic vessel Ramform Valiant acquired 5,293 km^2 in the northeastern Newfoundland slope over Exploration Licenses 1135. Of worthy to note is that this license was only issued in January, 2015 to ExxonMobil (40%), Suncor Energy (30%) and ConocoPhillips Canada (30%).

The Ramform Viking completed a 4,987 km^2 program in the West Orphan Basin over Sector NL-02-EN which is scheduled for a 2016 licensing round.

HMDC conducted a 4-D seismic program in the Grand banks area over the Hibernia Field utilizing the Western Geco Trident. A total of 758 km^2 of data was acquired during the duration of the program.

Figure 18 - Seismic Vessels in St. John's harbour

Source: Department of Natural Resources

Onshore Activity

In 2007, the provincial government announced a $5.0 million investment into the Petroleum Exploration Enhancement Program (PEEP). The program funds research on the sedimentary basins of onshore Western Newfoundland and is focused on research projects, studies and analyses with the aim to improve our knowledge of the petroleum systems of these basins.

PEEP is jointly administered by the Department of Natural Resources (DNR) and Nalcor Energy – Oil and Gas. Since 2008, there have been 28 projects approved of which 16 are complete, with 12 ongoing. Approximately $3,500,000 has been allocated to date and funds remain for 2016 / 2017.

In 2015, a geochemical study, "Variations of Redox conditions across the Cambrian-Ordovician GSSP (Green Point Formation) in western Newfoundland (Canada)", was approved to conduct combined petrographic and geochemical techniques to determine the basis of the organic-rich black shale.

Final reports, project summaries and presentations for all PEEP projects are available at:
http://www.nr.gov.nl.ca/nr/energy/petroleum/onshore/peep.html

3.4 Regulatory Affairs

3.4.1 License/Permit Updates

As a result of the 2013/2014 Call for Bids three new Exploration Licenses were issued in January, 2015.

1/ EL-1135 - CFB NL 13-01 Flemish Pass Basin
Successful bid $559 million - ExxonMobil (40%), Suncor (30%) and ConocoPhillips (30%)

2/ EL - 1136 - CFB NL 13-02 Carson Basin
Successful bid $21 million - ExxonMobil (50%) and Suncor (50%)

3/ EL - 1137 - CFB NL14-01 Jeanne d'Arc Basin
Successful bid - $16.7 million - ExxonMobil (100%).

Seven exploration licenses were relinquished in 2015 and the land was returned to crown reserve. Three were in the Jeanne d'Arc Basin (ELs 1093, 1113 and 1117), one in the Flemish Pass Basin (EL - 1110), one in the Anticosti Basin (EL - 1116) and two in the Laurentian Basin (ELs - 1118 and 1119).

Two additional license changes occurred in 2015. The Hibernia Field Production License PL - 1001 which was issued in 1990 for a period of 25 years was granted an extension for an additional 25 years. Also the Terra Nova Field was granted an additional Significant Discovery License (SDL - 1053) for land that is contained within the field but was not included in previous discovery areas.

Lastly in June, 2015 BG Group announced that it had purchased Repsol E&P Canada's interest in the three exploration licenses (ELs 1123, 1125 and 1126) operated by Statoil in the Flemish Pass Basin. BG Group is a British based international oil and gas exploration and development company and early in 2015 it was announced that BG was being acquired by Royal Dutch Shell with the sale closing scheduled for early in 2016.

3.4.2 Hydraulic Fracturing 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.

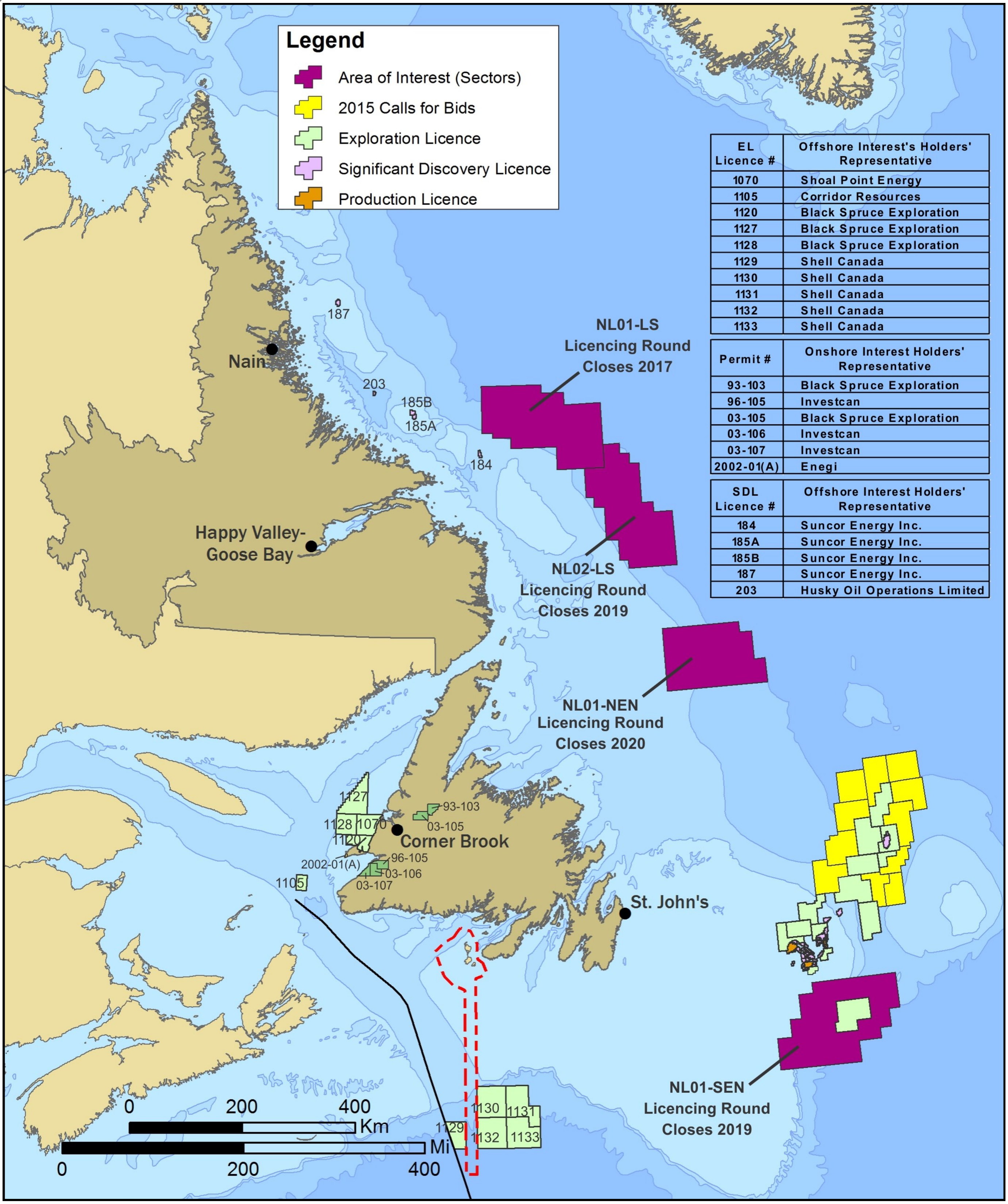
In October 2014, a five member independent panel was appointed by the Minister of Natural Resources to conduct a public review and make recommendations on whether or not hydraulic fracturing should be undertaken in Western Newfoundland. The mandate of the panel is to conduct a public review and advise 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. In 2015 the Panel's work included the following:

- Creating a website (www.nlhfrp.ca) for the sharing of information between the general public, stakeholder groups and the Panel;
- Gathering information through direct sourcing and commission of documents, and accepting submissions from people who want to provide input to the Panel;
- Conducting four information sessions in western Newfoundland;
- Conducting a public opinion survey about a range of issues related to unconventional oil and gas development in western Newfoundland;
- Completion of relevant supplementary reports by members of the Panel; and
- Visits and meetings in western Newfoundland with stakeholders groups.

The report from the independent panel is expected early/mid 2016.

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



EL Licence #	Offshore Interest's Holders' Representative
1070	Shoal Point Energy
1105	Corridor Resources
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

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

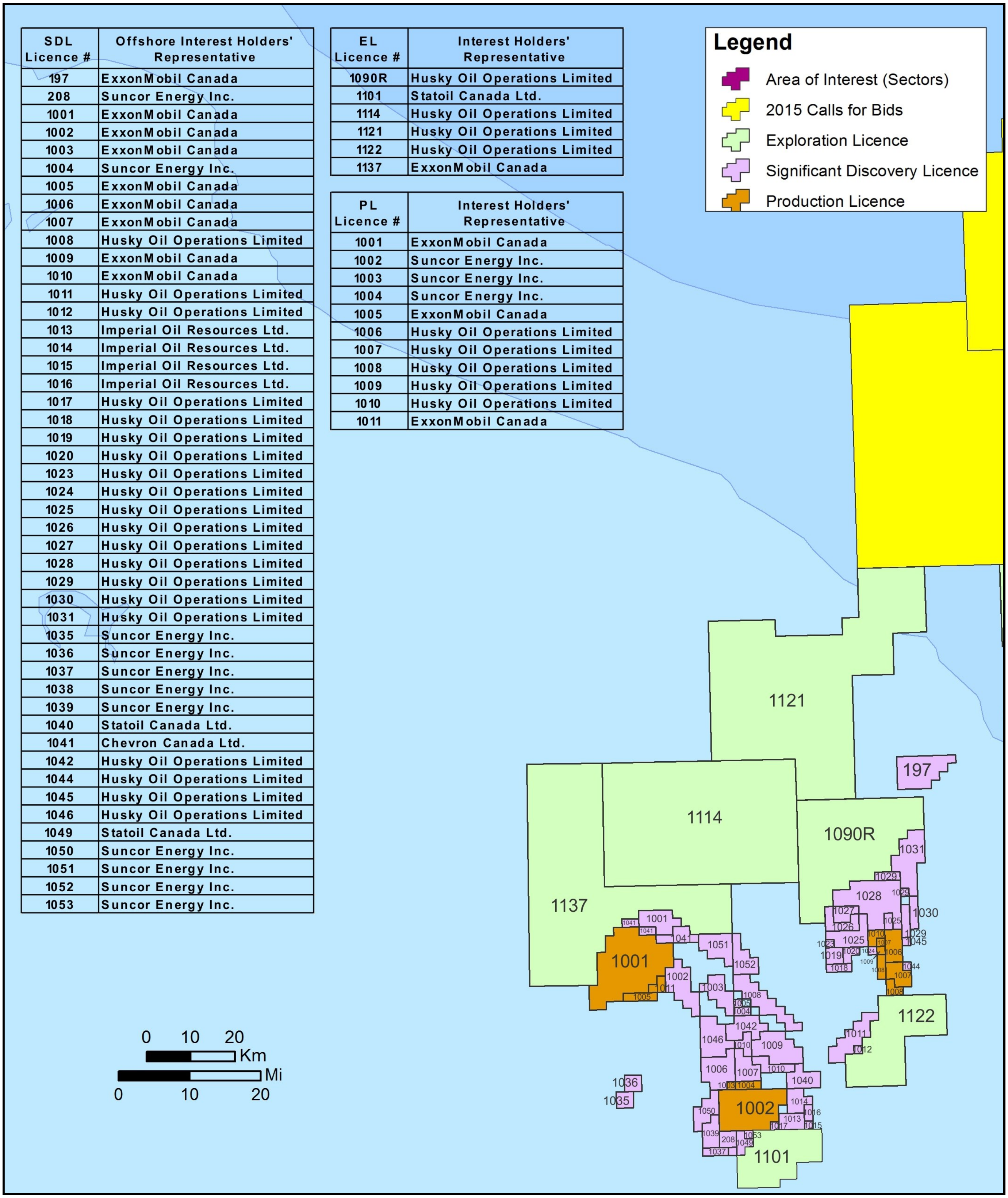
SDL Licence #	Offshore Interest Holders' Representative
184	Suncor Energy Inc.
185A	Suncor Energy Inc.
185B	Suncor Energy Inc.
187	Suncor Energy Inc.
203	Husky Oil Operations Limited

Appendix B - Licence Holders
Jeanne d'Arc Basin Region

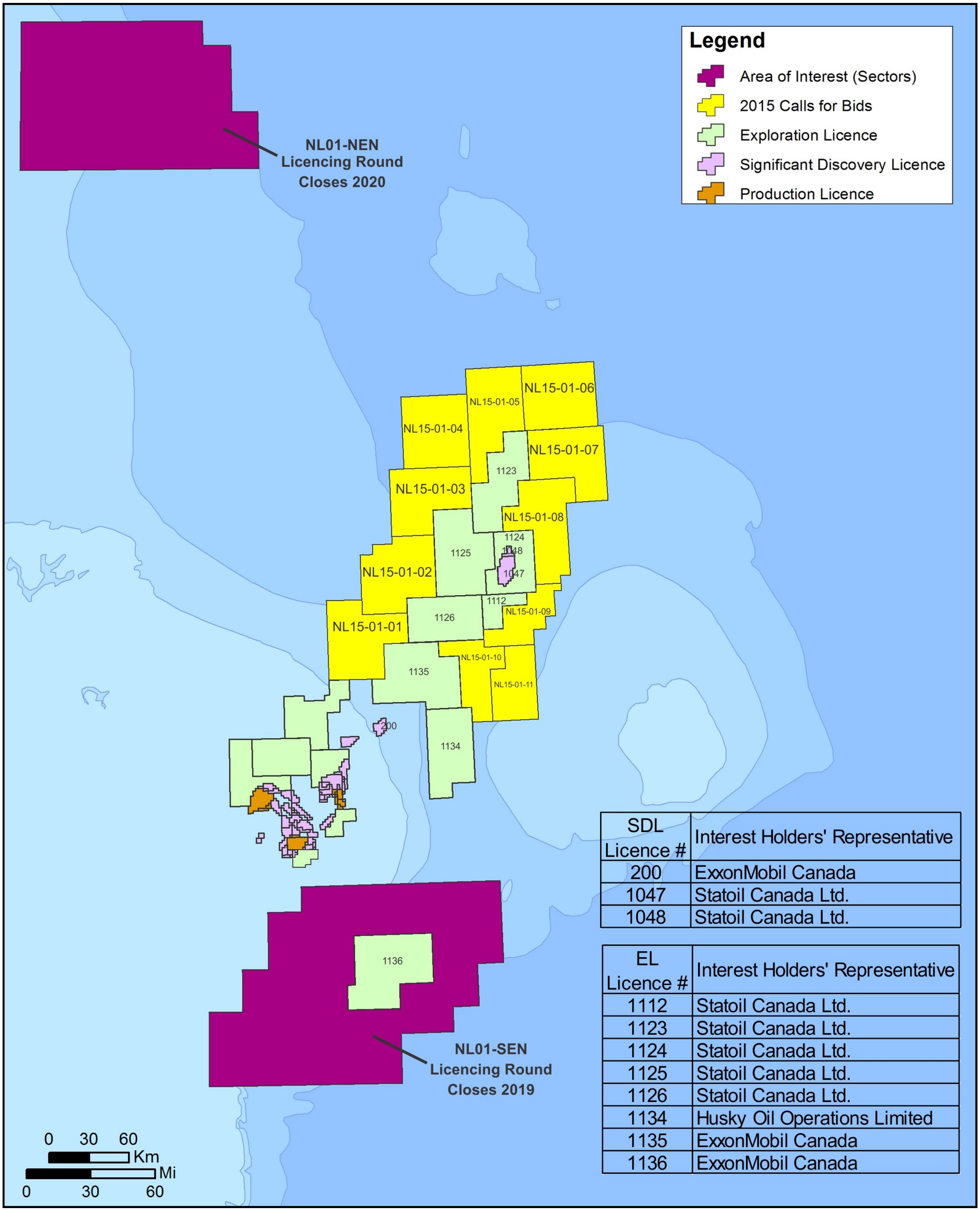
SDL Licence #	Offshore Interest Holders' Representative
197	ExxonMobil Canada
208	Suncor Energy Inc.
1001	ExxonMobil Canada
1002	ExxonMobil Canada
1003	ExxonMobil Canada
1004	Suncor Energy Inc.
1005	ExxonMobil Canada
1006	ExxonMobil Canada
1007	ExxonMobil Canada
1008	Husky Oil Operations Limited
1009	ExxonMobil Canada
1010	ExxonMobil Canada
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.
1053	Suncor Energy Inc.

EL Licence #	Interest Holders' Representative
1090R	Husky Oil Operations Limited
1101	Statoil Canada Ltd.
1114	Husky Oil Operations Limited
1121	Husky Oil Operations Limited
1122	Husky Oil Operations Limited
1137	ExxonMobil Canada

PL Licence #	Interest Holders' Representative
1001	ExxonMobil Canada
1002	Suncor Energy Inc.
1003	Suncor Energy Inc.
1004	Suncor Energy Inc.
1005	ExxonMobil Canada
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

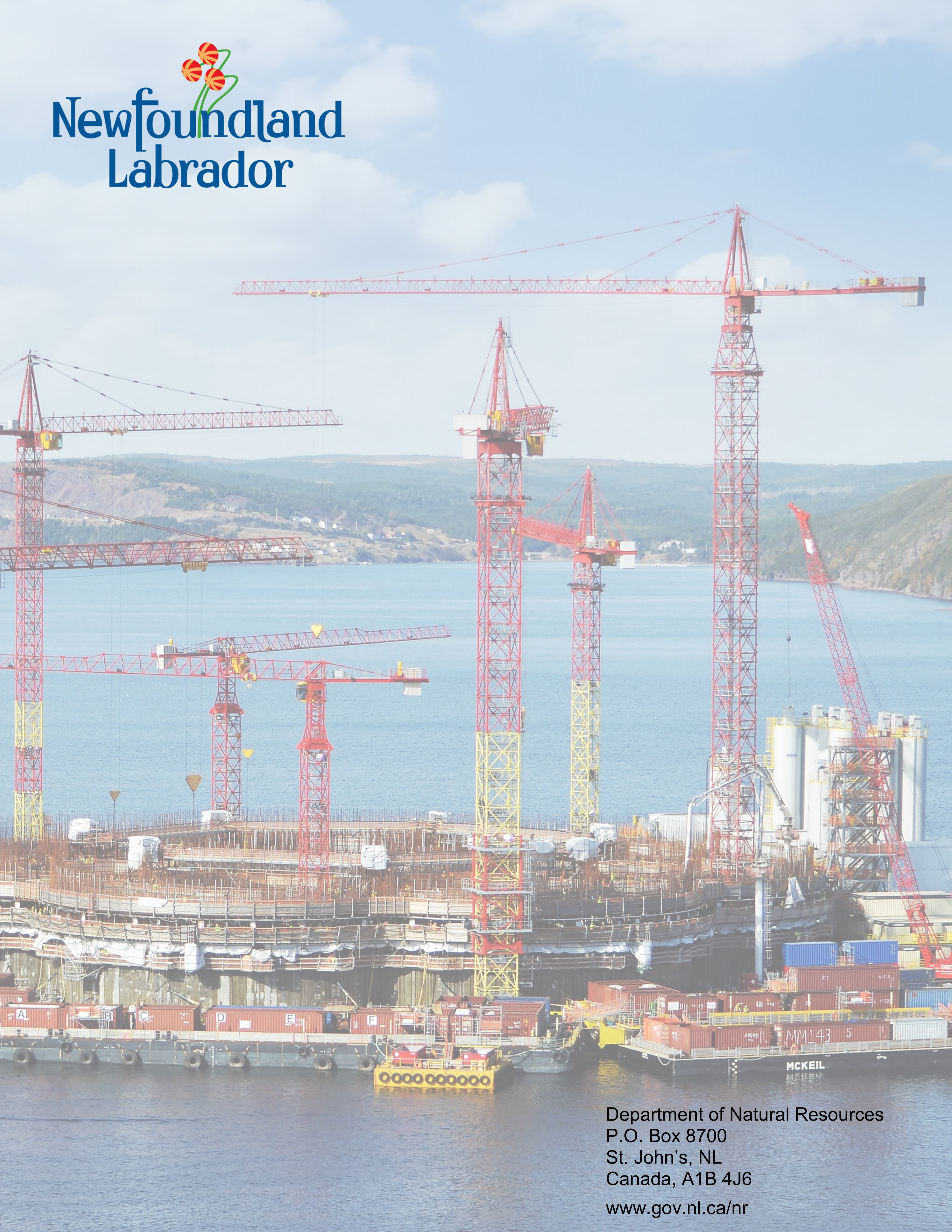


Appendix C - Licence Holders—Flemish Pass Basin Region and South Eastern Newfoundland



SDL Licence #	Interest Holders' Representative
200	ExxonMobil Canada
1047	Statoil Canada Ltd.
1048	Statoil Canada Ltd.

EL Licence #	Interest Holders' Representative
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
1135	ExxonMobil Canada
1136	ExxonMobil Canada



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