

Petroleum Development



Activity Report
2013

 Newfoundland
Labrador

it's happening here.

Department of Natural Resources Petroleum Development Activity Report - 2013

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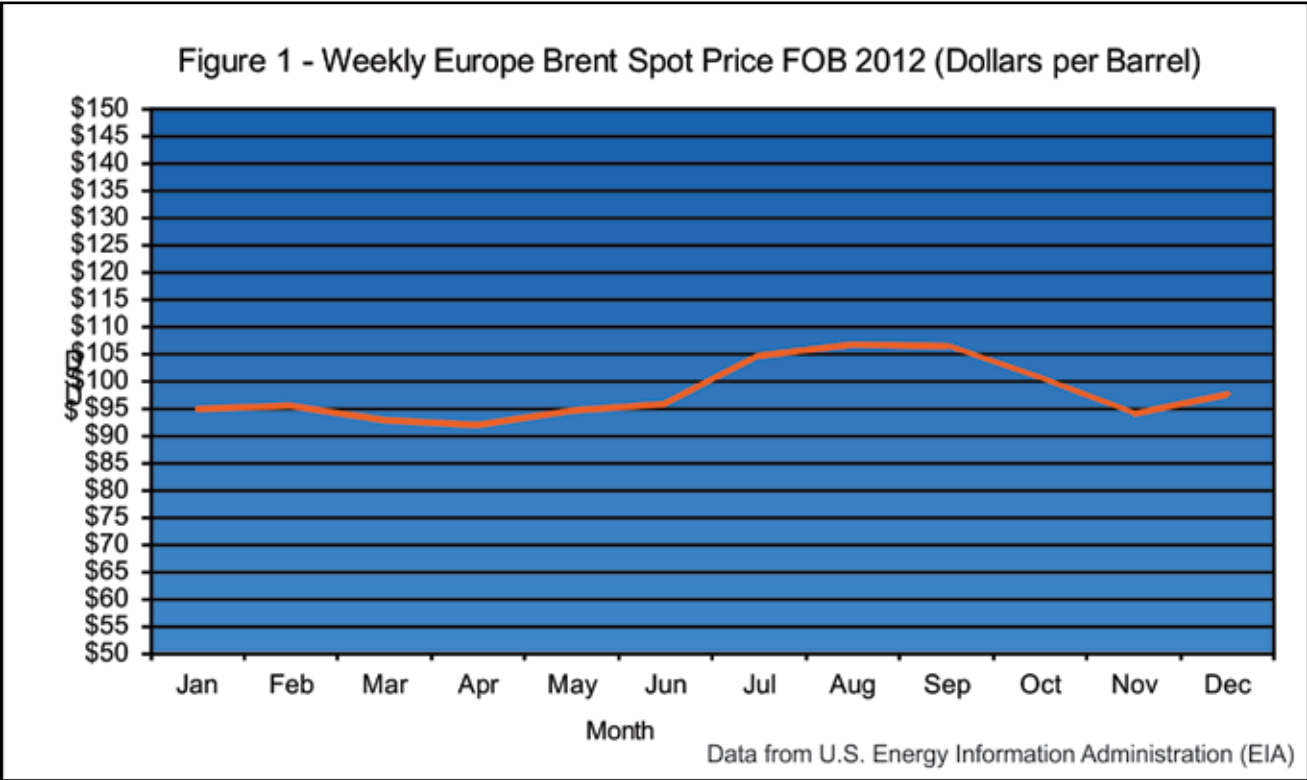
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1.0 Executive Summary

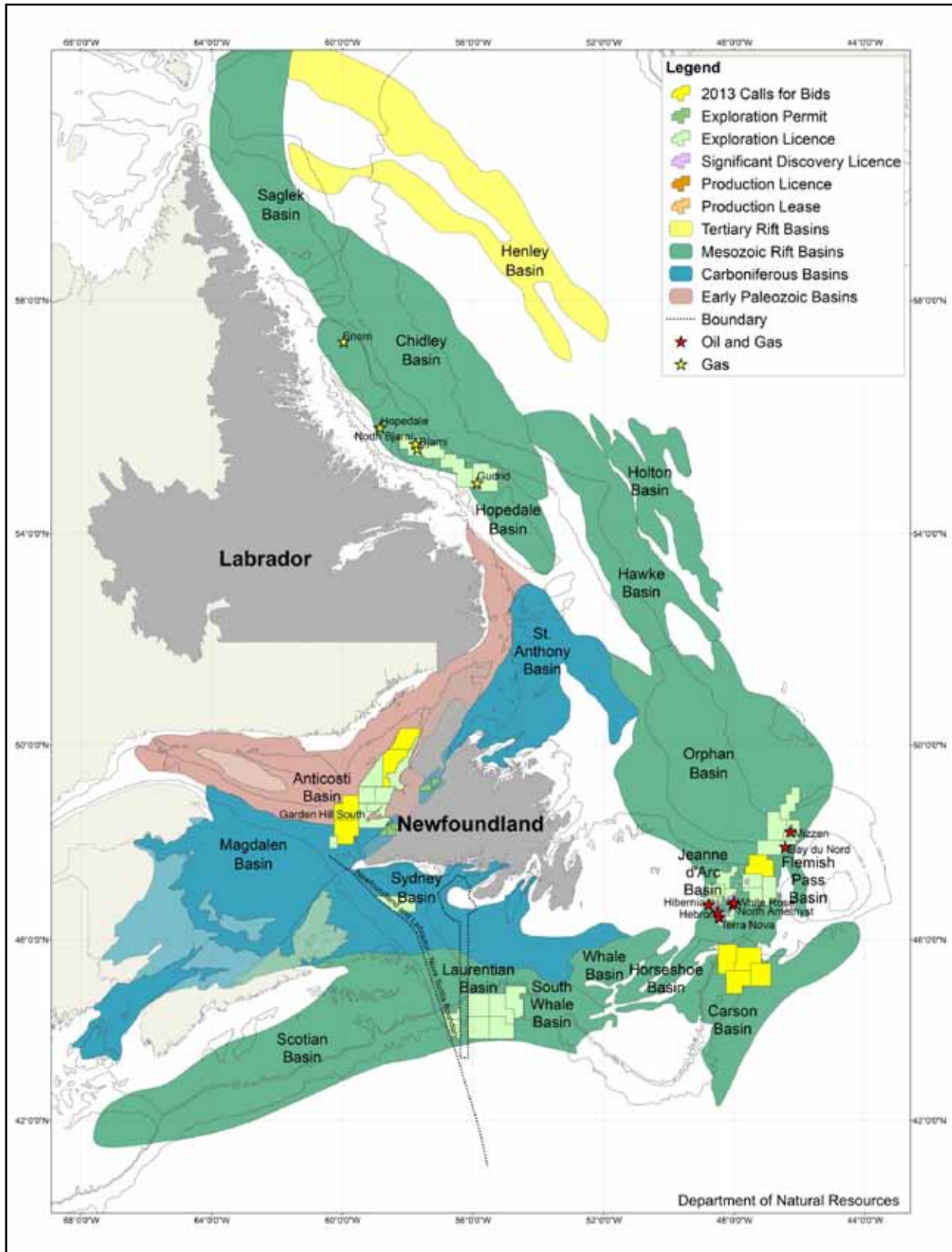
The Province of Newfoundland and Labrador, located on the east coast of North America, has been Canada’s offshore oil producing region for the past 17 years. The province’s four producing fields, Hibernia, Terra Nova, White Rose, and North Amethyst, have produced more than 1.44 billion barrels of oil as of December 31, 2013. This represented approximately 9% of Canada’s crude output and 27% of its conventional light crude production.

Total production in 2013 was 83.6 million barrels of oil. The price of oil remained high, as evidenced by Figure 1 below, and royalties on production continued to be the largest single source of revenue (approximately 30%) for the provincial treasury.



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 on 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 of Newfoundland and Labrador



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 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, 2013, the C-NLOPB had issued 33 exploration licences, 56 significant discovery licences, and 11 production licences (See Appendices A -D). There were a total of 399 wells spud in the province's offshore area by the end of 2013. They comprise 189 development wells, 55 delineation wells, and 155 exploration wells. The exploration and delineation wells have resulted in 56 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. In 2012, the C-NLOPB completed its assessment of Statoil's Mizzen discovery and provided a recoverable resource estimate of 102 million barrels of oil. The C-NLOPB now states 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.

The Government of Newfoundland and Labrador issues land rights in two categories in the offshore area: exploration permits and production leases. There have been approximately 90 wells spud onshore and as of December 31, 2013, the province had seven 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 totalling 1,781 hectares is issued to Enegi Oil Inc. at the Garden Hill South site located on the Port au Port Peninsula.

Newfoundland and Labrador's prospective offshore and onshore basins continued to experience significant exploration interest in 2013. Two seismic programs were completed in the offshore east coast region in 2013. 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 seismic program utilizing the M/V Sanco Spirit. A total of 14,353 km of 2D data was collected in the North East - Newfoundland Slope. ExxonMobil conducted 3D/4D seismic in 2013, comprised of a 53,533 km baseline over a portion of the Hebron field, utilizing the M/V Vespucci. Husky conducted a wellsite survey acquiring approximately 864 km of 2D data over Glenwood & North Hebron.

TGS announced in October 2013 that they have been contracted to continue the multi-client

Table 1 Reserves and Resources

Petroleum Reserves¹ and Resources² Newfoundland Offshore Area (Updated November 13,2013)						
Field	Oil		Gas		NGLs³	
	<i>10⁶ m³</i>	<i>million bbls</i>	<i>10⁶ m³</i>	<i>billion cu. ft.</i>	<i>10⁶ m³</i>	<i>million bbls</i>
Grand Banks						
Reserves						
Hibernia	221.9	1395				
Hebron	112.0	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	0	8.9	315		
Ben Nevis	40.0	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	3603	224.2	7947	63.6	385
Labrador Shelf						
North Bjarni	-	-	63.3	2247	13.1	82
Gudrid	-	-	26.0	924	1.0	6
Bjarni	-	-	24.3	863	5.0	31
Hopedale	-	-	3.0	105	0.4	2
Snorri	-	-	3.0	105	0.4	2
Sub-Total	0.0	0	119.6	4244	19.9	123
Total	571.4	3603	343.8	12191	83.5	508
Produced⁶	225.9	1418	0.0	0	0.0	0
Remaining	346.8	2186	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
⁶ 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.

Canada-Newfoundland Offshore Petroleum Board (C-NLOPB)

2D survey offshore Newfoundland covering a total of 25,000 km. This survey will be acquired in partnership with PGS, utilizing PGS's GeoStreamer technology.

In October 2013, Black Spruce Exploration updated its schedule for drilling conventional wells on the west coast of the province. The company signed a farm-in agreement with U.K. based Enegi Oil for an interest in the Garden Hill production permit 2002-01A. Black Spruce Exploration expects to start drilling at Garden Hill on the Port au Port Peninsula in 2014, pending government approvals.

Major development work continued in 2013 on the new Hebron offshore field developments. ExxonMobil began work on its gravity base structure and in May, the first concrete was poured to the base slab. In August 2013, the center shaft slipform was completed and in September it completed the storage cells and ice wall. In June of 2014, the berm is expected to be removed for the flooding of the dry dock. The GBS will be towed to deep water in July 2014, where the remainder of the central shaft will be built in order to accommodate the mating of the topsides.

Several major contracts were awarded in 2013 regarding the Hebron topsides construction. The contract for the utilities and process module was awarded to Hyundai Heavy Industries in Korea. The partnership of North Eastern Constructors Ltd. consisting of the local Cahill Group of Companies as well as Apply Leirvik based in Norway (collectively referred to as NEAL Partnership) was awarded the contract for the 120 cabin living quarters. This module will be constructed at Cahill's local fabricating facilities as well as the main fabricating hall at the Bull Arm site. The Drilling Support Module (DSM) was awarded to Kiewit Offshore Services in January 2013. The construction of this module will be completed at Kiewit's Cow Head fabrication facility in Marystown, NL. Contracts to construct the remaining components, the helideck, the flare boom and the life boat stations, were awarded in 2013. C&W Offshore was awarded the contracts for both the helideck and the west life boat station, while Talon Energy was successful in winning the bid on the flare boom. Integration of all completed modules remains on schedule for 2016 and first oil in 2017. The platform is designed for production of 150,000 barrels of oil a day with a life expectancy of approximately 30 years.

Husky Energy continued to advance work on development alternatives for the western portion of the White Rose field in 2013. In October 2013, Husky Energy announced that the preferred development option for the White Rose Extension Project will be a wellhead platform to be built at Argentia, NL. To prepare for the work Husky awarded Nova-Scotia based Dexter Construction Co. Ltd. with the contract to build the graving dock.

The primary function of the wellhead platform will be the drilling of production wells for the West White Rose and surrounding areas. The platform will consist of a concrete gravity structure with a topsides consisting of drilling facilities, wellheads and support services including an accommodations unit, utilities module, flare boom and helideck. As there is no processing planned for the platform, oil production will be handled by the Sea Rose FPSO.

In-Province work on the wellhead platform includes project and procurement management, engineering and construction of the graving dock, gates, the concrete gravity structure, accommodations modules, fabrication of the flare boom, helideck, and lifeboat stations.

As of December 31, 2013, Hibernia was operating with 61 development wells. They include 38 oil producers, 18 water injectors, and five gas injectors. Hibernia produced 49.4 million barrels of oil during 2013 for an average production of 135,381 bopd for a 12 month period. Cumulative oil production to December 31, 2013, was 876.5 million barrels representing 62.8% of the total current reserve estimate.

During 2013, Hibernia South Extension development plans continued in the field with the installation of flowlines, jumpers, and subsea equipment. This work was carried out utilizing Technip Canada's Deep Pioneer multi-purpose support ship. Production from pressure support from the water injectors is expected in 2015. The ultra-deepwater semi-submersible drilling rig, West Aquarius, is scheduled to begin drilling the water injector wells in 2014.

As of December 31, 2013, Terra Nova was operating with a total of 30 development wells. They consist of 17 oil producers, 10 water injectors, and three gas injectors. During 2013, the field produced 13.78 million barrels of oil equating to an annualized production of 37,748 bopd. Cumulative field production to the end of 2013 was 349.4 million barrels of oil, which represents 80.0% of the current recoverable reserve estimate.

Production at the Terra Nova field halted on September 26 for a period of 71 days due to a planned shutdown of the Terra Nova FPSO for maintenance and upgrades. Commissioning of the repairs and maintenance program was expected to take upwards of 11 weeks, however, work was completed in 10 weeks. The Terra Nova FPSO returned to location on December 6, 2013. Work completed on the FPSO included replacement of the vessel's main generation gearbox, pressure safety valves, pipe replacements, gas compression inspections, work on the mooring system, replacement of one mooring chain, and maintenance of the eight remaining chains.

Oil production in 2013 from the main White Rose field and the West White Rose pilot program totalled 12.1 million barrels oil, which equates to an annualized daily production of 33,169 barrels of oil. Total cumulative production as of December 31, 2013, was 186.5 million barrels, which represents 60.9% of the total reserve estimate. The main field and the West White Rose pilot program are being developed utilizing 23 development wells, consisting of 10 producers, 10 water injectors, and three gas injectors.

Husky is developing the South White Rose Extension (SWRX) Tie-back with its co-venturers Suncor Energy and Nalcor Energy – Oil and Gas. The proposed SWRX Tie-back will develop oil from both the South Avalon and SWRX pools.

The co-venture parties in the South Avalon Pool are Husky Oil Operations Ltd., 72.5%, and Suncor Energy 27.5%, while the co-venture parties in the SWRX are Husky Oil Operations Ltd., 68.875%, Suncor Energy, 26.125%, and Nalcor Energy – Oil and Gas 5%. The South pool will see two wells: 1 oil producer - expected spud date 2014 - and a gas injector, expected in 2014/15.

The estimated initial 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 have assigned a resource estimate for the West White Rose pool at 40 million barrels of oil. This will be revisited as part of the review of the development plan submission.

As of December 31, 2013, North Amethyst was operating with nine development wells, consisting of five oil producers and four water injectors. Total oil production in 2013 was 8.3 million barrels of oil for an average production of 22,703 bopd. Cumulative production to December 31, 2013, was 31.4 million barrels representing 46.2% of the current total recoverable reserve estimate.

It is expected that 2014 will be an excellent year for the oil and gas industry in the province. Production should return to normal levels as all producing assets are brought back on line and resume operating capacity. Exploration should see increased activity with the two existing drilling units, the Henry Goodrich and the GSF Grand Banks, returning to service from major refits, as well as the arrival of the West Aquarius semi-submersible drilling rig to be used by Statoil for their drilling program in the Flemish Pass and Jeanne d'Arc basins.

2.0 Field Development Summary

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 GBS



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 2010, the C-NLOPB increased the recoverable reserves estimated for the Hibernia field to 1.395 billion barrels of oil, 1.984 trillion cubic feet natural gas, and 210 million barrels of natural gas liquids. The current approved allowable production rate for the Hibernia platform is 220,000 barrels of oil per day.

As of December 31, 2013, Hibernia was operating with 61 development wells comprised of 38 oil producers, 18 water injectors, and five gas injectors.

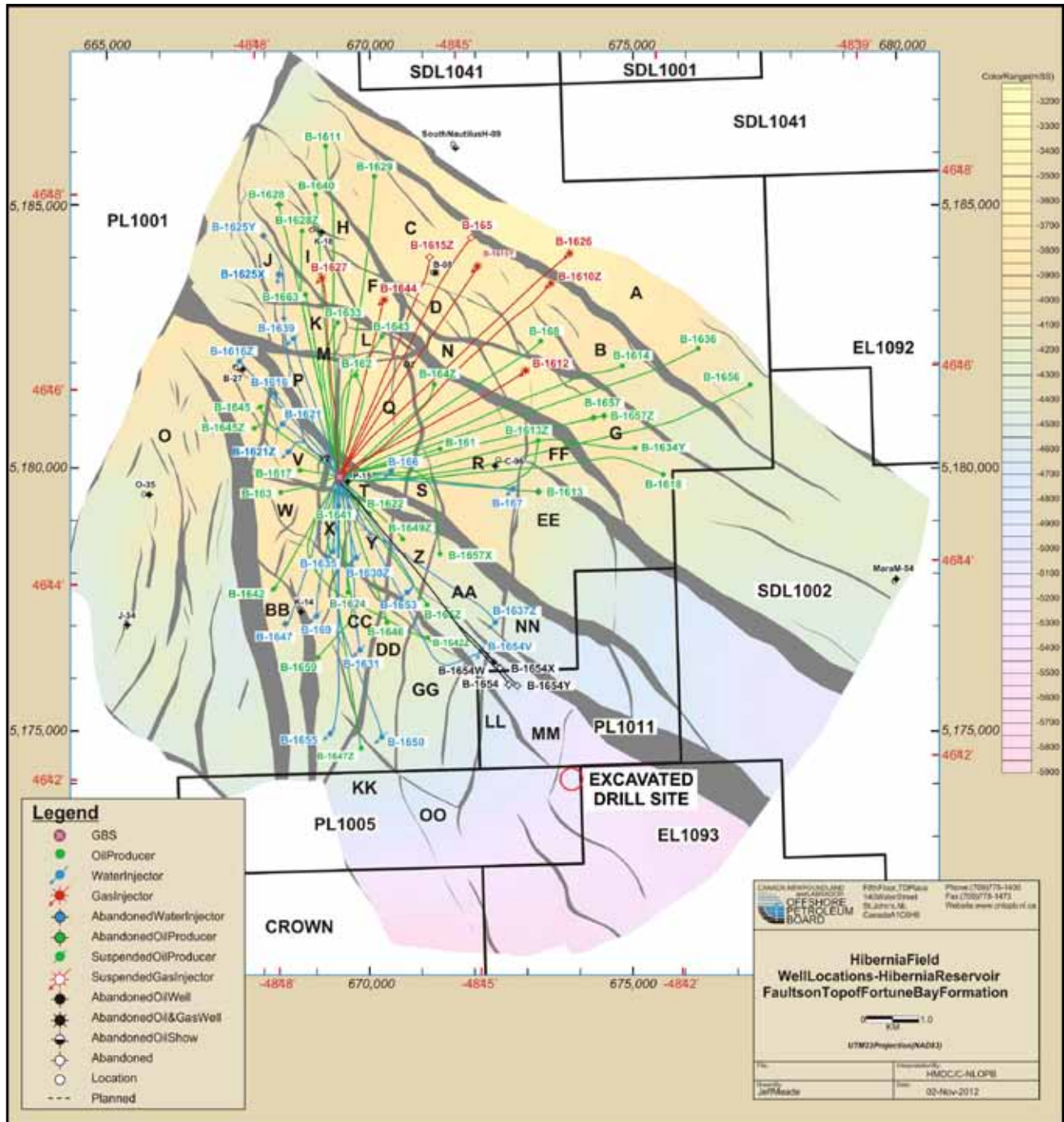
Figure 4 on page 9 shows the well locations in the Hibernia Reservoir. Hibernia produced 49.4 million barrels of oil during 2013 for an average produc-

Table 2

Hibernia Project - Ownership (Main Field)	
ExxonMobil	33.125%
Chevron	26.875%
Suncor	20%
Canadian Hibernia Holding Corp.	8.50%
Murphy Oil	6.50%
Statoil ASA	5%

tion of 135,381 bopd. Cumulative oil production to December 31, 2013, was 876.5 million barrels representing 62.8% of the total current reserve estimate.

Figure 4 - Hibernia Field Well Locations Hibernia Reservoir



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 5 located on page 11 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 Provincial Government 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 20 years longer than originally expected. When natural gas is produced on a commercial basis, this timeframe could be extended further.

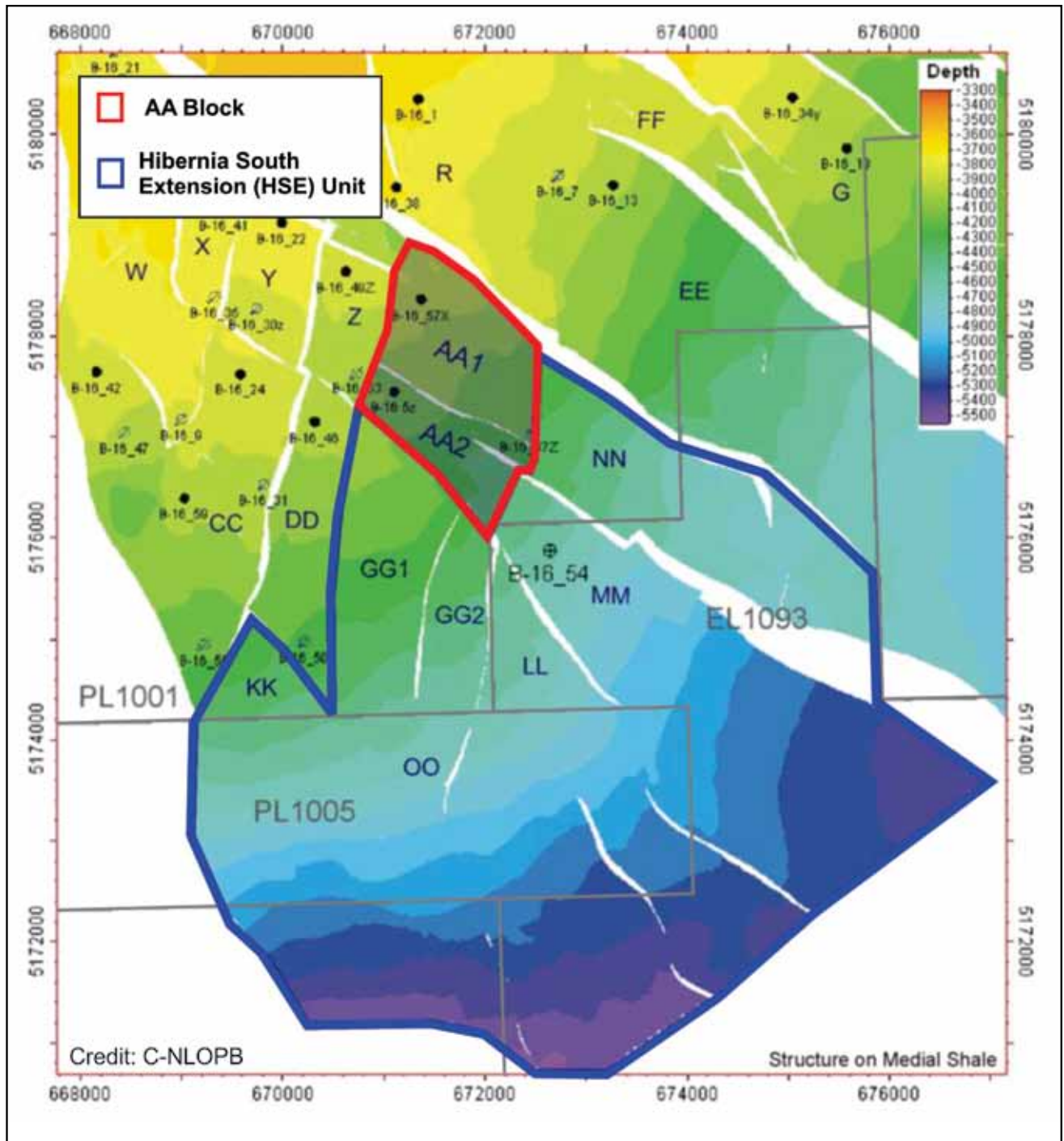
2.1.1 Hibernia Southern Extension - AA Block

The Hibernia AA Block as shown in Figure 5 on page 11 includes the AA1 and AA2 blocks contained 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).

The C-NLOPB has assigned a recoverable reserve estimate of 48 million barrels of oil for the AA Block. Note that these reserves are included in the overall Hibernia recoverable reserve estimate of 1.395 billion barrels of oil mentioned previously in Section 2.1 - Hibernia - Main Field. Production from the AA Block was initially estimated to average 11,000 bopd with peak production reaching 25,000 bopd. The estimated costs for drilling and tie-in activities of the AA Block development was \$196 million CAD and production is expected to last until 2024.

Production from the first oil producer (B-16 57X) occurred on November 27, 2009, and the second oil producer (B-16 5Z) was brought on line on July 28, 2010. In 2013, oil production from these two wells totalled 4.7 million barrels giving an average daily production of 12,892 barrels. The total cumulative production to December 31, 2013, for the AA Block was 33.2 million barrels of oil representing 69% of its total current reserve estimate.

Figure 5 - Hibernia Reservoir Southern Extension Unit Area



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, 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 on page 8. 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.

2.1.2 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 5 on page 11. 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, the portions of the HSE Unit held under Exploration Licence 1093 that are to be developed were transferred to Production Licence 1011 with the ownership positions as shown in Table 4 on page 14.

The C-NLOPB has estimated recoverable reserves in the HSE Unit at 167 million barrels of oil. Note that this figure is also included in the 1.395 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 10 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. 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. In 2013, oil production from these two wells totalled 0.8 million barrels. Oil production has been restricted pending the commencement of water injection

associated with these wells as per good production practice. Total cumulative production to December 31, 2013, was 3.8 million barrels of oil which represents approximately 2.3% of the total recoverable reserve estimate for the HSE Unit.

Dredging for the excavated drill centre to locate the subsea templates and manifolds for the water injection wells was completed in 2012 by Van Oord utilizing the suction hopper dredge vessel HAM 318. This drill centre will be located approximately seven kilometers southeast of the Hibernia GBS and the flowlines and umbilicals connecting it to the Hibernia platform will be through two existing J-tubes installed in the platform at the time of original construction. FMC Technologies was awarded the contract to supply up to six subsea injection trees and wellheads, one manifold and associated control systems for the drill centre. Technip Canada will build and install the seven kilometer long flowlines and umbilicals connecting the water injectors to the platform.

During 2013, development continued in the field with the installation of flowlines, jumpers, and subsea equipment. This work was carried out utilizing Technip Canada's Deep Pioneer multi-purpose support ship. The ultra-deepwater semi-submersible drilling rig, West Aquarius, is scheduled to begin drilling the water injector wells in 2014. Production from pressure support from the water injectors is expected in 2015.

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.

The new ownership structure in PL-1005 and PL-1011 are shown in the following tables.

Table 3

PL 1005 Ownership	
Suncor	22.5%
ExxonMobil	22.5%
Statoil ASA	22.5%
Chevron	22.5%
Nalcor Energy	10%

Table 4

PL 1011 Ownership	
ExxonMobil	29.8125%
Chevron	24.1875%
Suncor	18%
CHHC	7.65%
Murphy	5.85%
Statoil	4.5%
Nalcor Energy	10%

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.

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 Marystown



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 four million

barrels of natural gas liquids. The approved allowable production rate for the Terra Nova FPSO is 180,000 barrels of oil per day.

Table 5

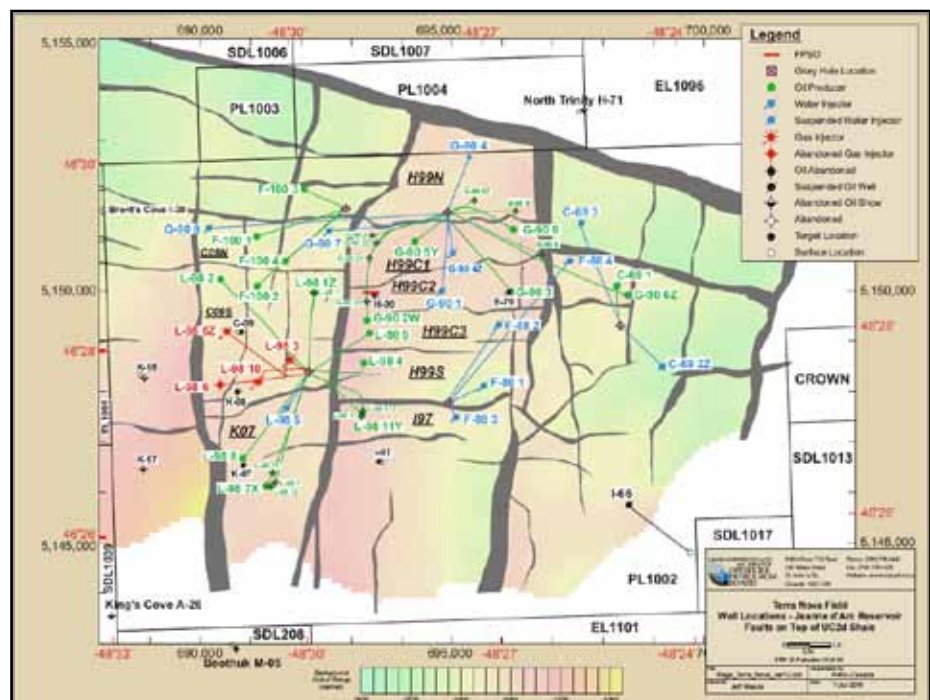
Terra Nova Project - Ownership	
Suncor	37.675%
ExxonMobil	19%
Husky Oil	13%
Statoil ASA	15%
Murphy	10.475%
Mosbacher	3.85%
Chevron	1%

As of December 31, 2013, Terra Nova was operating with a total of 30 development wells, as seen in Figure 7 below. They consist of 17 oil producers, 10 water injectors, and three gas injectors. During 2013, the field produced 13.78 million barrels of oil equating to an annualized production of 37,748 bopd. Cumulative field production to the end of 2013 was 349.4 million barrels of oil which represents 60% of the current recoverable reserve estimate.

Production at the Terra Nova field halted on September 26 for a period of 71 days due to a planned shutdown of the Terra Nova FPSO for maintenance and upgrades. The planned shutdown was extended from the original estimated four week period when a routine inspection detected damage in one of the mooring chains. Commissioning of the repairs and maintenance program, expected to take upwards of 11 weeks, was completed in 10 weeks. Work completed on the FPSO when it was moored in Conception Bay, NL included re-

placement of the vessel's main generation gearbox, pressure safety valves, pipe replacements, gas compression inspections, work on the mooring system, replacement of one mooring chain, and maintenance on the eight remaining chains. The Terra Nova FPSO returned to location on December 6, 2013.

Figure 7 - Terra Nova Field Well Locations



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 a 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, 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 6

White Rose Project - Ownership	
Husky Energy	72.50 %
Suncor	27.50 %

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 North Avalon Pool. Figure 9 on page 17 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 ad-

Figure 8 - White Rose FPSO SeaRose in Belfast Dry Dock



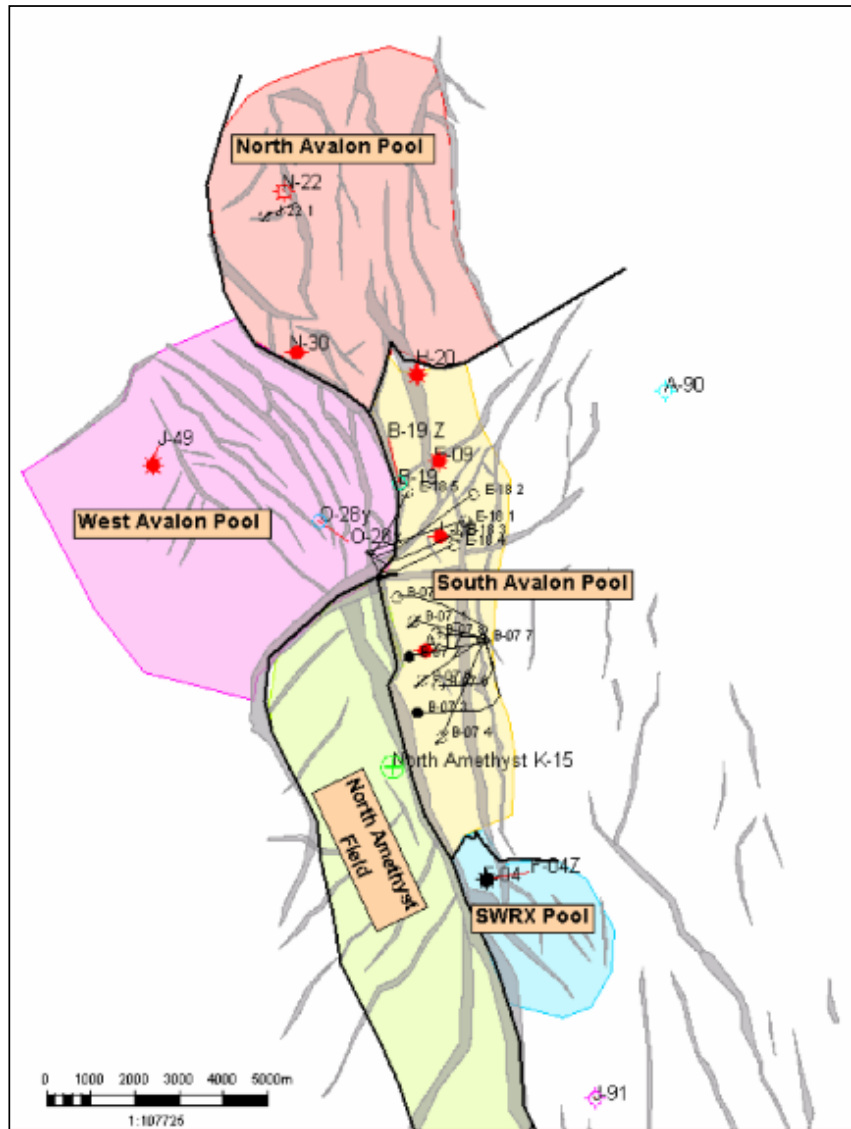
adjacent to the White Rose field and discussed in more detail in Section 2.4 of this report. Production from the North Amethyst field is also being processed by the SeaRose FPSO through a subsea tieback.

Oil production in 2013 from the main White Rose field and the West White Rose pilot program discussed in section 2.3.1 totalled 12.1 million barrels oil, which equates to an annualized daily production of 33,169 barrels of oil. Total cumulative production as of December 31, 2013, was 186.5 million barrels, which represents 60.9% of the total reserve estimate. The main field and the West White Rose pilot program are being developed utilizing 23 development wells, consisting of 10 producers, 10 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

Figure 9 - White Rose Development Area



Credit: Husky Energy

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 below) is currently under construction at the Hyundai Samho Shipyard in South Korea with an expected completion date late in 2014. After testing and commissioning, the rig will commence transit to Newfoundland with an estimated start date of early to mid 2015. 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 schematic, 6th generation semi-submersible



Credit: Husky Energy

2.3.1 West White Rose Extension

Table 7

Development of the West White Rose portion of the field (West Avalon Pool) has been under analysis by the partners since 2001. In 2010, a development plan amendment was submitted and

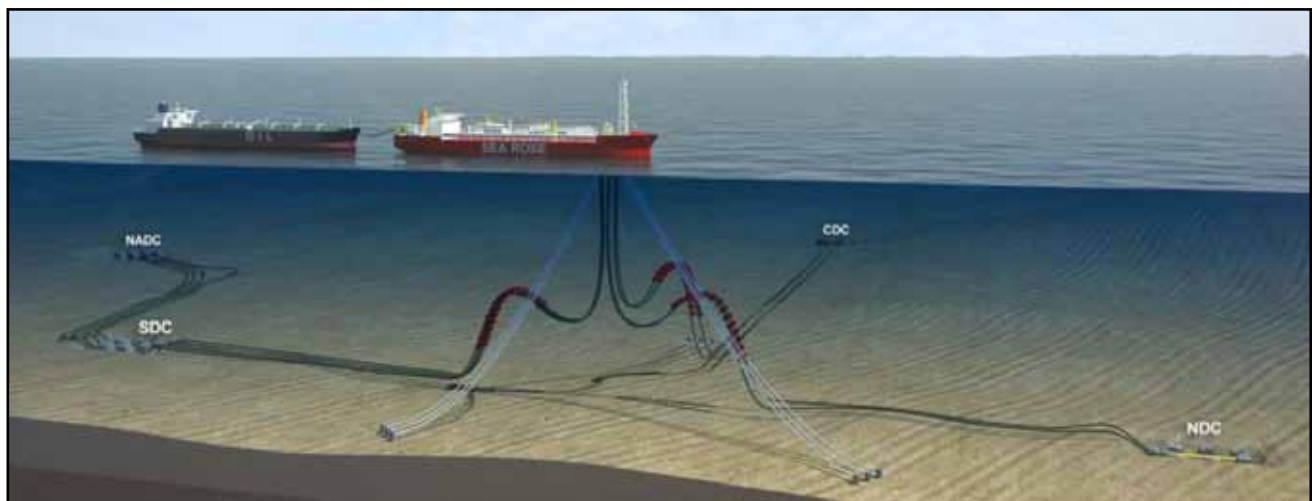
West White Rose Project - Ownership	
Husky Energy	68.875%
Suncor	26.125%
Nalcor Energy	5.0%

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 2013, the pilot scheme produced 3.4 million barrels of oil raising total cumulative production at the extension to 5.8 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.

In October 2013, Husky Energy announced that the preferred development option for the White Rose Extension Project is a wellhead platform (WHP). ARUP Canada has completed

Figure 11 - White Rose Field Layout 2012



Credit: Husky Energy

the front end engineering and design (FEED) and is currently conducting the detailed engineering for the wellhead platform and the graving dock. To prepare for construction of the estimated 172,000 ton gravity based structure, to be built at Argentia, NL, Husky awarded Nova-Scotia based Dexter Construction Co. Ltd. with the contract to build the graving dock.

The primary function of the wellhead platform will be the drilling of production wells for the West White Rose and surrounding areas. The platform will consist of a concrete gravity structure with a topsides consisting of drilling facilities, wellheads, and support services, including an accommodations unit, utilities module, flare boom, and helideck. The consortia of Mustang/PSN has been contracted to complete the pre-FEED, FEED, and detailed engineering design for the WHP topsides. As there is no processing planned for the platform, oil production will be handled by the Sea Rose FPSO.

In-Province work on the wellhead platform will include project and procurement management; engineering and construction of the graving dock, gates, the concrete gravity structure, accommodations modules, fabrication of the flare boom, helideck, and lifeboat stations. The pre-qualification process for many of these units has commenced and awarding of the contracts is expected in 2014.

Husky Energy and the Government of Newfoundland and Labrador signed a Benefits Agreement for the construction of the wellhead platform on October 10, 2013. Final sanctioning of the estimated \$2.5 billion wellhead platform development option is expected by the co-venture partners in 2014 and first oil is expected in 2017.

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 drill centre, as well as a new drill centre, to be constructed approximately four kilometers further south. The C-NLOPB have assigned a resource estimate for the South White Rose Extension of 24 million barrels of oil, which is also included in the total reserve/resource estimate for White Rose as detailed in Section 2.3.

Since approval of the development plan amendment in 2007, Husky Energy has been evaluating options for the production of resources from the South White Rose Extension, as well as the South Avalon portion of the main White Rose field. In 2012, Husky Energy announced that it would be applying to the Canada-Newfoundland and Labrador Offshore

Petroleum Board for 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 includes 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 nine 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 utilizing the suction hopper vessel, Cristobal Colon, and in 2013 a new gas injector was completed. Further development is planned for 2014 including installation of subsea equipment including christmas trees, manifolds, and flowlines. First oil production from SWRX is planned for late in 2014. The total cost of the project is \$1.2 billion CAD including \$590 million for drilling and completions and \$495 million for subsea infrastructure.

Figure 12 - Cristobal Colon docked in St. John's Harbour



Photo: Department of Natural Resources

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 13 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.

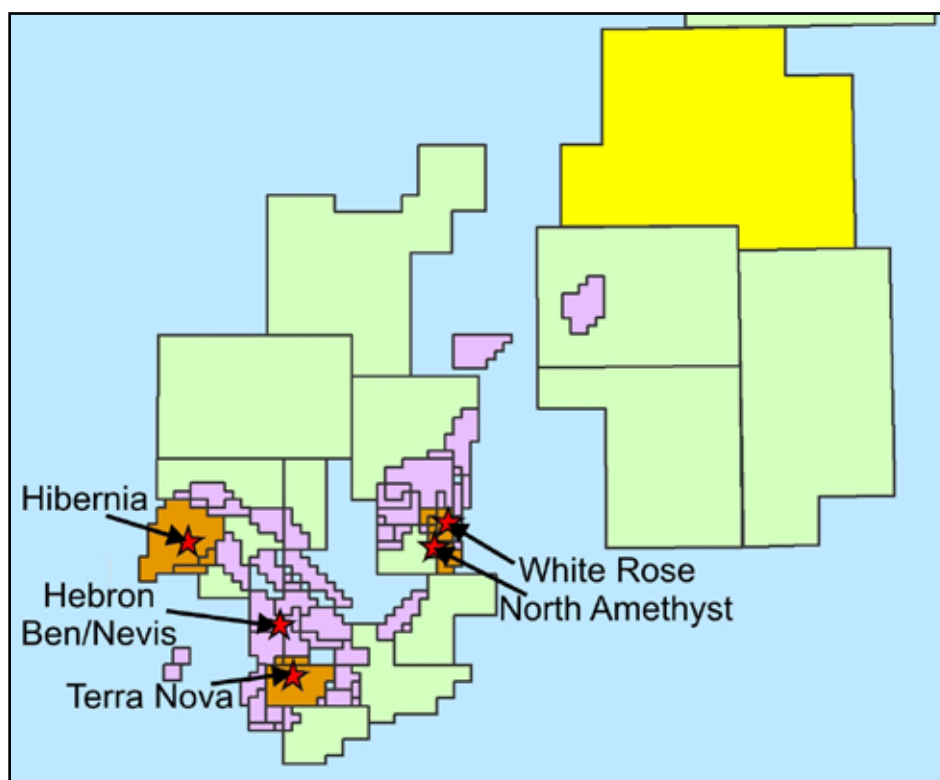
Table 8

North Amethyst Project - Ownership	
Husky Energy	68.875 %
Suncor	26.125 %
Nalcor Energy	5.0 %

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. Nine wells were originally planned for the development, including four oil producers and five water injectors. Flexible underwater flowlines connect the field to the SeaRose FPSO, which is located approximately six kilometers away. Initial production from North Amethyst occurred on May 31, 2010, from the oil well G-25 2.

As of December 31, 2013, North Amethyst was operating with nine development wells, consisting of five oil producers and four water injectors. Total oil production in 2013 was 8.3 million barrels of oil for an average production of 22,703 bopd. Cumulative production to December 31, 2013, was 31.4 million barrels representing 46.2% of the current total recoverable reserve estimate.

Figure 13 - Jeanne d’Arc Basin

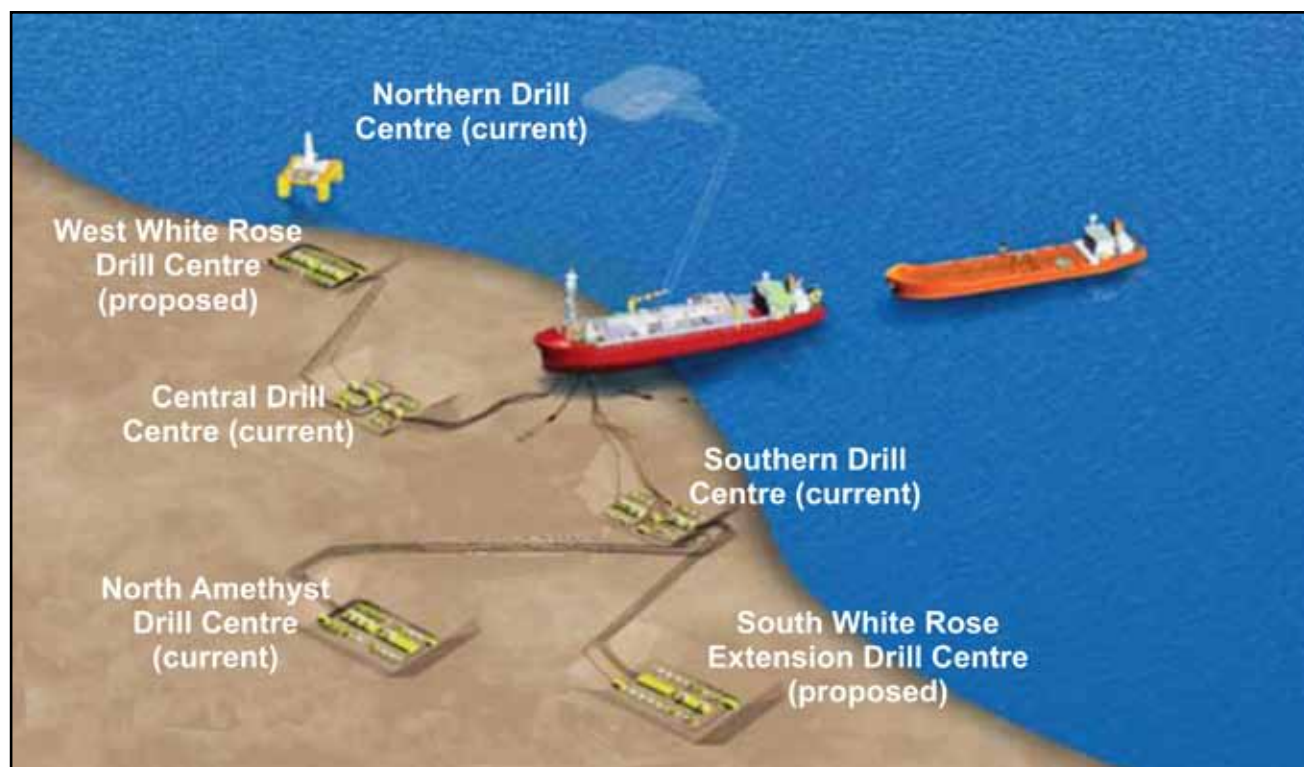


Credit: Department of Natural Resources

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. It is anticipated that the North Amethyst Hibernia development will consist of one production well and one water injection well. Husky's preferred option is to drill a delineation pilot/development producer from the Central Drill Center as illustrated in Figure 14, in the White Rose field. This approach should allow for a better understanding of the North Amethyst Hibernia Formation. The Proponent previously completed a dual zone water injection well, North Amethyst G-25 4, in 2010 for both the Ben Nevis/Avalon and Hibernia Formations.

Figure 14 - North Amethyst Tie Back Development via SeaRose FPSO



Credit: 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, nine 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 (See Figure 15 on page 25 for pool and reservoir nomenclature). 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.

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.

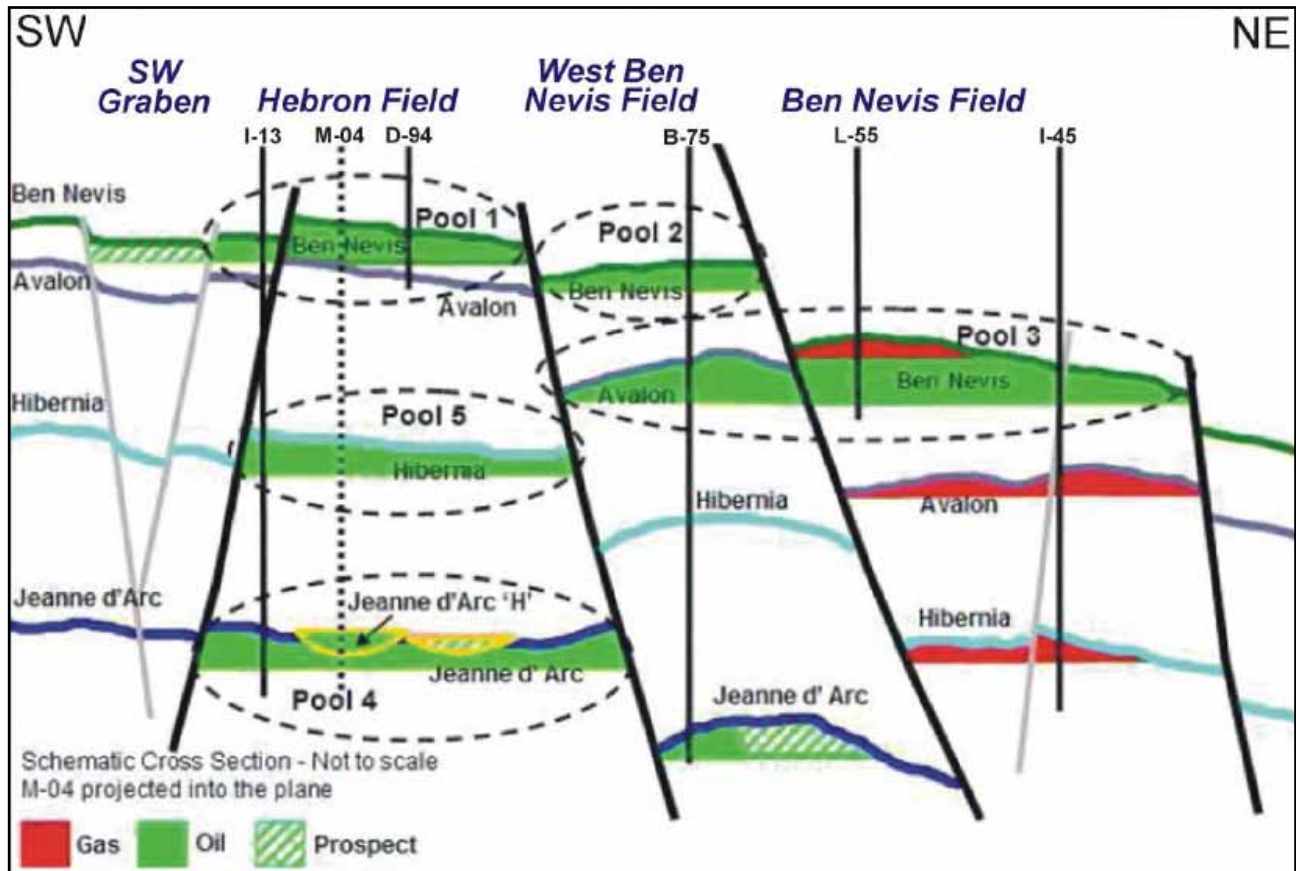
In 2011, ExxonMobil submitted the Hebron Development Plan to the C-NLOPB and in 2012, the C-NLOPB approved the development plan, subject to certain terms and conditions. This decision was subsequently ratified by both the Federal and Provincial Governments on May 31, 2012. The co-venture partners completed 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 15 on page 25. The main Hebron field includes pool 1 followed in a vertically stacked arrangement by pools five and four respectively. Slightly to the northeast is the West Ben Nevis field, which contains pool two, and further northeast is the Ben Nevis field, which includes pool three. 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.

Table 9

Hebron/Ben Nevis Project Ownership	
ExxonMobil	36.0429%
Chevron	26.628%
Suncor	22.7289%
Statoil ASA	9.7002%
Nalcor Energy	4.9%

Figure 15 - Schematic cross-section across the Hebron Asset area



Credit: Modified from ExxonMobil Canada Properties, Hebron Project Development Plan

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 at the time of sanctioning in December 2013. Construction of the actual 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 preparations were underway to flood the dry dock and float the GBS to its deepwater site where more slip forming will occur in 2014 (See Figure 16 on page 26).

In 2012, WorleyParsons was awarded the engineering, procurement, and construction contract for the topsides. WorleyParsons previously held the contract for the FEED and detailed design work. 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 17 on page 27).

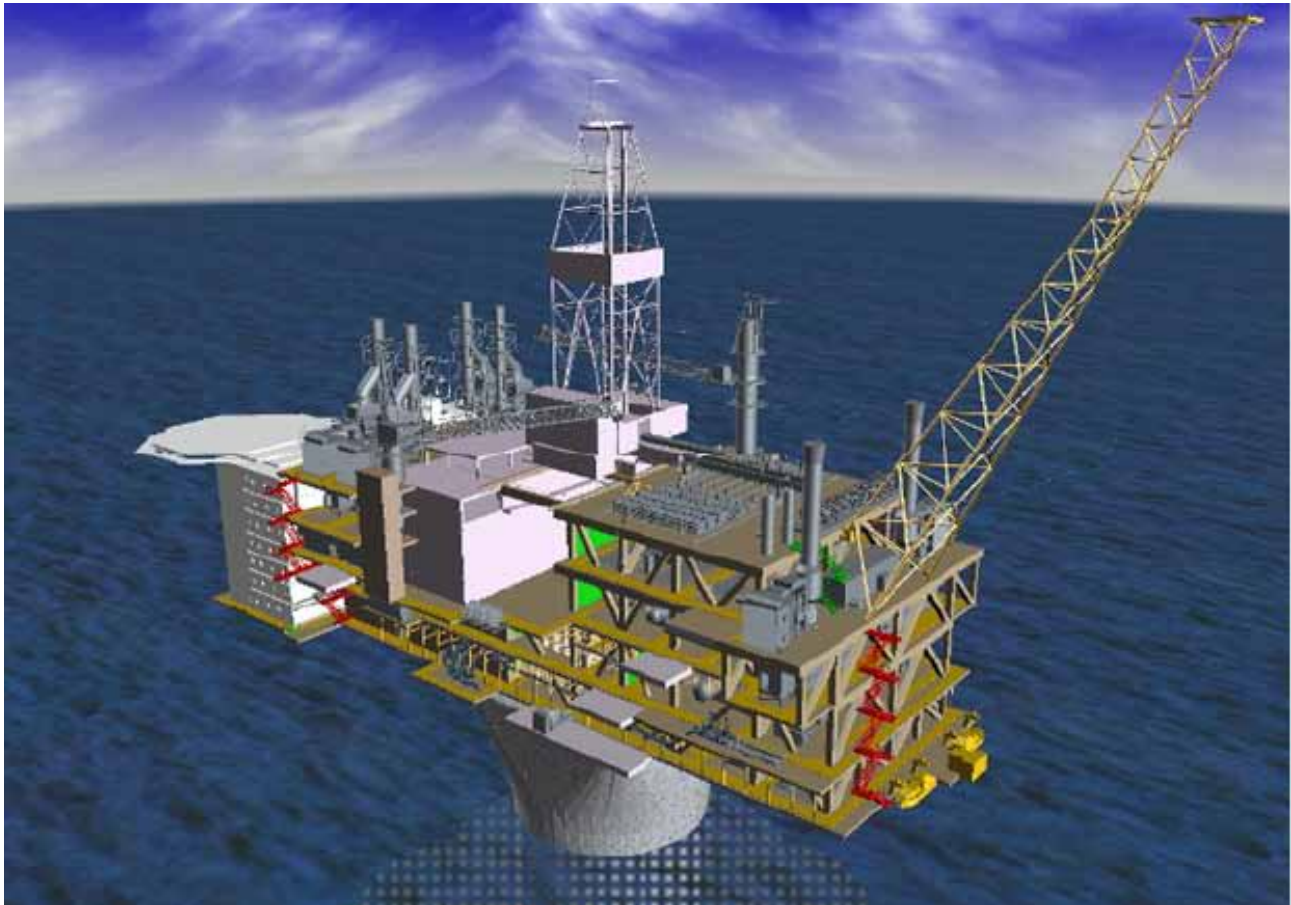
Advancement on the construction of all topsides modules occurred in 2013. The contract for the utilities and process module was awarded to Hyundai Heavy Industries in Korea in 2012 and the cutting of first steel occurred in July 2013. Hyundai also holds the contract for the DES and first steel for that module was cut in October 2013.

**Figure 16 - Hebron GBS under construction
Bull Arm fabrication site, August 2013**



The partnership of North Eastern Constructors Ltd., consisting of the local Cahill Group of Companies as well as Apply Leirvik based in Norway (collectively referred to as NEAL Partnership), was awarded the contract for the 120 cabin living quarters in 2012. This module is being constructed at Cahill's local fabricating facilities, as well as the main fabricating hall at

Figure 17 - Proposed Hebron Development



Credit: ExxonMobil

the Bull Arm site. First steel was cut on this project in March 2013. The DSM was awarded to Kiewit Offshore Services in January 2013. The construction of this module commenced in May 2013 with the cutting of first steel at Kiewit's Cow Head fabrication facility in Marys-town, NL.

Also in 2013, contracts to construct the remaining components, the helideck, the flare boom, and the life boat stations, were awarded. C&W Offshore was awarded the contracts for both the helideck and the west life boat station, while Talon Energy was successful in winning the bid on the flare boom. ExxonMobil has stated that the integration of all completed modules remains on schedule for 2016 and first oil in 2017. The platform is designed for production of 150,000 barrels of oil a day and should be in production for approximately 30 years.

2.6 Garden Hill South Field

Garden Hill South is located onshore western Newfoundland on the Port au Port Peninsula, as identified in Figure 18 below. 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.

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 and 2012. During intermittent production in 2013, a total of approximately 2,160 barrels of oil was recovered raising the total cumulative production at the Garden Hill South site to approximately 41,900 barrels of oil.

In July 2013, Black Spruce Exploration Corp. (BSE), a privately held USA based exploration and production company, announced that it

had signed a farm-in agreement with Enegi Oil on the Garden Hill South production lease. The farm-in agreement calls for BSE to drill five wells to earn a 50% working interest in the lease. BSE stated that the first two wells are planned for 2014 close to the PAP 1 to help delineate and aid in the further development of the field. These wells are subject to BSE relocating their drilling rig to the area and obtaining the necessary regulatory approvals.

Figure 18 - Location of Port au Port Peninsula



Credit: Department of Natural Resources

3.0 Regional Activity Update

3.1 New Scheduled Land Tenure System

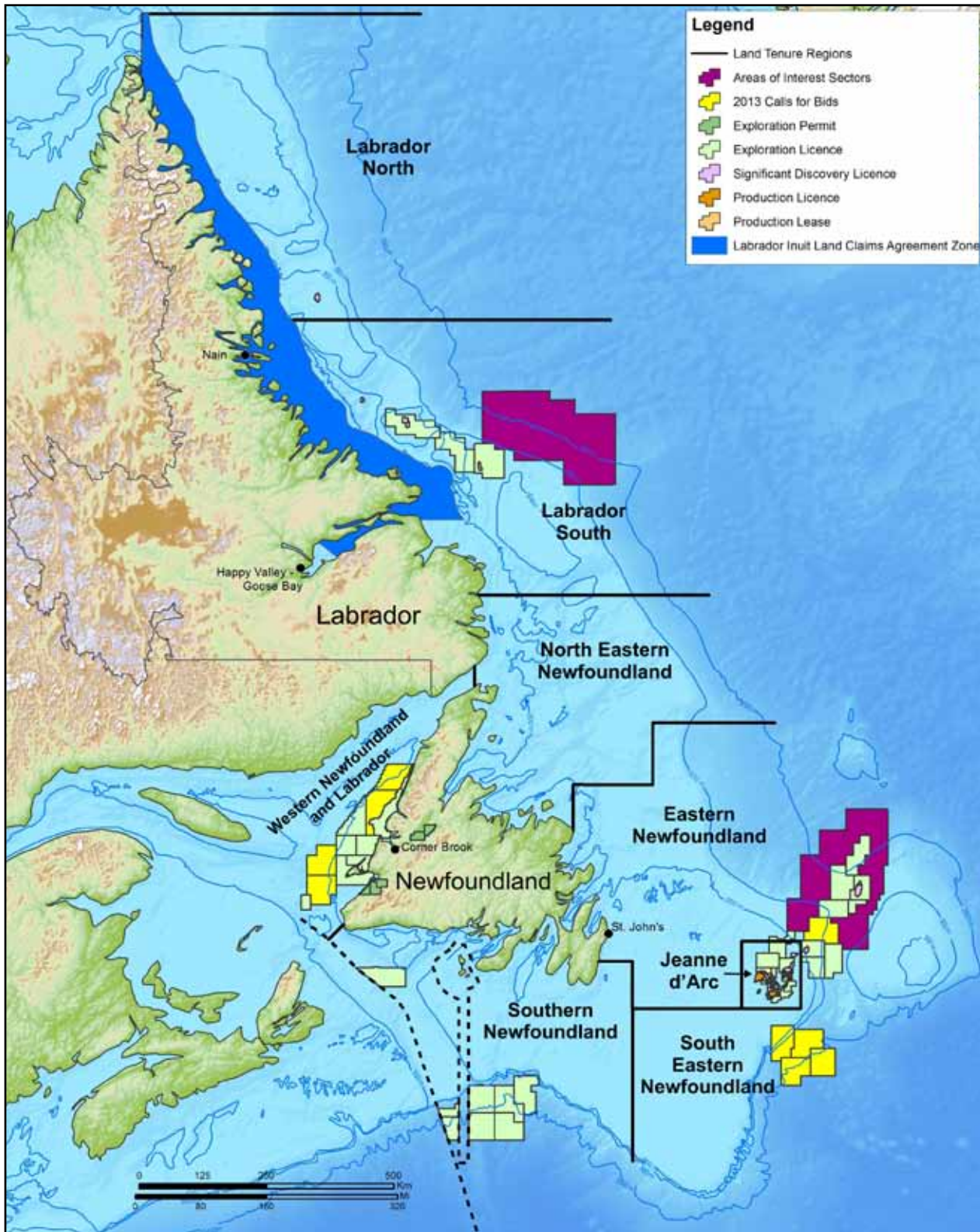
In 2013, the C-NLOPB implemented a new Scheduled Land Tenure System to provide increased lead times for calls for bids in frontier areas. The new system divides the offshore into eight regions based on the level of historical exploration activity. Scheduled licensing rounds will be held in each region 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 19 on page 30 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.

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 above, 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 <http://www.cnlopb.ca/exploration/issuanceprocess.php>

Figure 19 - New Scheduled Land Tenure System Regions



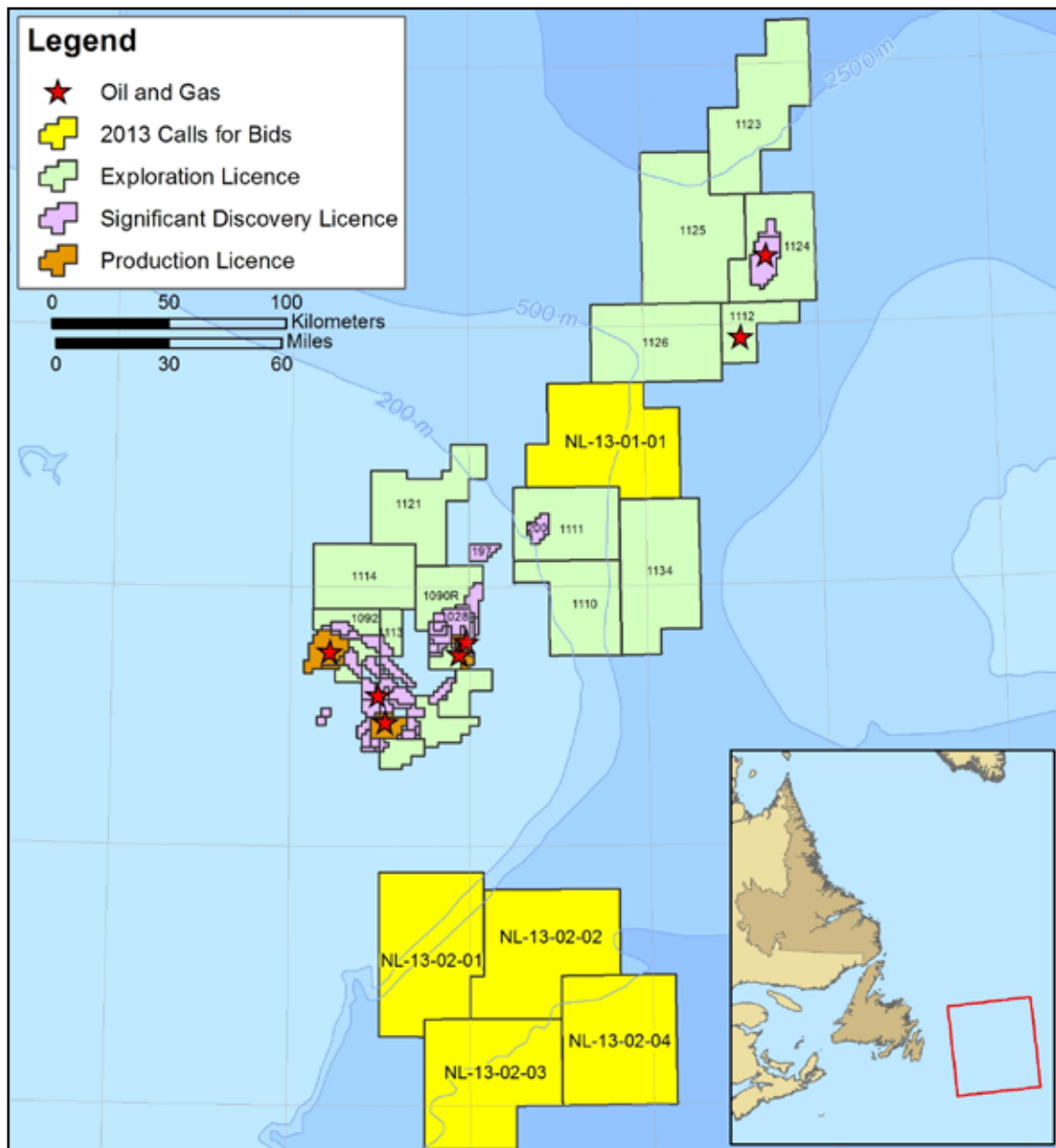
Credit: Department of Natural Resources

3.2 East Coast Offshore - North Grand Banks

Resource Opportunity - 2013 Calls for Bids

There were three Calls for Bids announced in 2013, offering a total of nine parcels of land with a total of 2,409,020 hectares. Two of these calls are located in the east coast offshore area, as shown in Figure 20 below. NL 13-01 consists of a single parcel of land in the Flemish Pass area with a total of 266,139 hectares and NL 13-02 consists of four parcels of land

Figure 20 - East Coast Regional Map



Credit: Department of Natural Resources

in the Carson Basin area with a total of 1,138,399 hectares. A Strategic Environmental Assessment is in process covering the area and the Call for Bids will close at a minimum of 120 days after completion of the assessment.

Exploration Activity - Drilling Programs

Five exploration wells were completed in 2013, resulting in the announcement of three oil discoveries. Statoil Canada, with co-venture partner Husky Energy, drilled the Harpoon 0-85, Bay du Nord C-78 and Bay du Nord C-78Z wells in the Flemish Pass Basin utilizing the West Aquarius drilling rig (shown on the front cover of this report). These wells were in follow up to Statoil's oil discovery at its Mizzen prospect just to the north. At the Bay du Nord prospect, Statoil have estimated recoverable reserves of between 300-600 million barrels of oil. This discovery by Statoil was its largest oil discovery outside of Norway and was also the largest oil discovery worldwide in 2013. Combining the Mizzen and Bay du Nord discoveries, Statoil have estimated recoverable reserves of between 400-800 million barrels of oil and have stated that the region could become a core producing area for the company. With regard to the Harpoon well, Statoil have announced that oil was discovered but have not announced a reserve estimate as further analysis is required.

Also utilizing the West Aquarius drilling rig, Statoil, with co-venture Husky Energy, drilled the Federation K-87 well in the Jeanne d'Arc Basin. Husky has announced that no hydrocarbons were encountered with the well.

In the Orphan Basin, Chevron Canada, with co-venture partners Statoil Canada and Repsol E&P Canada, drilled the Margaree A-49 well utilizing the West Aquarius drilling rig to spud the well and later the Stena Caron drillship to complete the well. No official announcement has been made on drilling results.

Geoscience Programs

Two seismic programs were completed in the offshore east coast region in 2013. 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 seismic program utilizing the M/V Sanco Spirit. A total of 14,353 km of 2D data was collected in the North East - Newfoundland Slope. ExxonMobil conducted 3D/4D seismic in 2013, comprised of a 53,533 km baseline over a portion of the Hebron field, utilizing the M/V Vespucci. Husky conducted a wellsite survey acquiring approximately 864 km of 2D data over Glenwood and North Hebron.

ExxonMobil completed a geotechnical survey in August over a portion of the Hebron field. This work was completed utilizing the M/V Bucentaur. They also completed a 573 km 2D survey in the area of Pool 3 at the Hebron Development utilizing the M/V Strait Hunter. Lastly, two wellsite surveys were completed by Husky Energy in 2013, utilizing the M/V Maersk Challenger.

Land Rights Licencing

The C-NLOPB announced a Call for Nomination (Areas of Interest) in the Eastern Newfoundland Region under the new Scheduled Land Tenure System. Eastern Newfoundland is designated as a high activity area and therefore will follow a two year cycle for awarding new licences. The Call for Nominations closes on March 15, 2014.

Call for Bids NL NL12-02-01 was completed in the Flemish Pass/North Central Ridge area in 2012. The successful bidders were Husky Oil (40%), Suncor Energy (35%) and Repsol E&P Canada (25%) with a bid of \$19,875,875 CAD. Exploration Licence EL 1134 was issued in January 2013, for the parcel.

Exploration Licence EL 1099 held by Husky Oil was at the end of its term during 2013 and the land was returned to the crown. It will be available for nomination by other interested parties in future bidding rounds under the new Scheduled Land Tenure System.

3.3 South Coast Offshore

Land Rights Licencing

Call for Bids NL12-01 was completed in the Laurentian Basin in 2012. Six parcels of land were available for bid and successful bids were received on five of the parcels from Shell Canada Limited totaling \$97 million CAD. Exploration Licences 1129-1133 were issued to Shell in January 2013 (See Figure 21 on page 34 for parcel locations).

Figure #21 - South Coast Regional Map



Credit: Department of Natural Resources

3.4 West Coast Onshore and Offshore

Resource Opportunity - 2013 Calls for Bids

There were three Calls for Bids announced in 2013, offering a total of nine parcels of land with a total of 2,409,020 hectares. One of these calls, NL 13-03, is located offshore western Newfoundland and includes four large parcels totalling slightly in excess of one million hectares. A Strategic Environmental Assessment was completed in the region in May 2013 and the closing date of November 12, 2014, was established for the Call for Bids.

Exploration Activity

Onshore

After obtaining 100% working interest in the onshore exploration permits in the Flat Bay area of Western Newfoundland, Investcan Energy 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 announced they were proceeding through the environmental review process for their two new proposed wells, Thoulet 1 and Thoulet 2.

Offshore

Shoal Point Energy continued to pursue opportunities within the Green Point Formation by drilling the onshore to offshore sidetrack exploration well, Shoal Point 3K-39, on Exploration Licence 1070. On January 8, 2013, Shoal Point Energy submitted an Environmental Assessment Amendment document for EL 1070 with the C-NLOPB. The outcome of the Environmental Assessment will direct future exploration activity.

Regulatory

In November 2013, the Government of Newfoundland and Labrador announced the province would not accept proposals to hydraulically fracture wells onshore or onshore to offshore for exploration until they have had more time to review guidelines and regulations that are in place in other provinces. The province will also assess the geological impact hydraulic fracturing would have on the complex geology in the province. Public consultations are being planned to ensure stakeholders have an opportunity to voice their opinions for such projects.

Land Rights Licencing

Onshore

In 2013, Black Spruce Exploration Corp. purchased 100% ownership of two Exploration Permits 93-103 & 03-105 totalling 159,000 acres onshore Newfoundland within the Deer Lake Basin from Deer Lake Oil and Gas Inc.

Nalcor Energy - Oil and Gas relinquished two onshore Exploration Permits, 03-102 and 03-103 in the Parsons Pond area back to the crown in 2013. Nalcor Energy and partners drilled three exploration wells on the parcels, but found no commercial quantities of oil or gas.

Offshore

In 2012, NWest Energy Corp. sold its interest in offshore exploration licence 1097R to Shoal Point Energy Ltd. Terms of the deal included Shoal Point Energy posting a \$1.0 million CAD drilling deposit with C-NLOPB to extend Term 1 of the exploration licence until January 15, 2013. In January 2013, Shoal Point Energy struck a farm-out agreement with Black Spruce Exploration on three of its exploration licences, 1070, 1120, and 1097R. Exploration Licence 1097R was at the end its primary term and required an extension from the C-NLOPB for the licence to stay in effect. Shoal Point was not able to secure an extension from C-NLOPB and the land parcel reverted back to crown reserve. It will be available for nomination by other interested parties in future bidding rounds under the new Scheduled Land Tenure System.

In 2013, Black Spruce Exploration Corp. announced several purchase and farm-in agreements with existing offshore licence holders in Western Newfoundland. In April 2013, Black Spruce Exploration Corp. announced that it had acquired 100% working interest in three offshore Exploration Licences (1120, 1127, 1128) from Ptarmigan Energy Inc. Black Spruce Exploration also announced that it had signed a farm-in agreement with Shoal Point Energy Limited to earn a 60% working interest in Shoal Point Energy Ltd's land interests in the shallow rights to ELs 1070 and 1120. Lastly, as part of the farm-in agreement detailed in Section 2.6 with Enegi, Black Spruce can earn a 60% working interest in EL's 1116 and 1070 by drilling seven wells.

In September 2013, the C-NLOPB issued two Significant Discovery Licences (1051 and 1052) based on the Suncor et al Ballicatters M-96Z exploration well and drill stem test results. Based on the C-NLOPB's interpretation of the data, the Board has estimated that the Ballicatters discovery contains recoverable resources of 1143 BCF of gas with 21 million barrels of natural gas liquids.

3.5 Labrador Offshore

Land Rights Licencing

The C-NLOPB announced a Call for Nomination (Areas of Interest) in the Labrador South Region under the new Scheduled Land Tenure System (See section 3.0 of this report on page 29 for details on the new system). Labrador South is designated as a low activity area and therefore will follow a four year cycle for awarding new licences. The Call for Nominations closes on March 15, 2014.

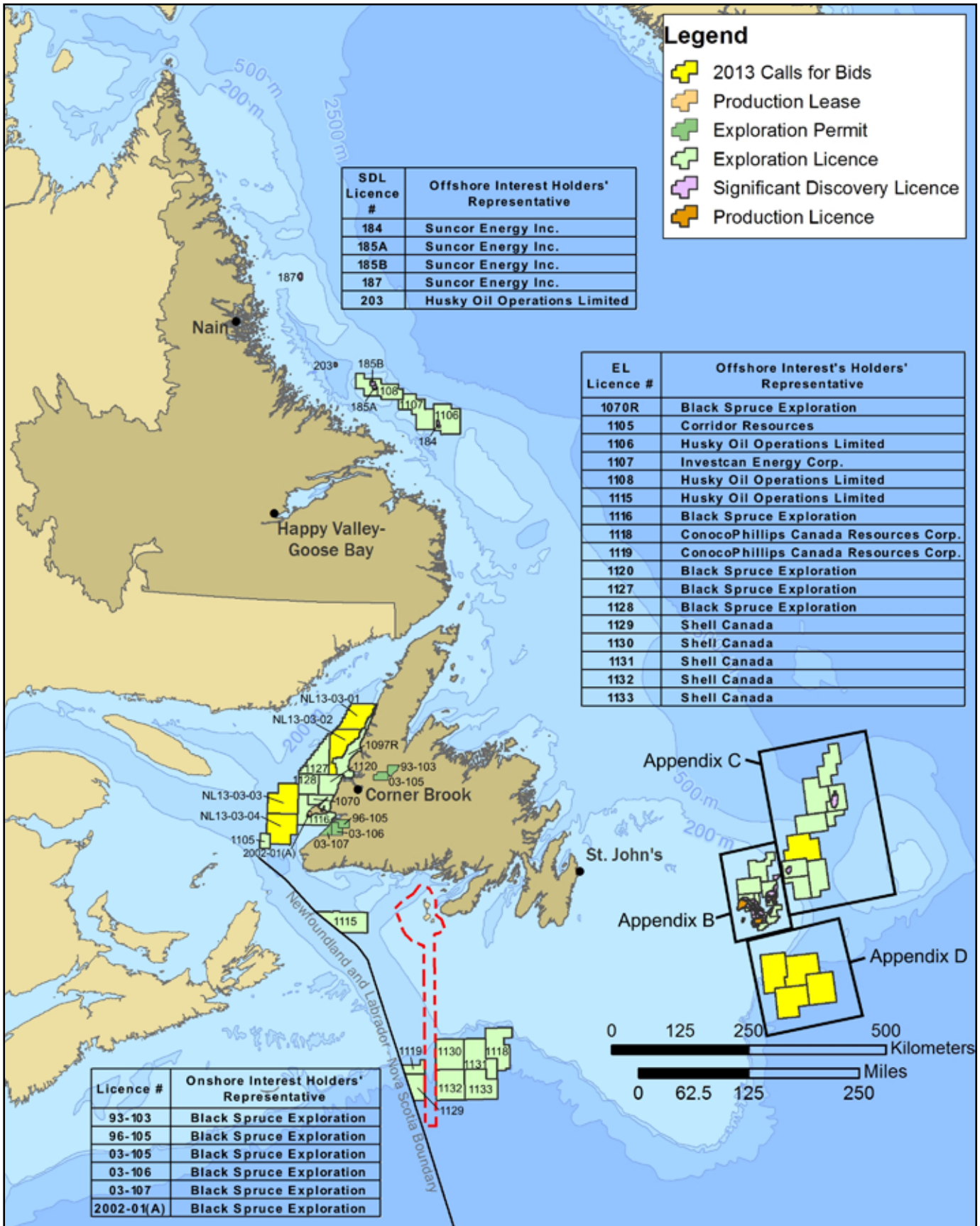
Late in 2013, Chevron Canada Limited relinquished EL 1109 covering a large land parcel in the Hopedale Basin offshore Labrador. The land was returned to the crown and will be available for nomination by other interested parties in future bidding rounds under the new Scheduled Land Tenure System.

Geoscience Programs

In 2013 there were two 2D seismic programs completed in the offshore Labrador area. 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 utilizing the M/V Sanco Spirit. The MV Sanco Spirit collected an additional 2,938 line kilometers of 2D data on the Labrador Shelf.

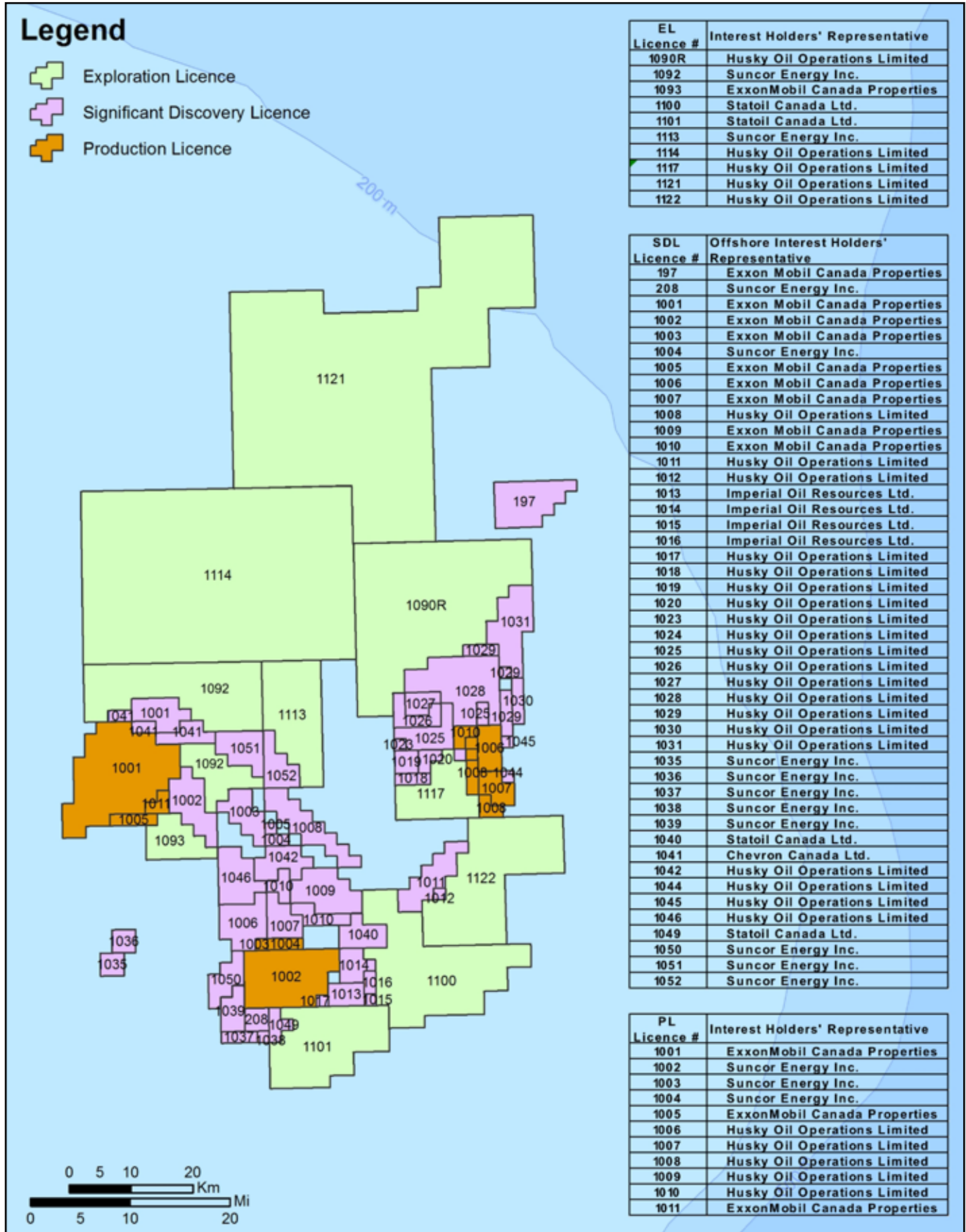
The second seismic program conducted in this area during 2013 was by GXT Technology. The program collected 6574.7 line kilometers of 2D data utilizing the M/V Discoverer.

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



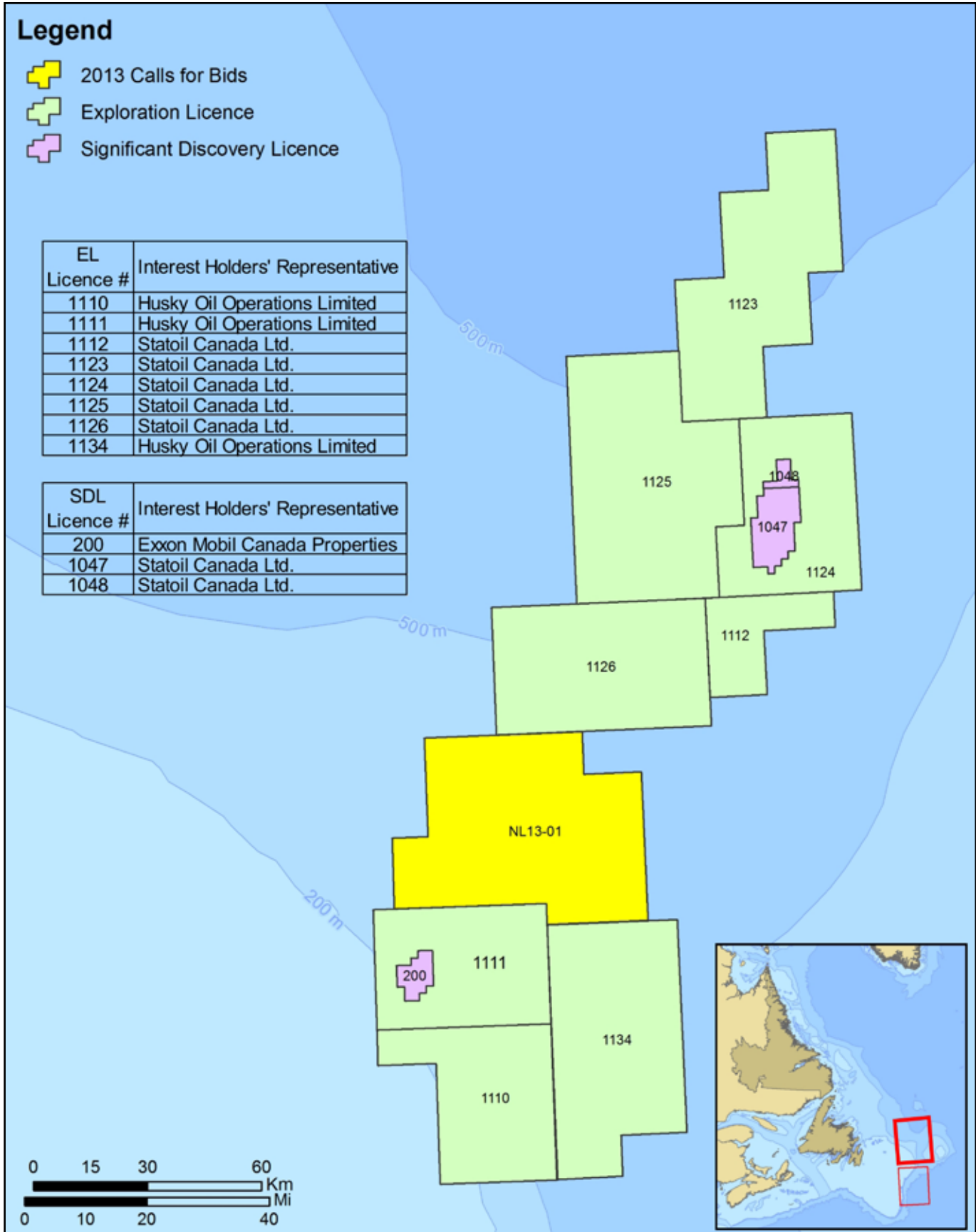
Credit: Department of Natural Resources

Appendix B - Licence Holders Jeanne d'Arc Basin Region



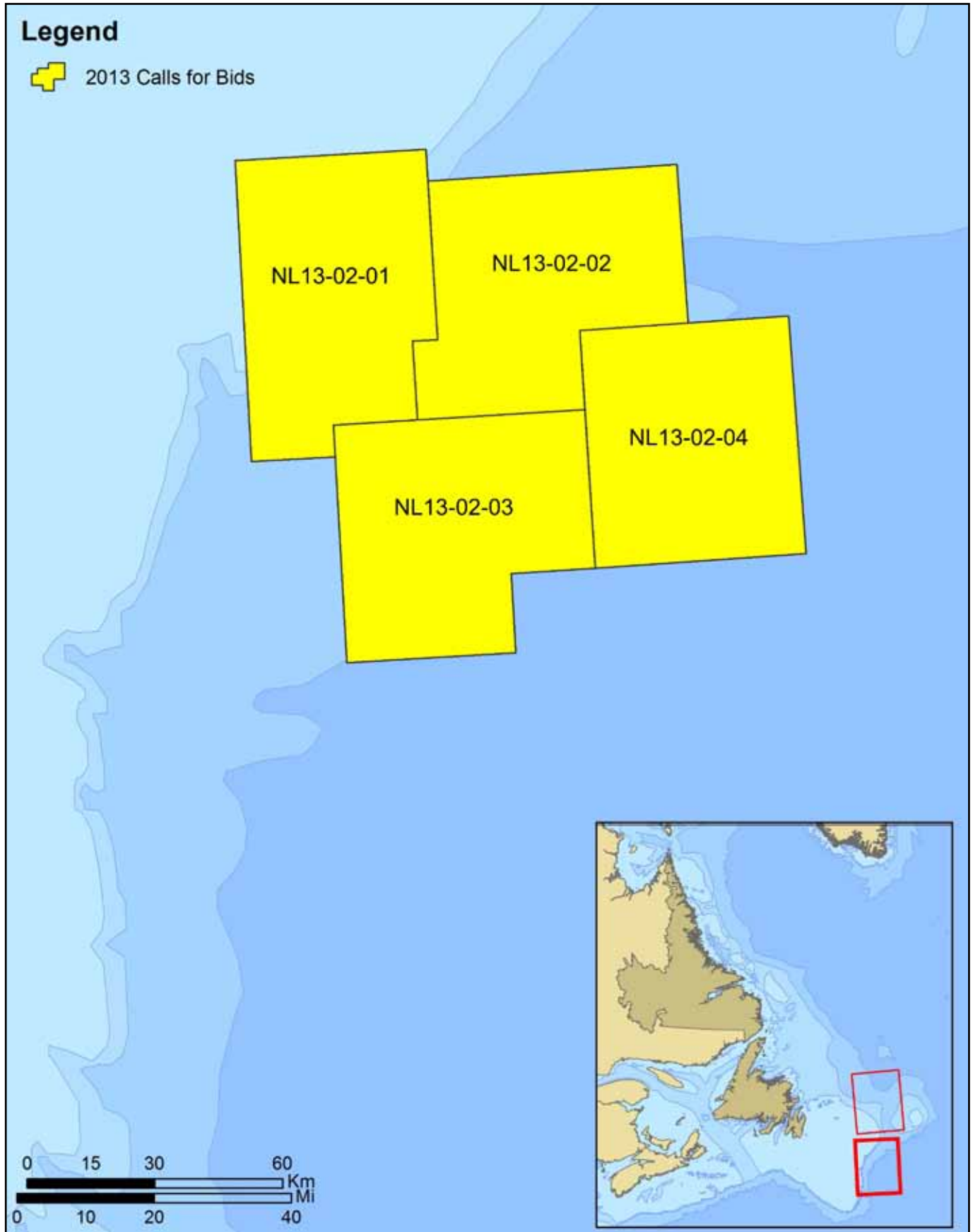
Credit: Department of Natural Resources

Appendix C - Licence Holders Eastern Newfoundland Region



Credit: Department of Natural Resources

Appendix D - NL13-01 Calls for Bids Carson Basin



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