Petroleum Development

Activity Report

2012

Newfoundland Labrador

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Department of Natural Resources
Petroleum Development
Activity Report - 2012

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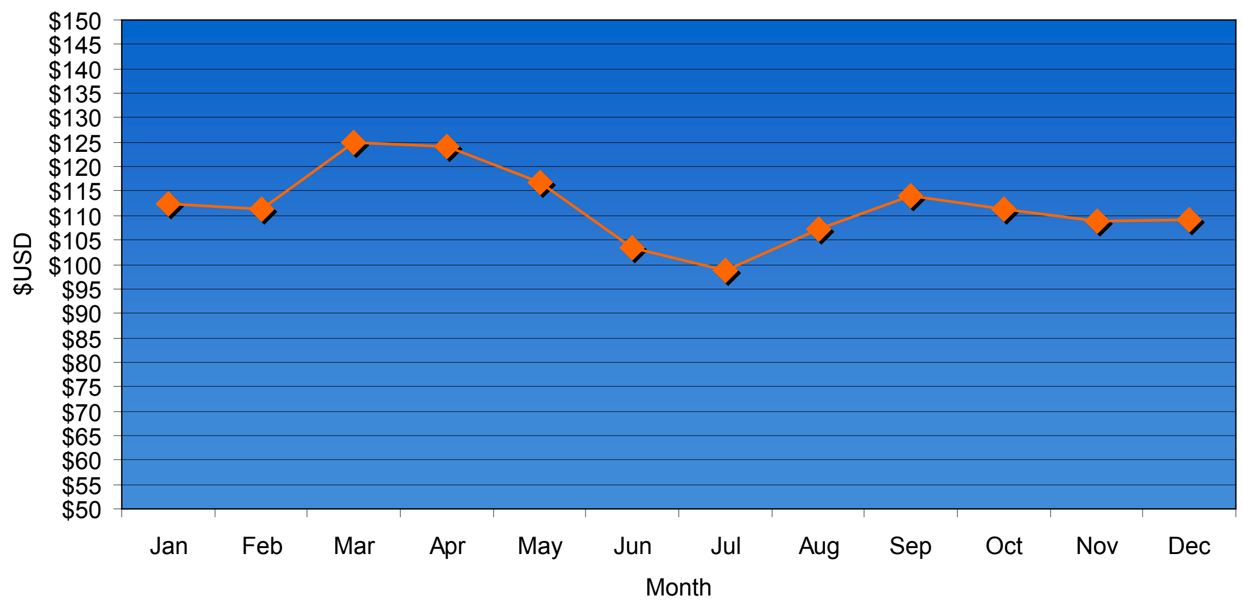
1.0 Introduction

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 15 years. During that time, the province's four producing fields, Hibernia, Terra Nova, White Rose and North Amethyst, have produced more than 1.3 billion barrels of oil This represents approximately 10% of Canada's crude output and 30% of its light crude production.

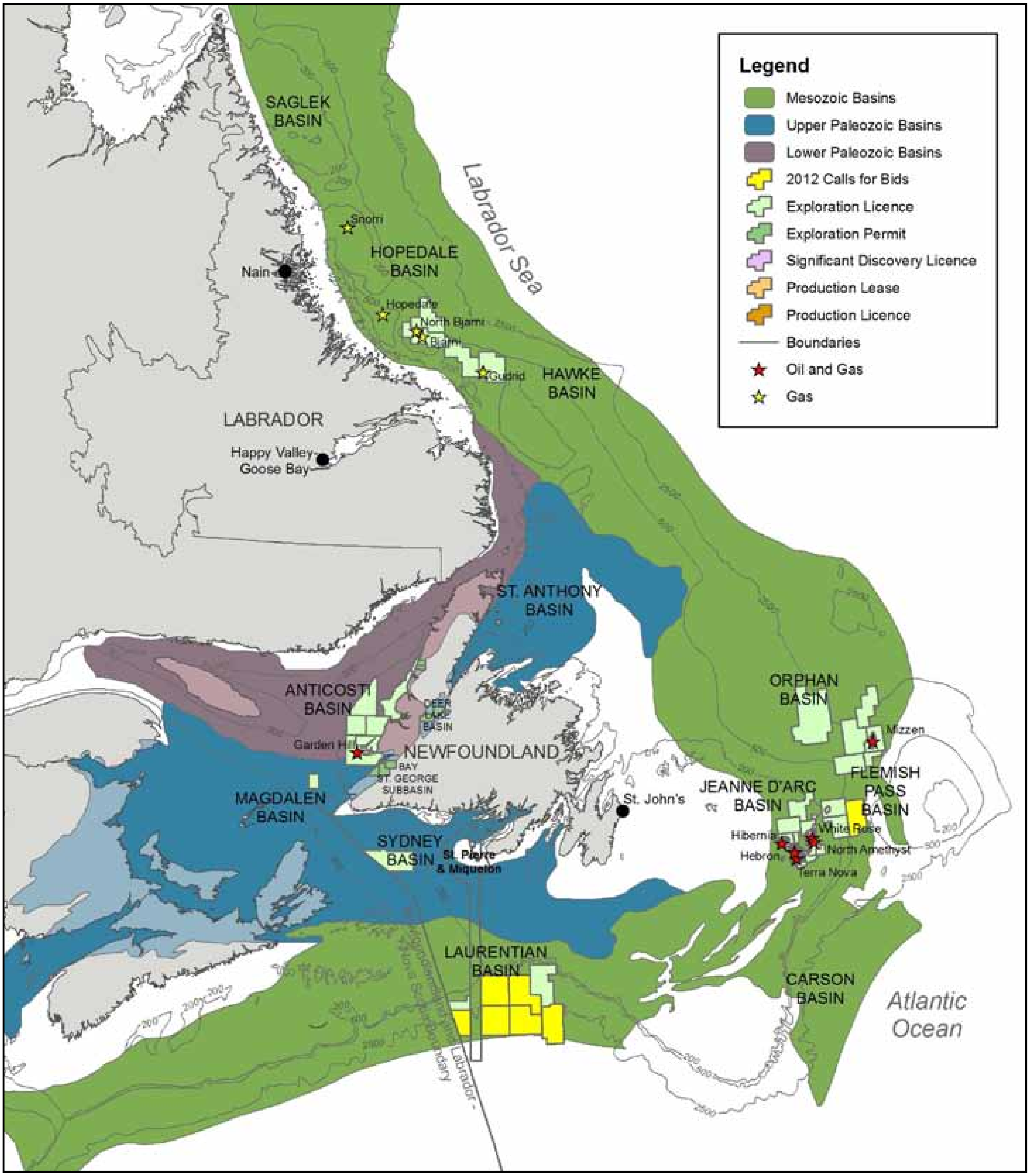
Total production in 2012 was 72.2 million barrels of oil. This level of annual production was significantly lower than previous years mainly due to extended off station maintenance and upgrade programs at three of the four producing fields. The price of oil, however, remained high, as evidenced by Figure 1 below, and royalties on production continued to be the largest single source of revenue (approximately 30%) for the provincial treasury.

Figure #1 - Weekly Europe Brent Spot Price FOB 2012 (Dollars per Barrel)



Currently Newfoundland and Labrador has less than 10% of prospective onshore and offshore land held under license. The total potential acreage, as outlined on the Sedimentary Basins Map 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 Provincial Government of Newfoundland and Labrador has sole management authority.

The C-NLOPB issues land rights in three different classes: exploration licenses, significant discovery licenses and production licenses. As of December 31, 2012, the C-NLOPB had issued 33 exploration licenses, 52 significant discovery licenses and 11 production licenses (See Appendices A and B). During 2012, successful work expenditure bids totaling $116,875,875 were received on Calls for Bids conducted in the Laurentian Basin and the Flemish Pass Basin/Central Ridge areas. The 2012 Calls for Bids generated the second highest level of work commitments since 2007. Six new exploration licenses will be issued on these land parcels early in 2013 when all relevant terms and conditions are met. The total outstanding work commitments on existing exploration licenses was approximately $1.2 billion as of December 31, 2012.

There have been a total of 381 wells spud in the province's offshore area as of December 31, 2012. They comprise 179 development wells, 52 delineation wells and 150 exploration wells. The exploration and delineation wells have resulted in 51 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 is now reporting recoverable reserve/resource estimates for Newfoundland and Labrador's offshore basins at 3.5 billion barrels of oil and 11.05 trillion cubic feet of natural gas as detailed in Table 1 on page 4. Geoscience data indicates that a further 6 billion barrels of oil and 60 trillion cubic feet of natural gas remain undiscovered.

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 90 wells spud onshore and as of December 31, 2012 the province had seven exploration permits and one production lease on record. The exploration permits onshore, encompassing approximately 187,303 hectares, have been issued in three general areas in western Newfoundland: Flat Bay, Deer Lake and Parsons Pond. 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.

Table #1 Petroleum Reserves[1] and Resources[2] Newfoundland Offshore Area

Field	Oil $10^6 m^3$	Oil million bbls	Gas $10^9 m^3$	Gas billion cu. ft.	NGLs[3] $10^6 m^3$	NGLs[3] million bbls
Grand Banks						
Reserves						
Hibernia	221.9	1395				
Hebron	112	707				
Terra Nova	66.6	419				
Whiterose[4]	36.3	229				
North Amethyst	10.8	68				
Resources						
Hibernia			55.9	1984	35.8	210
Terra Nova	13.7	86	1.5	53	0.6	4
Whiterose[5]	12.1	77	85.3	3023	15.3	96
North Amethyst			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
Sub-Total	**557.3**	**3510**	**191.9**	**6804**	**60.3**	**364**
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	**557.3**	**3510**	**311.5**	**11048**	**80.2**	**487**
Produced[6]	**208.6**	**1312**	**0**	**0**	**0**	**0**
Remaining	**348.7**	**2198**	**311.5**	**11048**	**80.2**	**487**

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, North Amethyst and Hebron 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, NGLs[3], 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 contain South Avalon Pool and Southern Extension Pool

5 White Rose Resources contains West Avalon Pool, North Avalon Pool and Hibernia Reservoir

Newfoundland and Labrador's prospective onshore and offshore basins continued to experience significant exploration interest in 2012. The TGS NOPEC Geophysical Company/ Petroleum Geo-Services Inc. led consortium, Multi-Klient Invest ASA, completed its major 22,000 line kilometer 2D seismic program offshore Labrador and commenced an extensional 20,000 line kilometer 2D survey offshore the island portion of the province. When completed, these combined programs will be one of the largest modern 2D datasets compiled for one area. Statoil also continued with seismic work in the Flemish Pass Basin. Following a 3D program in 2011 Statoil completed another extensive 3D program in 2012 covering 5,773 km^2 prior to commencing a drilling program in the area in 2013.

Two exploration wells were spud in Newfoundland and Labrador's offshore waters in 2012. On the west coast 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. Shoal Point have announced that hydrocarbons were encountered and they plan to return in 2013 to drill a further appraisal well and perform the necessary tests for application for a Significant Discovery License from the C-NLOPB. Off the east coast, Husky Energy spud the Searcher C-87 exploration well in the Jeanne d'Arc Basin on August 8, 2012 utilizing the drilling rig, Henry Goodrich. Due to mechanical issues with the rig, drilling operations were suspended in late August, 2012 and the rig was moved off location for repairs. On November 26, 2012 the drilling rig GSF Grand Banks returned to the site to complete the well and as of December 31, 2012 drilling operations were ongoing.

Major development work continued in 2012 on new offshore field developments. ExxonMobil received approval for its development application from the C-NLOPB for the Hebron project and continued to advance the project by moving from the Front End Engineering and Design (FEED) Phase to the Detailed Engineering Phase of the project. Contracts with existing contractors, Worley Parsons and Kiewit Kvaerner Contractors in the FEED Phase were extended for the Detailed Engineering Phase. The capital cost of the total program is estimated at $14 billion. Site preparations for the construction of the gravity based structure have commenced and first oil is expected in 2017.

Husky Energy continued to advance work on development alternatives for the western portion of the White Rose field in 2012. One of the options under consideration includes the construction of a wellhead concrete gravity structure that would have the ability to drill wells in the western portion, as well as other parts of the White Rose field. A contract for the early stage engineering and design has been awarded to Arup Canada and Husky has secured an option to lease land in Argentia, NL as a site for the construction of the concrete gravity structure. A decision on which development option is expected in 2013.

Major off station repair and maintenance programs were completed on equipment utilized in Newfoundland and Labrador which had a major impact on exploration and production during the year. In 2012, the two main drilling rigs that have been used in exploration drilling programs in the Newfoundland and Labrador offshore area were taken out of service for extended periods of time to undergo repairs and upgrades. The drilling rig GSF Grand Banks was out of service for the first two months of the year as it was undergoing repairs and maintenance at a shipyard in Halifax, Nova Scotia. Late in 2011, the drilling rig Henry Goodrich was transferred to Signal International's shipyard in Pascagoula, Mississippi for repairs and upgrades. The rig remained at the yard until May, 2012 when it was relocated back to Newfoundland and Labrador. In August, 2012, the rig was again taken out of service due to mechanical issues and as of December 31, 2012 was still undergoing repairs and testing.

With regard to production, Newfoundland and Labrador's annual production in 2012 was approximately 25% lower than levels achieved the previous year. The main reason for the production drop was extended maintenance and upgrade programs on the Province's three production installations. The Hibernia platform was off production for a period of three weeks during the summer to complete upgrades and install equipment to facilitate commissioning of the Hibernia South Extension. The Terra Nova Floating Storage, Production and Offloading (FPSO) was taken off station for a period of approximately 6 months to complete upgrades and install new subsea infrastructure. Lastly the SeaRose FPSO was due for a major refit and was transferred to a drydock in the United Kingdom for a comprehensive maintenance program.

It is expected that 2013 will be an excellent year for the oil and gas industry in the province. Production should return to normal levels as the 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 as well as the arrival of two other drilling units, the West Aquarius semi-submersible drilling rig and the Stena Caron drillship. The West Aquarius will be used by Statoil for their drilling program in the Flemish Pass and Jeanne d'Arc basins and the Stena Caron will drill another exploration well in the Orphan Basin.

2.0 Field Development Summary

2.1 Hibernia - Main Field

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%

The Hibernia field, the first field development in the Newfoundland and Labrador 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.

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 Canada-Newfoundland and Labrador Offshore Petroleum Board (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.

Hibernia GBS

During the 2012 three week turnaround, several large upgrade and maintenance projects were completed at the Hibernia platform. Firstly, final hook up and commissioning of equipment to assist with gas lift, which was installed in the 2011 turnaround, was completed. Secondly, additional life boat capacity was installed on the platform to meet new safety standards. And lastly, equipment to connect the manifold valves required for the Hibernia South Extension (See section 2.1.2) subsea infrastructure was installed.

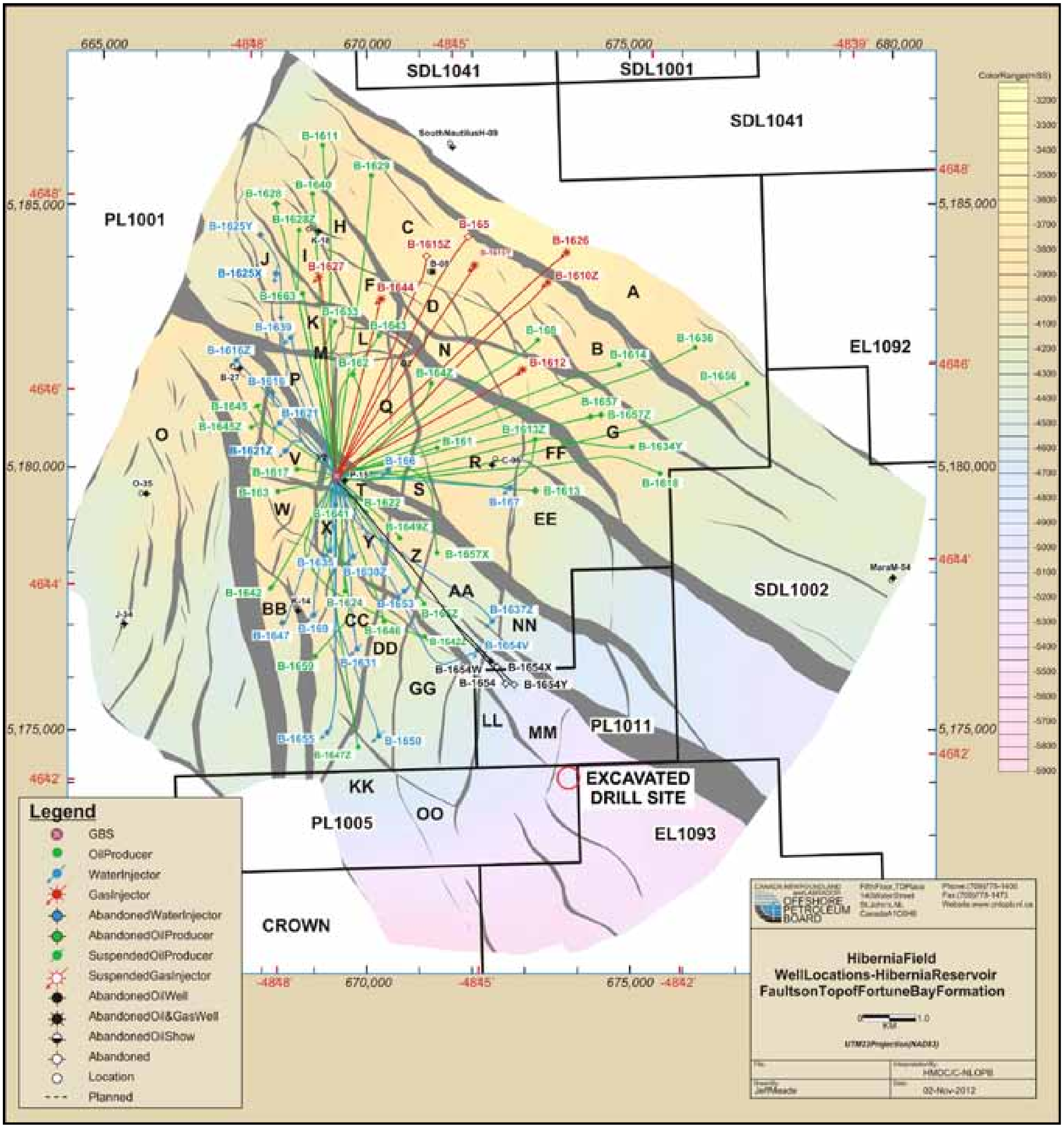
As of December 31, 2012, Hibernia was operating with 60 development wells as shown in Figure 3 on page 9. They include 36 oil producers, 18 water injectors and 6 gas injectors. Hibernia produced 47.8 million barrels of oil during 2012 for an average daily production of 131,060 bopd. Cumulative oil production to December 31, 2012 was 827.1 million barrels representing 59.3% of the total current reserve estimate. Oil production in 2012 was lower than that achieved in 2011 due to normal production declines as well as the extended maintenance shutdown as previously described.

In June 2009 it was announced that the Hibernia project had reached payout; the time at which 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 located on page 11 shows the two sections within the Hibernia Southern Extension.

A Memorandum of Understanding (MOU) 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.

Figure #3 - Hibernia Field Well Locations



2.1.1 Hibernia Southern Extension - AA Block

The Hibernia AA Block as shown in Figure 4 on page 11 includes the AA1 and AA2 blocks contained in the Hibernia reservoir within Production License PL-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).

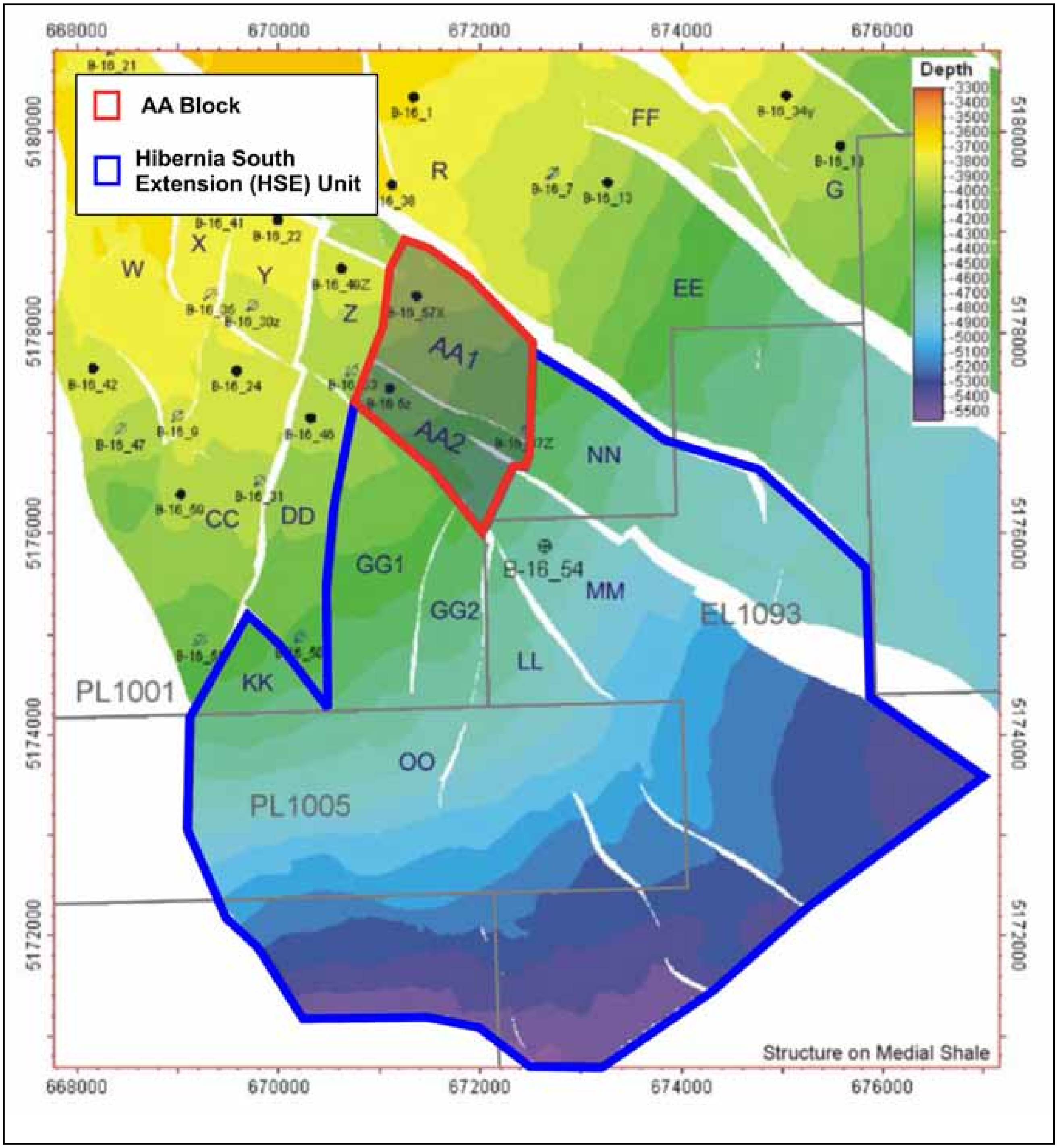
The C-NLOPB has assigned a recoverable reserve estimate of 48 million barrels of oil for the AA Block. Note that these reserves are included in the overall Hibernia recoverable reserve estimate of 1.395 billion barrels of oil mentioned previously in Section 2.1 - Hibernia - Main Field. Production from 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 2012 oil production from these two wells totalled 6.24 million barrels giving an average daily production of 17,088 barrels. The total cumulative production to December 31, 2012 for the AA Block was 28.5 million barrels of oil representing 59.4% 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 on page 7. 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 included 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



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 Licenses 1001 and 1005, and Exploration License 1093, were granted the right to develop the Hibernia reservoir located in the Hibernia South Extension (HSE) Unit as shown in Figure 4 on page 11. The additional area in the amendment includes the GG, KK, LL, MM, NN and possibly the OO fault blocks. In 2012, the portions of the HSE Unit held under Exploration License 1093 that are to be developed were transferred to Production License 1011 with the ownership positions as shown on the chart on page 13.

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 in excess of $1.1 billion of the total.

The approved development plan for the HSE Unit consists of drilling 10 wells comprising 5 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 2012, oil production from these two wells totalled 1.6 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, 2012 was 3.0 million barrels of oil which represents 2% 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 (shown on the front cover of this report). This drill centre will be located approximately 7 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 7 kilometer long flowlines and umbilicals connecting the water injectors to the platform. This equipment is scheduled for delivery in 2013.

Late in 2012 the ultra-deepwater semi-submersible drilling rig, West Aquarius, arrived in Newfoundland. The drilling rig will be used to drill the water injector wells commencing late in 2013 and continuing into 2014. Prior to drilling the water injection wells for the HSE project, the rig will be used by Statoil for exploration drilling programs in various basins off the east coast commencing early in 2013, once certification and safety inspections are complete.

The signing of the Hibernia South Development Agreement on February 16, 2010 with the Provincial Government, 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 licensed under the original Production License PL1001 and land licensed under both the Production License PL-1005 and Exploration License EL-1093 (now Production License 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 licensed 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 graphs.

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

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

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

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.

The latest recoverable reserve/resource estimate for the Terra Nova field, released in 2012, includes 505 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.

As of December 31, 2012, Terra Nova was operating with a total of 28 development wells. They consist of 16 oil producers, 9 water injectors and 3 gas injectors. During 2012 the field produced 8.5 million barrels of oil equating to an annualized daily production of 23,210 bopd. Cumulative field production to the end of 2012 was 335.6 million barrels of oil which represents 80.0% of the current recoverable reserve estimate.

Terra Nova FPSO in Marystown, Summer 2012

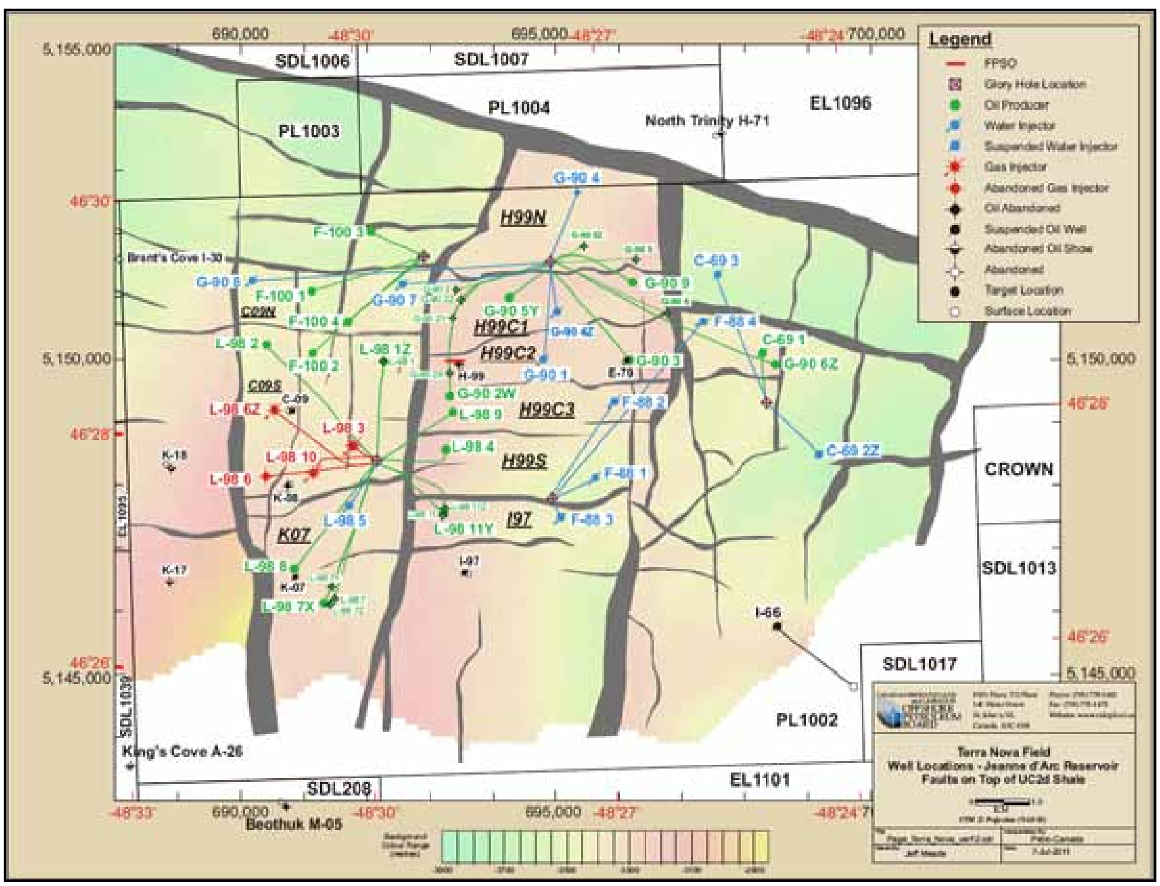
Production at the Terra Nova field was significantly lower in 2012 than previous years due to an extended shutdown of the Terra Nova FPSO for planned maintenance and upgrades. On June 8, 2012, the production shutdown commenced at the field site in preparation of the relocation of the vessel to Peter Kiewit's repair and fabrication facility in Marystown, NL.

Work completed at the site included replacement of the water injection swivel, refurbishment of the main power generators as well as other routine maintenance. While docked, equipment was also installed on the FPSO to handle hydrogen sulfide (sour gas) which was discovered in 2010 in several producing wells. The vessel arrived in Marystown on June 26, 2012 and returned to the offshore field location on October 10, 2012.

While off location, Suncor also carried out extensive work on the subsea infrastructure at the field site which was also affected by the presence of hydrogen sulfide. Subsea 7 was contracted to install replacements for nine 300 meter risers and approximately 20 kilometers of flexible flowlines. In addition, Suncor installed a new well flow base in the southwest drill center which provides more drill slots to access untapped sections of the reservoir.

Commissioning of the new equipment took longer than expected and during testing it was determined that one of the risers was found to be faulty and subseqently a flowline did not pass commissioning. The unit was removed and a replacement is planned for installation in 2013. The first of three drill centers was brought on line on December 9, 2012 with the other two planned for start up early in 2013.

Figure #5 - Terra Nova Field Well Locations



2.3 White Rose Field

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

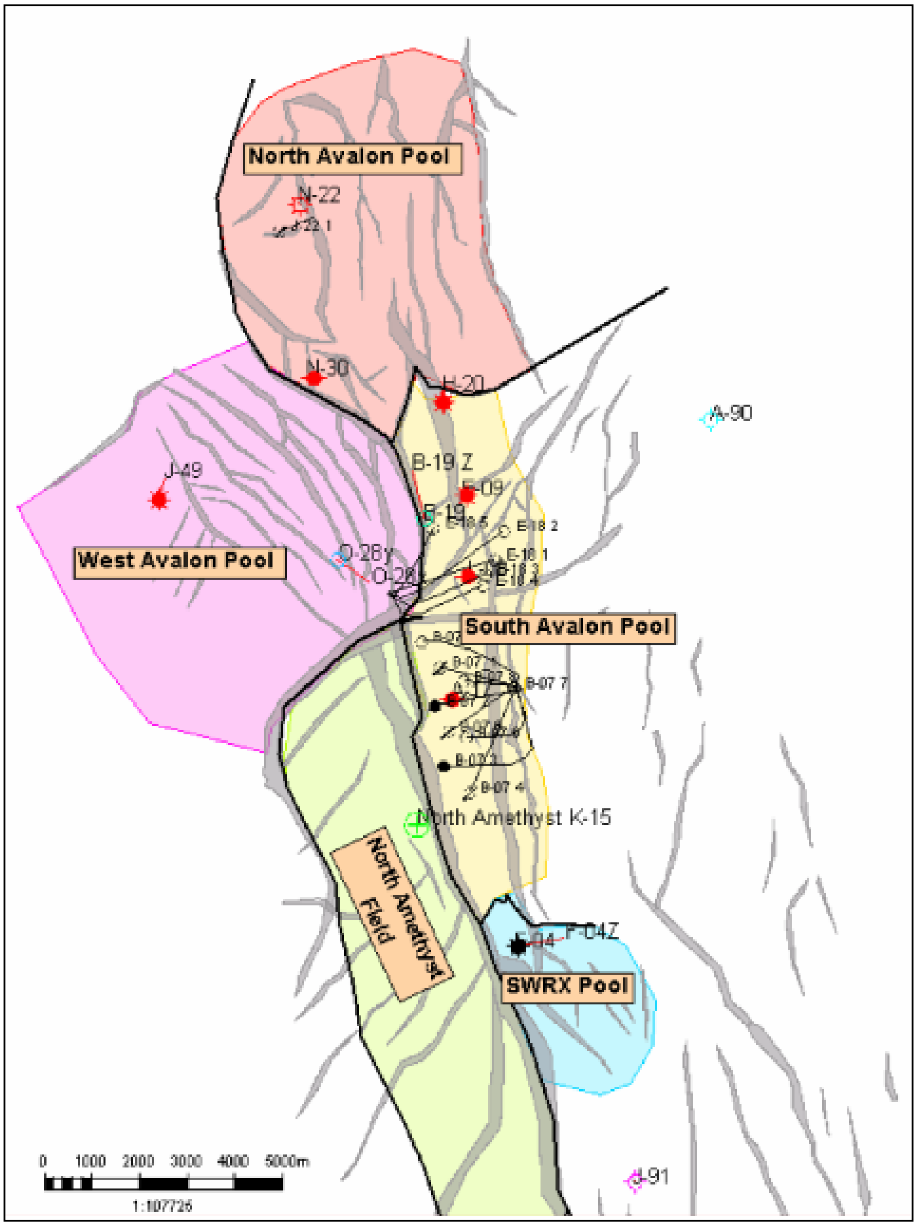
In 1984 Husky Energy discovered the White Rose field by drilling the White Rose N-22 exploration well in water depths of approximately 120 meters. The discovery well tested at 900 barrels of oil per day, 25 million cubic feet of natural gas and 840 barrels per day of condensate. The field consists of a principal 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.

The C-NLOPB has assigned recoverable reserve/resource estimates for the field at 306 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 6 on page 17 shows the location of the various pools. These estimates however do not include recoverable resource estimates of 68 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.

White Rose FPSO SeaRose in Belfast Dry Dock, Summer 2012

Oil production from the White Rose field in 2012 was significantly reduced from previous years due to an extended maintenance shutdown. This shutdown entailed the SeaRose FPSO travelling to the Harland and Wolff dry dock in Northern Ireland. This maintenance program was the first time that the vessel had left the site for repairs since production began at the field in 2005. The FPSO ceased production on May 8, 2012 in preparation for the 3,500 kilometer journey. Repairs to the vessel included work on the engine and propulsion system, repainting the exterior hull and fire equipment improvements. Prior to travelling to Ireland, the vessel docked in Conception Bay, NL for the installation of a 260 ton, 23 metre cover plate on the bottom of the vessel where the subsea production equipment is connected. The maintenance program was completed slightly ahead of the 18 week scheduled and production recommenced on August 13, 2012.

Figure #6 - White Rose Development Area



Oil production in 2012 from the main White Rose field and the West White Rose pilot program discussed in section 2.3.1 totaled 9.0 million barrels oil which equates to an annualized daily production of 24,560 barrels of oil. Total cumulative production as of December 31, 2012 was 174.4 million barrels which represents 57.2% of the total reserve estimate. The main field and the West White Rose pilot program are being developed utilizing 23 development wells consisting of 9 production, 11 water injectors and 3 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 - Oil and Gas, 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. Note that 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 South White Rose Extension and the West Avalon Pool. Details on these two new projects are outlined in Sections 2.3.1 and 2.3.2 respectively.

Late in 2012, Husky Energy announced that it had reached an agreement with Seadrill Limited for the long term lease of the semi-submersible drilling rig West Mira. The West Mira 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 licenses.

Figure #7 - West Mira, 6th generation semi-submersible

2.3.1 West White Rose Extension

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

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 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. As of December 31, 2012, the pilot scheme had produced a total of 2.5 million barrels of oil. 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 have 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 2012, Husky Energy filed a project description outlining two development options under consideration for development of the West White Rose area. They include a subsea drill centre tieback and a concrete gravity based wellhead platform. The subsea drill centre op-

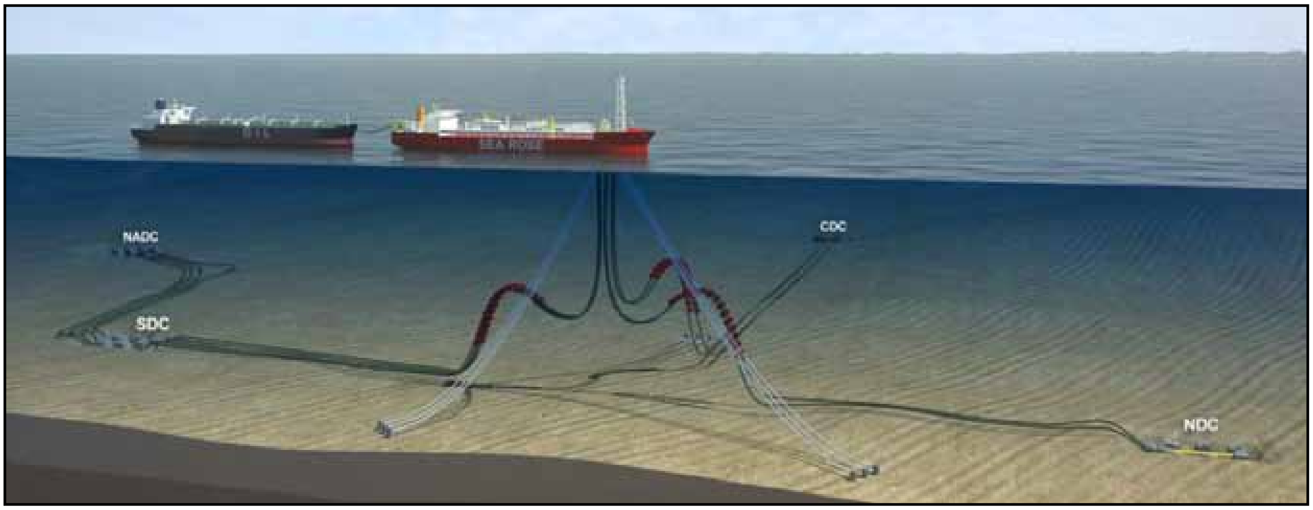


Figure #8 - White Rose Field Layout 2012

tion will include construction of a West White Rose drill centre as well as up to three additional subsea drill centres. Drilling of the production wells connected to the drill centers will be done from a mobile offshore drilling unit. The new subsea drilling units will then be tied back to the SeaRose FPSO through existing infrastructure.

The second option is the construction of wellhead platform as well as up to three future subsea drill centres. 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.

Husky Energy engaged Arup Canada Inc. to complete the pre-decision work and then subsequently hired them to complete the front end engineering and design work. This work is expected to be completed by mid to late 2013 and then a final decision will be made about which development option the company will undertake. Environmental approval has already been secured for the subsea option and the company has registered the wellhead platform option for an environmental assessment and a decision for it is expected later in 2013. As part of the environmental assessment process for the wellhead option, Husky Energy has proposed that the 172,000 ton concrete gravity structure for the wellhead platform will be constructed at a purpose-built graving dock in Argentia, NL.

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 Significant Discovery Licenses 1043 and 1044. The plan called for a subsea tie-back to the SeaRose FPSO through the existing southern glory hole as well as a new glory hole to be constructed approximately 4 kilometers further south. Although approval was granted by the C-NLOPB, the co-venture partners have not yet proceeded with development. 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 have been developing 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 South White Rose Extension area and the drilling of six development wells that will be attached to the new drill centre. Four of the six development wells, consisting of two oil producers, one water injector and one gas injector, will be used to produce oil from the South White Rose Extension area. The balance of the two development wells, consisting of an oil producer and a gas injector, will be drilled in the South Avalon Terrace in the main White Rose field. It is expected that these development wells will produce a total of 33 million barrels of oil with 24 coming from the South White Rose Extension area and 9 million barrels of oil from the South Avalon Terrace area of the main field. The total cost of the project is $1.2 billion CAD including $590 million for drilling and completions and $495 million for subsea infrastructure.

In advance of approval of the development plan amendment, Husky Energy has commenced work on the project with the dredging of the drill center glory hole. The work was completed in 2012 utilizing the 223 meter Cristobal Colon, one of the world's largest dredging vessels.

Cristobal Colon docked in St. John's Harbour

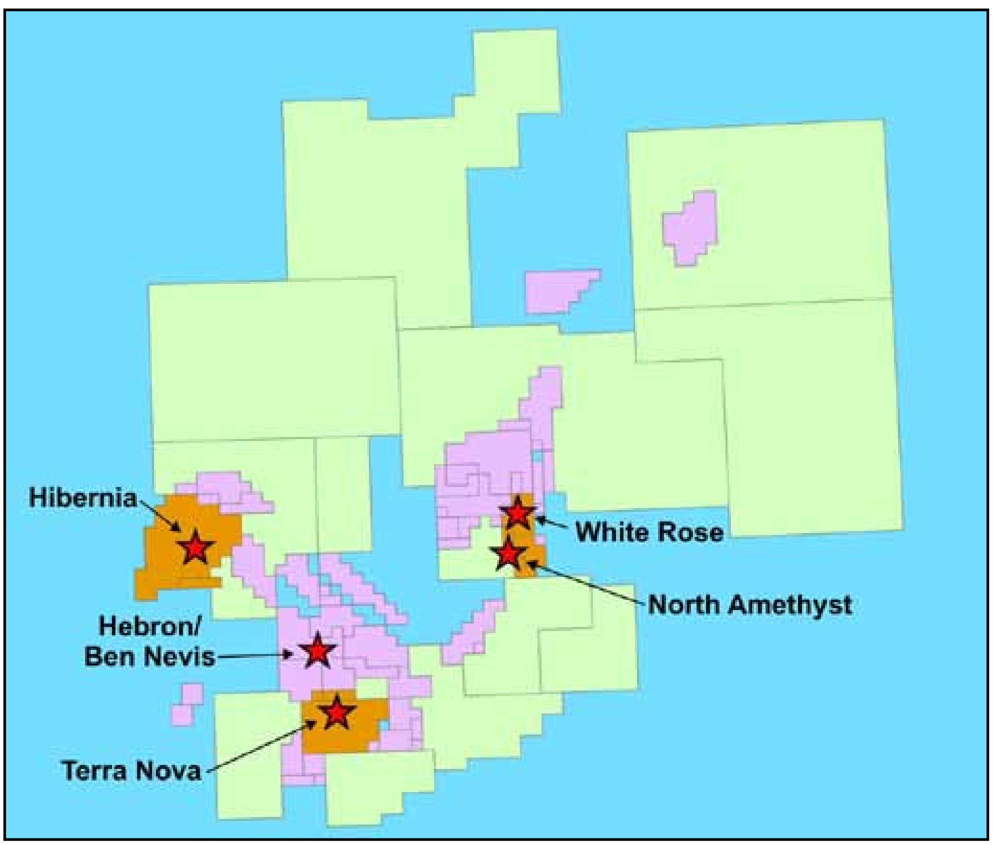
2.4 North Amethyst Field

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

The North Amethyst field was the first of the satellite pools to be developed in the Jeanne d'Arc Basin. It was identified by exploratory drilling in 2006 and the C-NLOPB reports recoverable reserve/resource estimates of 68 million barrels of oil and 315 billion cubic feet of natural gas in the Ben Nevis/Avalon Formation. In 2009, Husky Energy announced that additional resources were discovered at North Amethyst in the lower Hibernia Formation, totalling approximately 60 million barrels of original oil in place. Further details on these new resources have not been released and the C-NLOPB have not yet completed an analysis of the new discovery for resource estimates.

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 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 6 kilometers away. Initial production from North Amethyst occurred on May 31, 2010 from the oil well G-25 2.

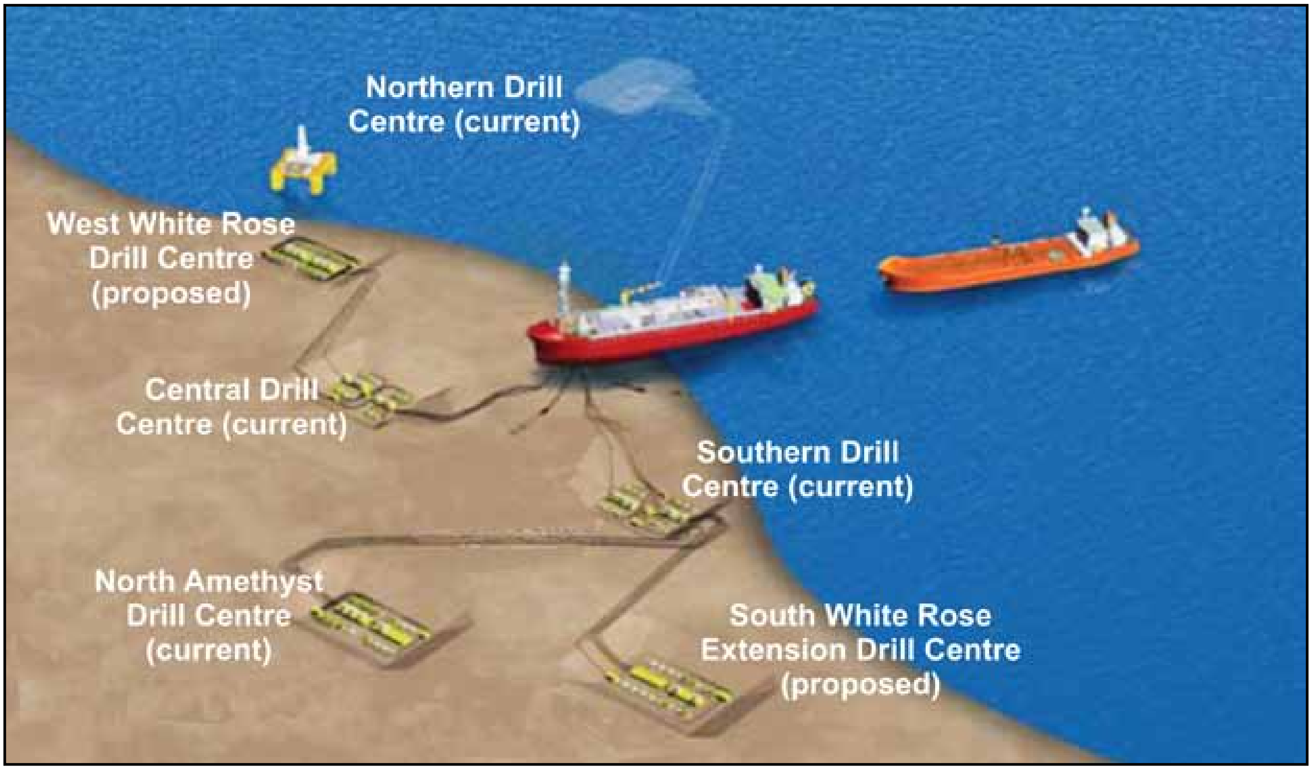
Figure #9 - Jeanne d'Arc Basin



In 2012, production at the North Amethyst field was also affected by the extended maintenance program conducted to the SeaRose FPSO, as described in Section 2.3. As of December 31, 2012, North Amethyst was operating with seven development wells, consisting of four oil producers and three water injectors. Total oil production in 2012 was 6.9 million barrels of oil for an average production of 18,920 bopd. Cumulative production to December 31, 2012 was 23.1 million barrels representing 34.0% of the current total recoverable reserve estimate.

Production from North Amethyst in 2010 was an important milestone as it represented pro-

Figure #10 - North Amethyst Tie Back Development via SeaRose FPSO



duction 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.

2.5 Hebron/Ben Nevis Field

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

The Hebron field was discovered in 1981 when the Mobil et al Hebron I-13 discovery well recovered hydrocarbons from five intervals with a combined flow rate of 9,070 barrels of oil per day. The field is located in the Jeanne d'Arc Basin approximately 31 kilometers southeast of Hibernia, 8 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 8 on page 19 that details field locations.

The C-NLOPB have assigned a reserve estimate for the Hebron field at 707 million barrels of recoverable oil. Estimates for the Ben Nevis and West Ben Nevis discoveries by the C-NLOPB 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 shortly thereafter the C-NLOPB referred the development plan to a public review. The public review commissioner submitted a report on February 28, 2012 recommending approval of the plan subject to a number of terms and conditions. Upon review of the commissioner's report and following their own internal analysis, the C-NLOPB approved the development plan, also 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 sanctioned the Hebron project on December 31, 2012.

The Hebron/Ben Nevis area consists of five oil reservoirs (pools) as outlined in Figure 11, on page 25. The main Hebron field includes pool 1 followed to the south 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.

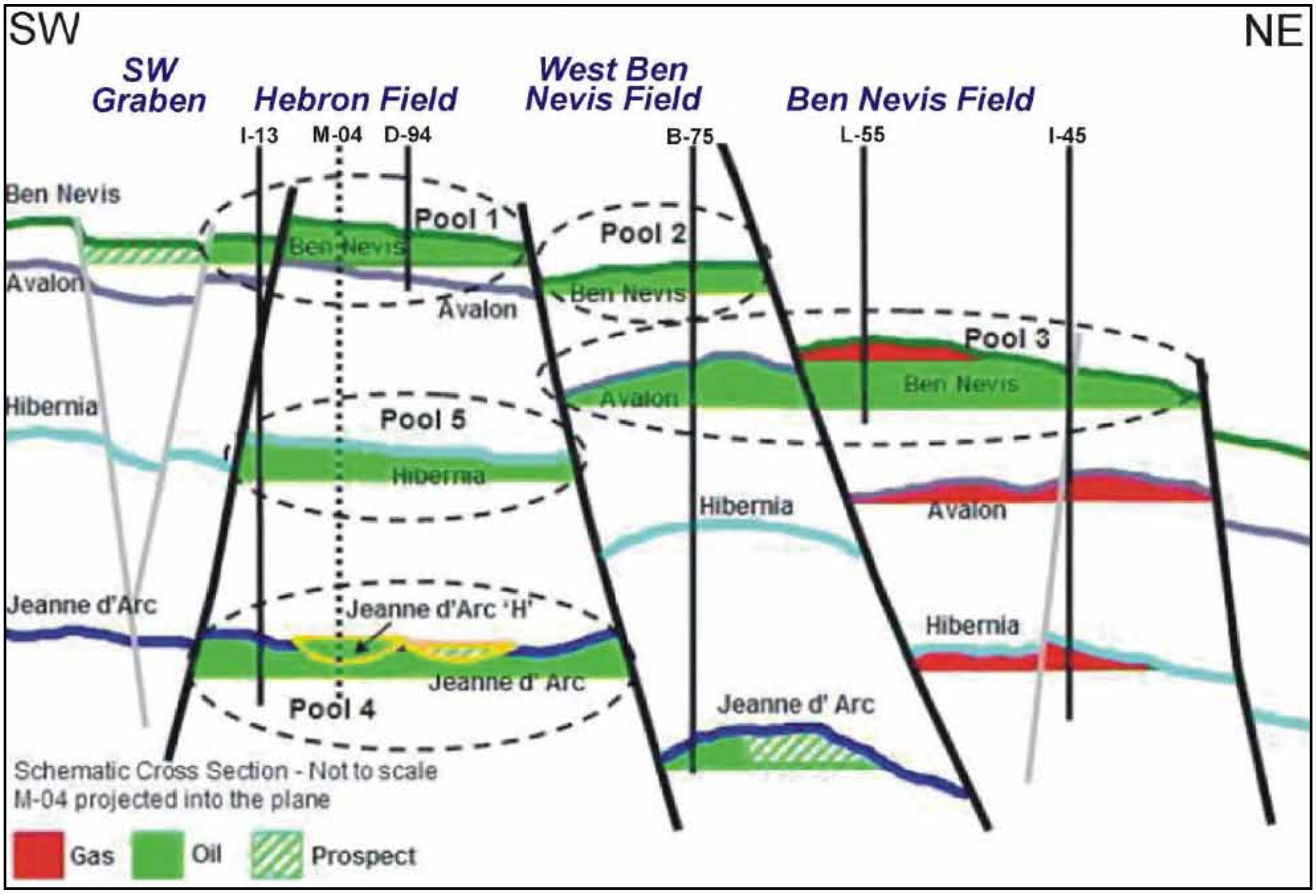


Figure #11 - Hebron/Ben Nevis resevoirs

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, the estimated capital costs for the Hebron project has increased and is now projected at $14 billion CAD. Construction of the GBS will be completed at the Nalcor owned Bull Arm, NL fabrication site and significant work was completed at the site in 2012 preparing for construction to commence. This work included upgrading the main fabrication hall, construction of two new concrete batch plants, construction of a new worker's camp, construction of the water tight bund wall, dewatering of the drydock, etc. 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. 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

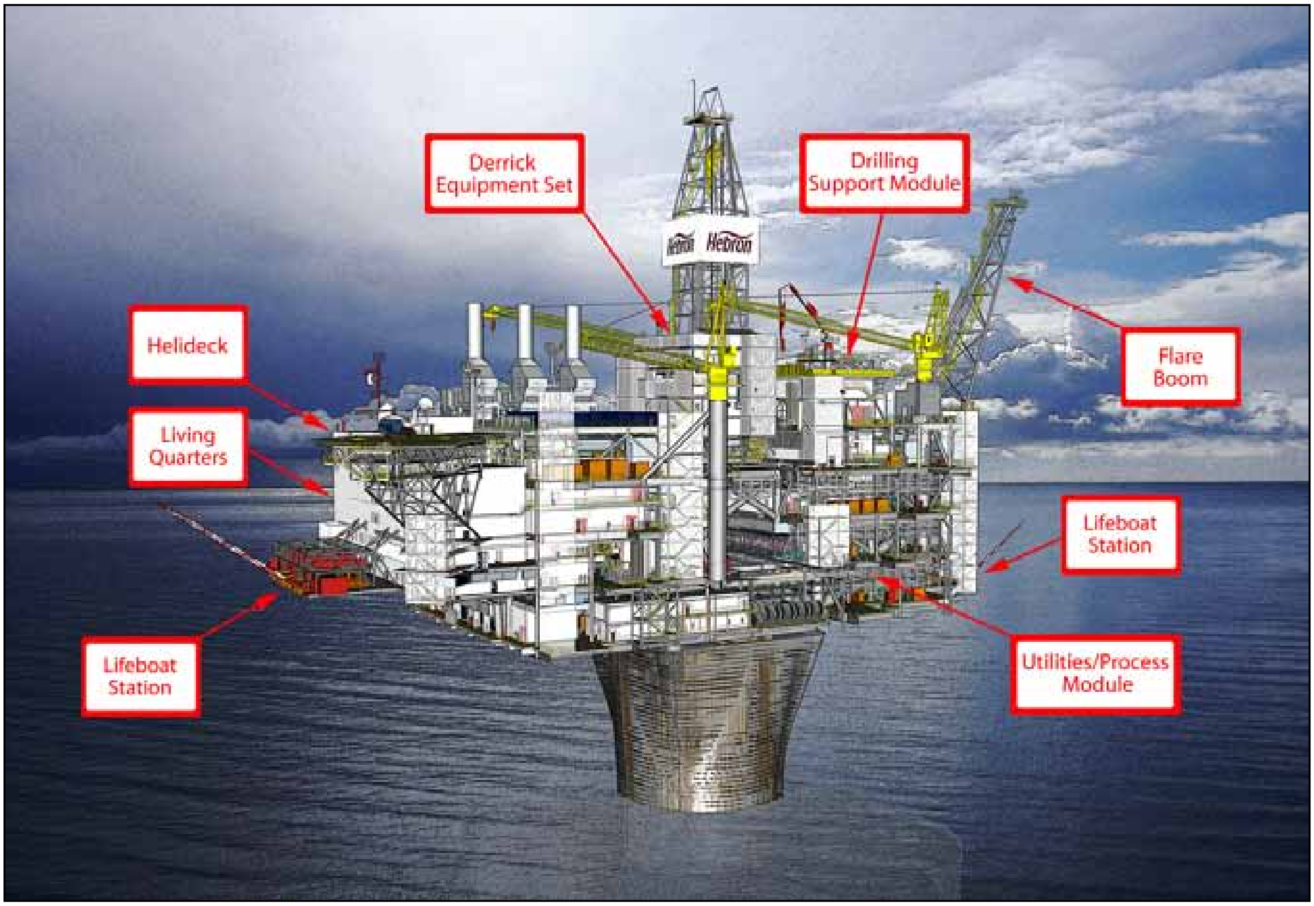
(DSM), the drilling equipment set (DES), the living quarters, the helideck, the flare boom and the lifeboat stations. Under the terms of the development agreement with the Government of Newfoundland and Labrador, it was stipulated that the helideck, the life boat station and the flare boom would be built in province. It was also agreed that the living quarters, the DSM and the DES would be built in the province if there is sufficient labour and capacity at local fabrication yards. Due to the size of the utilities and process module, it was agreed that an International Expression of Interest (EOI) would be issued for its construction. In 2012, it was announced that Worley Parsons was awarded the next phase in the construction of the topsides which includes the engineering, procurement and construction. Worley Parsons previously held the contract for the FEED and detailed design work. It was also announced that US engineering company, Fluor Corporation would assist Worley Parsons with overall project management.

Several major contracts were awarded in 2012 regarding the 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) were 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. While the awarding of the DSM has not been completed, ExxonMobil have announced that they are negotiating with Kiewit Infrastructure Canada for the construction of this module at Kiewit's Cow Head fabrication facility in Marystown, NL. An announcement on the progress of negotiations is expected early in 2013.

With the signing of the Hebron Development Agreement with the Province of Newfoundland and Labrador back in 2008, it was expected that three of the four major modules would be built in the province. The overlying assumption in the agreement was that all work that could be completed in the province would be completed in the province, as long as it did not affect the overall project completion and cost schedule. The modules that were expected to be built in the province at the time included the accommodations module (now awarded to the NEAL Partnership), the DSM (under negotiation with Kiewit Infrastructure), and the DES. Midway through 2012, a disagreement developed between ExxonMobil and the Provincial Government over whether the capacity existed in the province to complete all three modules without unduly affecting the overall project completion and cost schedule.

In October 2012, it was announced that an agreement had been reached between Exxon-Mobil and the Provincial Government to resolve a dispute concerning in-province fabrication of a Drilling Equipment Set for the Hebron Project. The Drilling Support Module and the Ac-

Figure #12 - Proposed Hebron Development



commodations Module make up the remaining modules to be fabricated at Marystown and Bull Arm respectively.

It was agreed that the Province will collect $150 million on June 30, 2016, which represents the most probable future date at which any replacement work would reasonably commence. Strategic investments will be made in the province's education and health care systems for the benefit of Newfoundlanders and Labradorians.

Contracts to construct the remaining components, the helideck, the flare boom and the life boat stations, are also expected to be awarded in 2013. Construction of the modules and components is expected to ramp up in 2013 with integration of all completed modules scheduled 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 13 below. In 2012, land associated with the Garden Hill South oil pool covered under the production lease issued by the Province of Newfoundland and Labrador was renewed for a further five year term under Lease 2002-1(A). Also in 2012, the operator of the production lease changed its name from PDI Production Inc. to Enegi Oil Inc. Enegi Oil Inc. is 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 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. Following several workover programs on the PAP 1 Sidetrack 3 well in 2010 and 2011, further testing was conducted in 2012. This included extended production periods where overall well pressure was monitored. The results of these tests will be used to determine long term sustainable flow rates. The company has announced that further production testing is planned for 2013 including the possibility of the installation of artificial gas lift equipment to assist with flow rates.

Figure #13 - Location of Port au Port Peninsula

During the extended production test in 2012, a total of approximately 4,350 barrels of oil was recovered raising the total cumulative production at the Garden Hill South site to slightly in excess of 39,700 barrels of oil.

3.0 Regional Activity Update

3.1 East Coast Offshore - North Grand Banks

Resource Opportunity - 2012 Call for Bids

There was one Call for Bids completed in 2012 for a single parcel of land in the Flemish Pass/North Central Ridge area as detailed in the graphic on page 30. With a total bid of $19,875,875 CAD, the successful group was led by Husky Oil Operations Limited with co-venture partners Suncor Energy Inc. and Repsol E&P Canada Ltd. The criteria used for evaluation of the bids was the highest total work expenditure commitment submitted. An exploration license will be issued for this land parcel early in 2013 when the relevant terms and conditions are met.

Call for Bids NL12-02-01 (Flemish Pass/North Central Ridge)	
Parcel 1 (208,899 ha)	Bid amount - $19,875,875
Husky Oil Operations Ltd.	40%
Suncor Energy Inc.	35%
Repsol E&P Canada Ltd.	25%

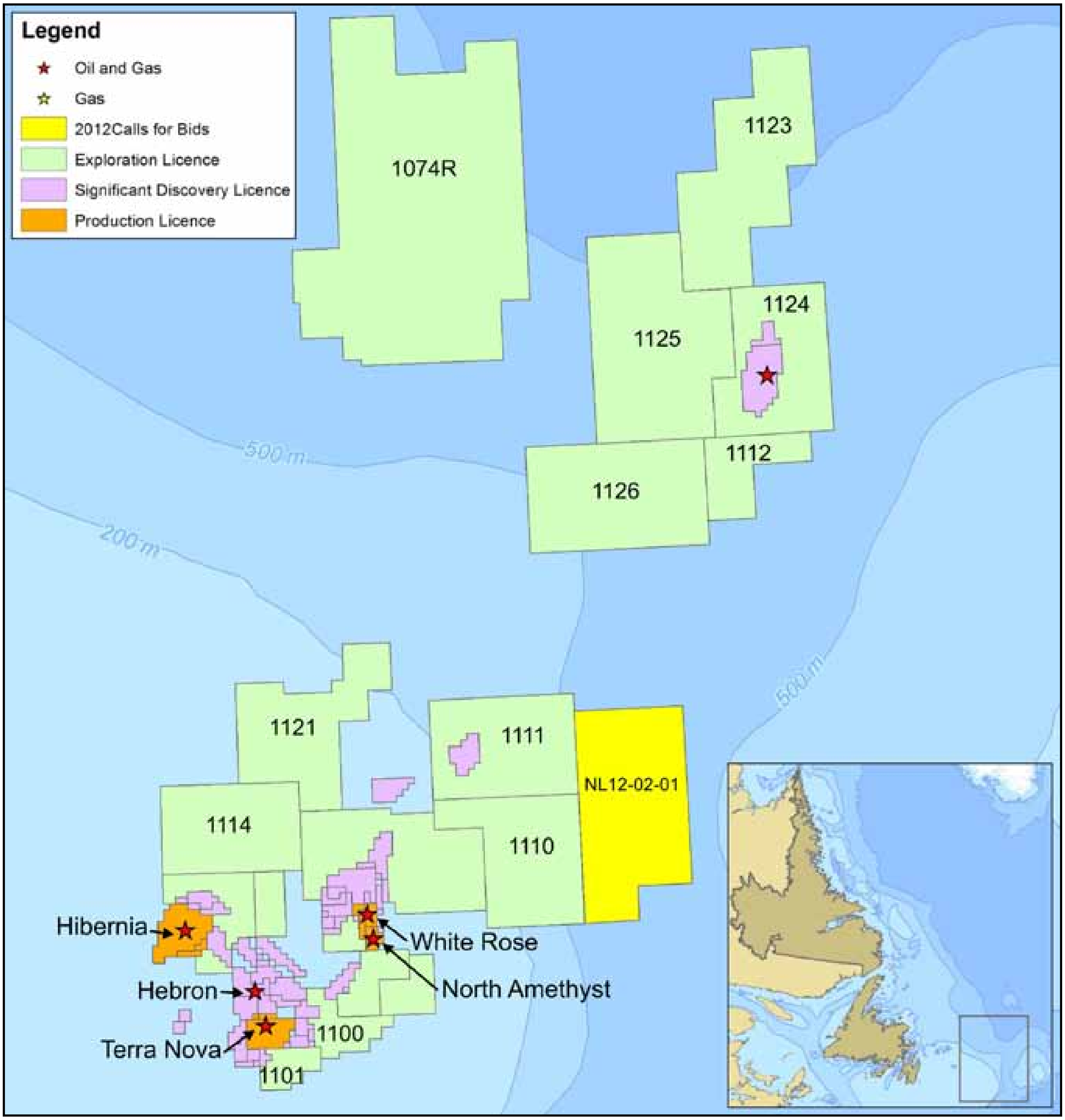
Exploration Activity - Drilling Programs

Off the east coast, Husky Energy spud the Searcher C-87 exploration well in the Jeanne d'Arc Basin on August 8, 2012 utilizing the drilling rig, Henry Goodrich. Due to mechanical issues with the rig, drilling operations were suspended late in August, 2012 and the rig was moved off location for repairs. On November 26, 2012, the drilling rig GSF Grand Banks returned to the site to complete the well and as of December 31, 2012 drilling operations were ongoing

Geoscience Programs

Two major seismic programs were completed in the region in 2012. Statoil Canada, utilizing the MV Geo Caribbean, collected 230,945 line kilometers (5,774 km^2) of 3D data in the Flemish Pass/North Central Ridge where they are conducting a major exploration program. Meanwhile, Multi Klient Invest ASA continued with their multi year seismic program off the coast of Newfoundland and Labrador utilizing the M/V Sanco Spirit to collect 7,957 line

Figure #14 - East Coast Regional Map



kilometers of 2D data on the North East - Newfoundland Slope. It is expected that the Sanco Spirit will return again in 2013 to further enlarge the 2D seismic coverage area off the coast of Newfoundland and Labrador.

Seven wellsite surveys were completed off the east coast in 2012 with all being located in the Jeanne d'Arc Basin. Five were completed by Husky Energy, one by Statoil Canada and one by Suncor Energy. These wellsite surveys are completed in anticipation of future drilling programs.

Licensing – Land Rights

There were four new licenses issued in several categories in 2012. Three sections of Exploration License (EL) 1093 located in the Hibernia Southern Extension were converted to Production License 1011. The remaining land sections previously covered by EL 1093 remain as part of the existing exploration license. As a result of the 2011 Call for Bids, two new exploration licenses, EL 1125 and EL 1126, were issued to Statoil Canada as representative in the Flemish Pass Basin. And lastly, nine sections of EL 1095 located in the Jeanne d'Arc Basin were converted into Significant Discovery License (SDL 1050). This conversion was a result of new reservoir modelling of the western portion of the Terra Nova field. As EL 1095 was at the end of its term, the remaining land sections were relinquished back to the crown.

Drilling deposits were posted for three existing exploration licenses (EL 1074R, EL 1090R, and EL1099) that were at the end their respective terms. As a result, their relevant expiry dates were extended for an additional year. One exploration license, EL 1096, with Husky Oil as representative, was at the end of its term in 2012 and the land was subsequently relinquished back to the crown.

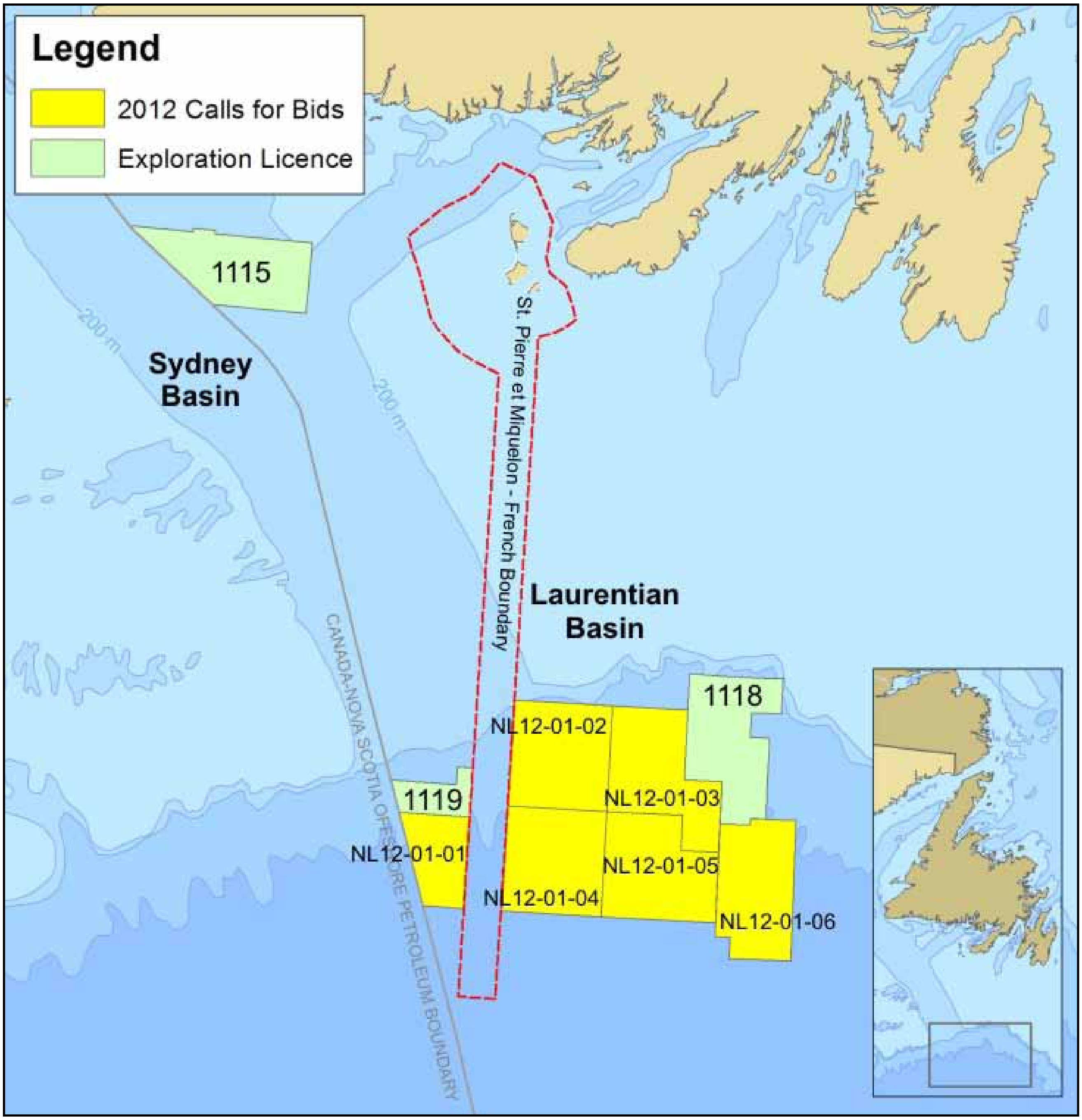
3.2 South Coast Offshore

Resource Opportunity – 2012 Call for Bids

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. The chart below outlines the bid amounts for each of the parcels. Exploration licenses for these parcels as shown in Figure 15, page 33 will be issued early in 2013 when all relevant terms and conditions are met.

Call for Bids NL12-01 (Laurentian Basin)	
Parcel 1 (143,588 ha)	Bid amount - $31,387,926
Shell Canada	100%
Parcel 2 (286,598 ha)	Bid amount - $5,173,777
Shell Canada	100%
Parcel 3 (294,260 ha)	Bid amount - $1,795,455
Shell Canada	100%
Parcel 4 (289,016 ha)	Bid amount - $57,393,786
Shell Canada	100%
Parcel 5 (296,530 ha)	Bid amount - $1,249,056
Shell Canada	100%

Figure #15 - South Coast Regional Map



3.3 West Coast Onshore and Offshore

Land Rights Licensing

Exploration Licenses 1127 and 1128, located in the Anticosti Basin, were issued to Ptarmigan Energy in 2012 as a result of the company being the successful bidder on the land pacels during the 2011 Call for Bids. Exploration license 1102 held by B.G. Oil and Gas Inc. was at the end of its term in 2012 and was relinquished back to the crown.

NWest Energy Corp. announced on January 17, 2012 that it had sold its remaining interest in offshore exploration license EL1097R to Shoal Point Energy Ltd. Terms of the deal included Shoal Point Energy posting a $1.0 million drilling deposit with C-NLOPB to extend Term 1 of the exploration license until January 15, 2013. NWest also received two million common shares and an equivalent amount of common share warrants of Shoal Point Energy Ltd. Further the purchase agreement included terms for the distribution of additional common shares and warrants of Shoal Point Energy to NWest Energy as well as gross overriding royalty payments, based on milestones for drilling and production targets.

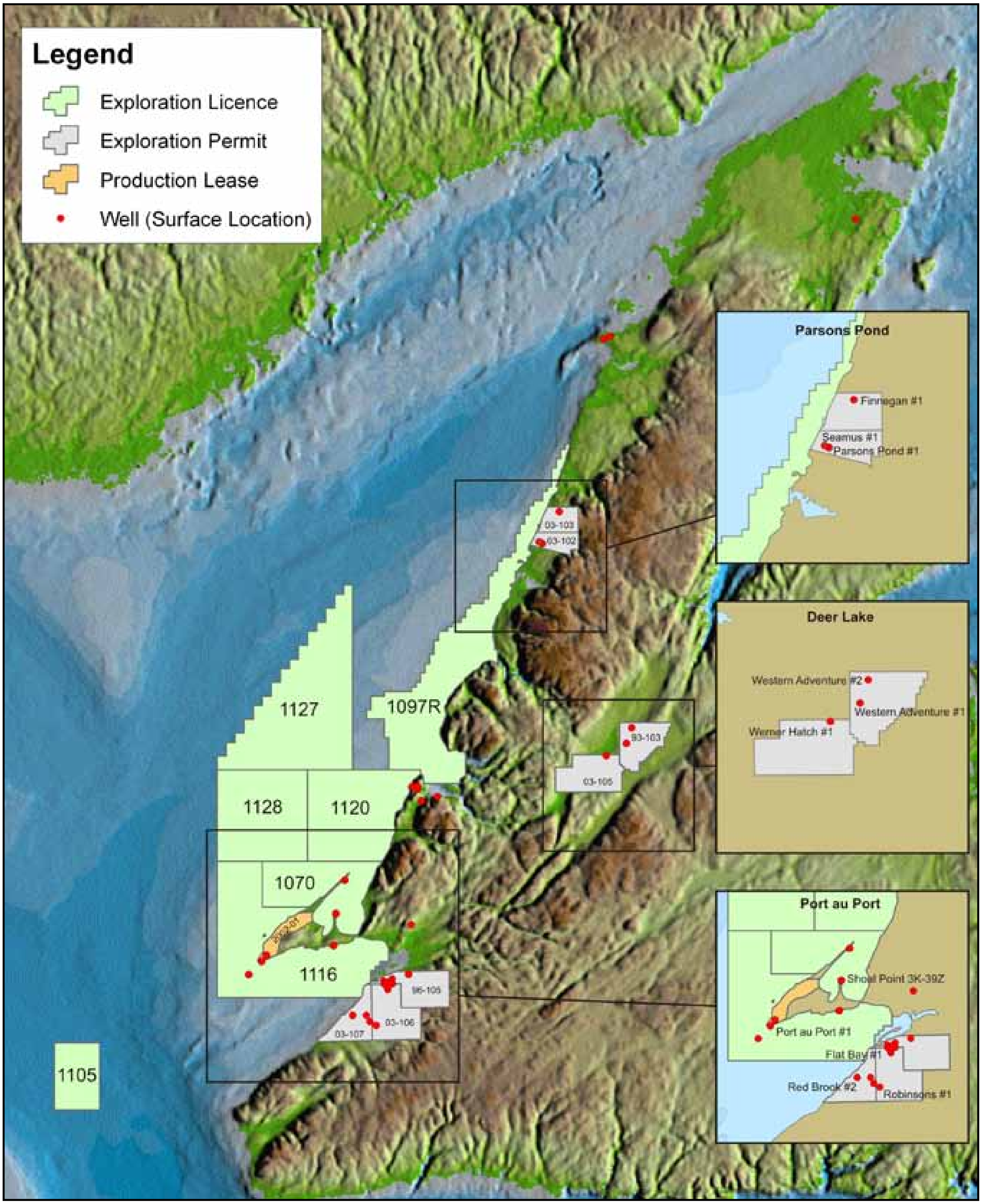
Also, on May 10, 2012 Vulcan Minerals Inc. announced that it had sold its 50% working interest in three onshore exploration permits EP (03-106, 03-107 and 96-105) in the Bay St. George area to Investcan Energy Corporation for $2.5 million in cash and a 2.5% gross overriding royalty on all future production. Investcan Energy now owns 100% interest in the three permits and have assumed the operator position from Vulcan. Investcan have been given approval for an appraisal pilot drilling program of the permits in the Flat Bay area as detailed below.

Exploration Activity

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 or further exploration plans have been announced by the company.

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 License 1070. Shoal Point announced that the well penetrated a shale interval with hyrocarbon potential. They plan to return in 2013 to drill a further appraisal well and perform the necessary tests for application for a Significant Discovery License from the C-NLOPB.

Figure #16 - West Coast Regional Map



3.4 Labrador Offshore

Geoscience Programs

Multi Klient Invest ASA, a consortium led by TGS NOPEC Geophysical Company and Petroleum Geo-Sercices Inc., continued with their major 2D survey offshore Labrador in 2012. The program commenced in 2011, and in 2012 a total of approximately 22,000 line kilometers of data was collected. The MV Sanco Spirit completed the planned program late in 2012 and the vessel commenced a further 2D seismic program offshore northeastern Newfoundland as detailed in section 3.1.

Licensing - Land Rights

On April 16, 2012, Vulcan Minerals Inc. announced that Investcan Energy Corporation, owners of 70% interest in their Exploration License 1107, acquired the remaining 30%. Investcan Energy paid $1.75 million on closing with a commitment for a further $1.0 million in cash payments based on milestones regarding exploration drilling and license disposition.

Figure #17 - Labrador Land Rights

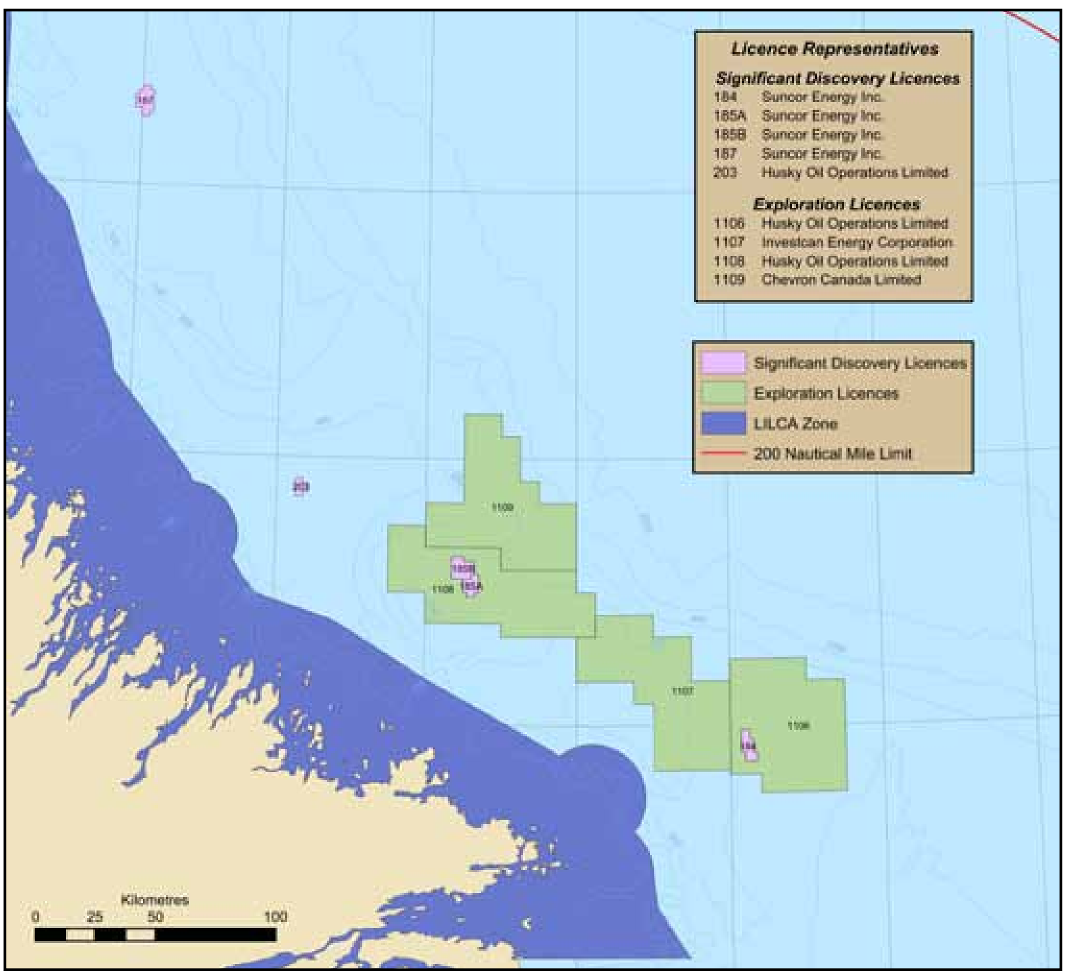
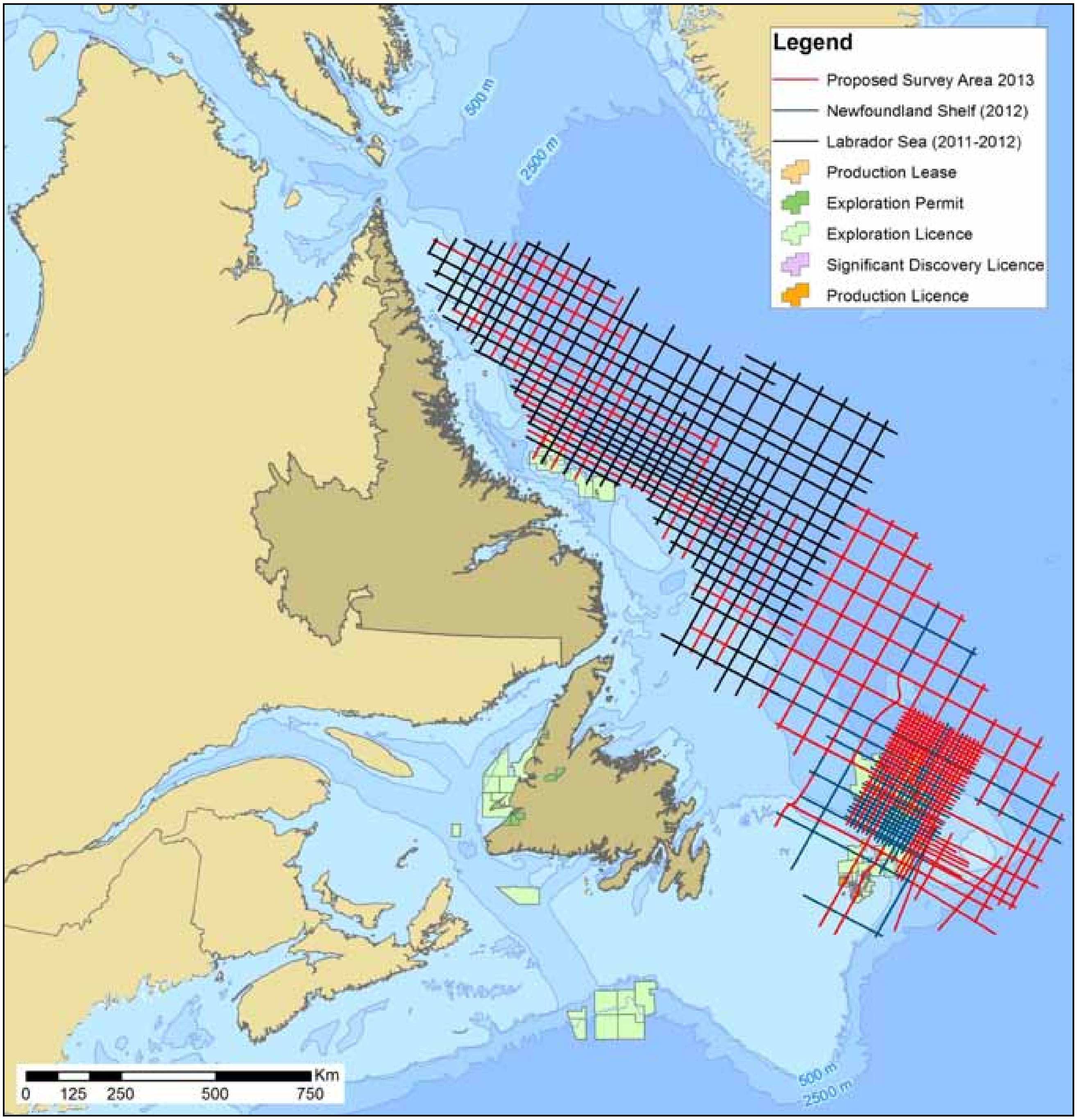
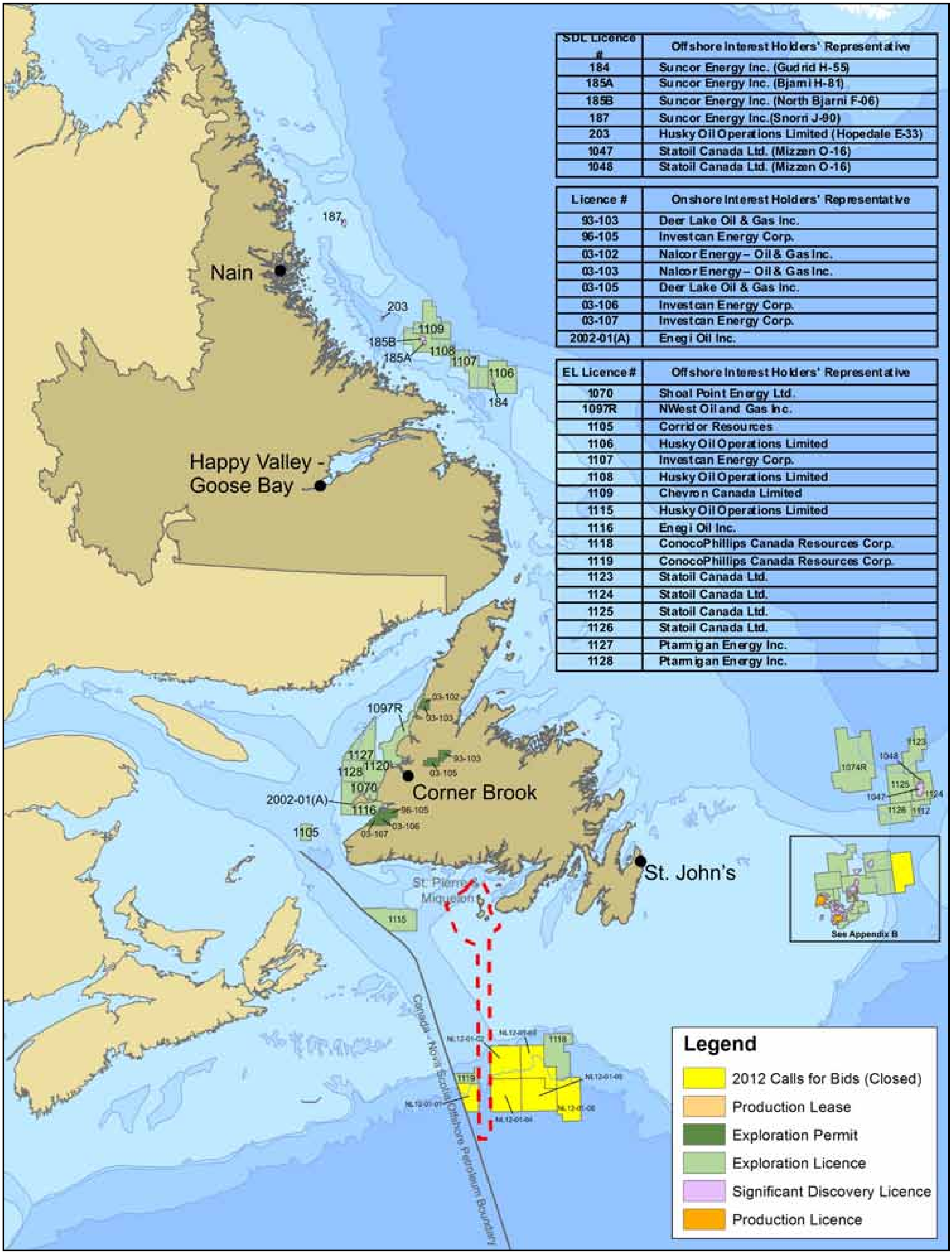


Figure #18 - TGS - PGS Eastern Canada 2D Seismic Survey



Appendix A - Newfoundland and Labrador Land Rights Map

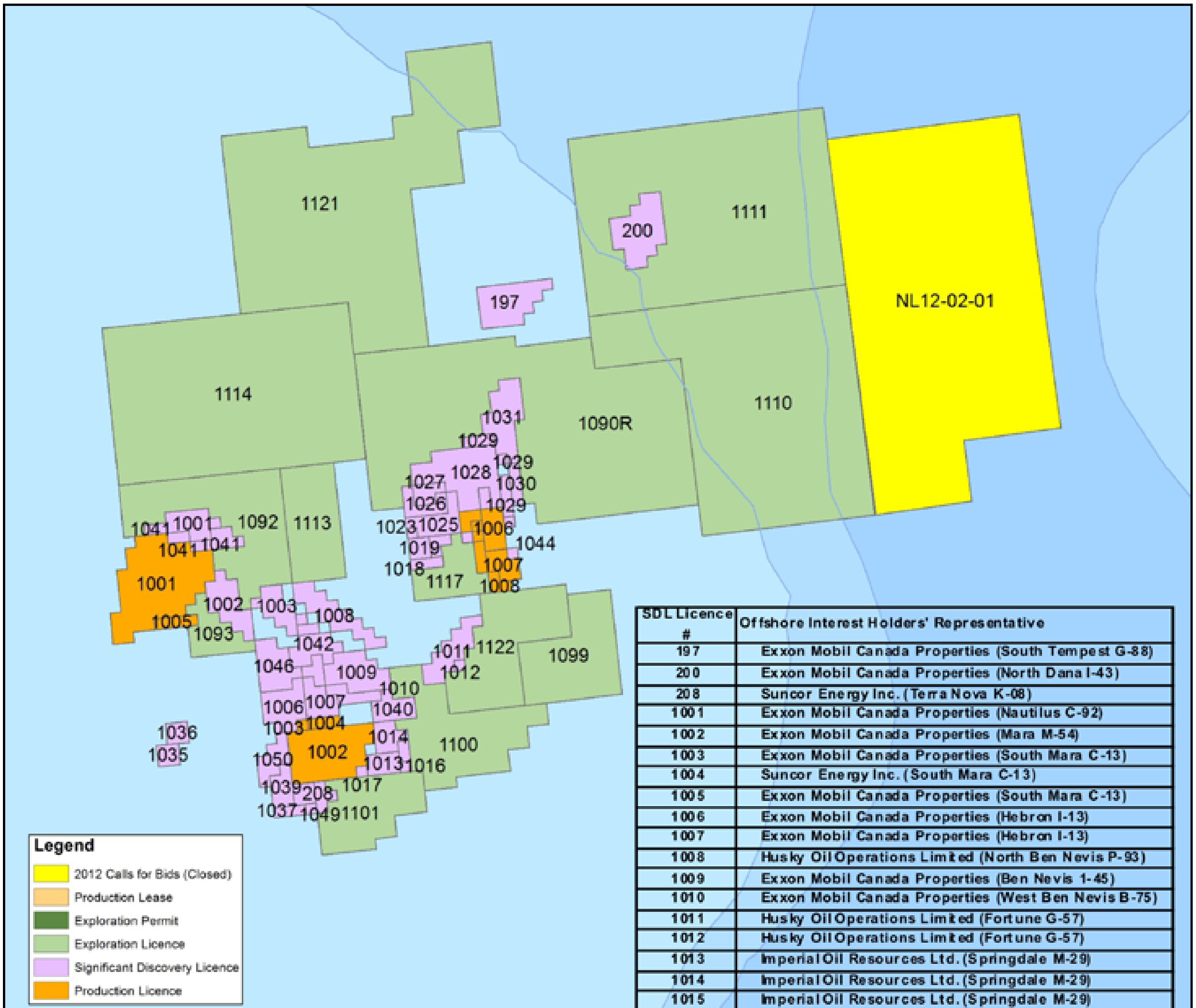


SDL Licence #	Offshore Interest Holders' Representative
184	Suncor Energy Inc. (Gudrid H-55)
185A	Suncor Energy Inc. (Bjarni H-81)
185B	Suncor Energy Inc. (North Bjarni F-06)
187	Suncor Energy Inc.(Snorri J-90)
203	Husky Oil Operations Limited (Hopedale E-33)
1047	Statoil Canada Ltd. (Mizzen O-16)
1048	Statoil Canada Ltd. (Mizzen O-16)

Licence #	Onshore Interest Holders' Representative
93-103	Deer Lake Oil & Gas Inc.
96-105	Investcan Energy Corp.
03-102	Nalcor Energy – Oil & Gas Inc.
03-103	Nalcor Energy – Oil & Gas Inc.
03-105	Deer Lake Oil & Gas Inc.
03-106	Investcan Energy Corp.
03-107	Investcan Energy Corp.
2002-01(A)	Enegi Oil Inc.

EL Licence #	Offshore Interest Holders' Representative
1070	Shoal Point Energy Ltd.
1097R	NWest Oil and Gas Inc.
1105	Corridor Resources
1106	Husky Oil Operations Limited
1107	Investcan Energy Corp.
1108	Husky Oil Operations Limited
1109	Chevron Canada Limited
1115	Husky Oil Operations Limited
1116	Enegi Oil Inc.
1118	ConocoPhillips Canada Resources Corp.
1119	ConocoPhillips Canada Resources Corp.
1123	Statoil Canada Ltd.
1124	Statoil Canada Ltd.
1125	Statoil Canada Ltd.
1126	Statoil Canada Ltd.
1127	Ptarmigan Energy Inc.
1128	Ptarmigan Energy Inc.

Appendix B - Jeanne d'Arc Basin Land Rights Map



EL Licence #	Interest Holders' Representative
1090R	Husky Oil Operations Limited
1092	Suncor Energy Inc.
1093	ExxonMobil Canada Properties
1099	Husky Oil Operations Limited
1100	Statoil Canada Ltd.
1101	Statoil Canada Ltd.
1110	Husky Oil Operations Limited
1111	Husky Oil Operations Limited
1113	Suncor Energy Inc.
1114	Husky Oil Operations Limited
1117	Husky Oil Operations Limited
1121	Husky Oil Operations Limited
1122	Husky Oil Operations Limited

PL Licence #	Interest Holders' Representative
1001	ExxonMobil Canada Properties (Hibernia)
1002	Suncor Energy Inc. (Terra Nova)
1003	Suncor Energy Inc. (Terra Nova)
1004	Suncor Energy Inc. (Terra Nova)
1005	ExxonMobil Canada Properties (Hibernia)
1006	Husky Oil Operations Limited (White Rose)
1007	Husky Oil Operations Limited (White Rose)
1008	Husky Oil Operations Limited (North Amethyst)
1009	Husky Oil Operations Limited (White Rose)
1010	Husky Oil Operations Limited (White Rose)
1011	ExxonMobil Canada Properties (Hibernia)

SDL Licence #	Offshore Interest Holders' Representative
197	Exxon Mobil Canada Properties (South Tempest G-88)
200	Exxon Mobil Canada Properties (North Dana I-43)
208	Suncor Energy Inc. (Terra Nova K-08)
1001	Exxon Mobil Canada Properties (Nautilus C-92)
1002	Exxon Mobil Canada Properties (Mara M-54)
1003	Exxon Mobil Canada Properties (South Mara C-13)
1004	Suncor Energy Inc. (South Mara C-13)
1005	Exxon Mobil Canada Properties (South Mara C-13)
1006	Exxon Mobil Canada Properties (Hebron I-13)
1007	Exxon Mobil Canada Properties (Hebron I-13)
1008	Husky Oil Operations Limited (North Ben Nevis P-93)
1009	Exxon Mobil Canada Properties (Ben Nevis 1-45)
1010	Exxon Mobil Canada Properties (West Ben Nevis B-75)
1011	Husky Oil Operations Limited (Fortune G-57)
1012	Husky Oil Operations Limited (Fortune G-57)
1013	Imperial Oil Resources Ltd. (Springdale M-29)
1014	Imperial Oil Resources Ltd. (Springdale M-29)
1015	Imperial Oil Resources Ltd. (Springdale M-29)
1016	Imperial Oil Resources Ltd. (Springdale M-29)
1017	Husky Oil Operations Limited (Springdale M-29)
1018	Husky Oil Operations Limited (Whiterose N-22)
1019	Husky Oil Operations Limited (Whiterose N-22)
1020	Husky Oil Operations Limited (Whiterose N-22)
1023	Husky Oil Operations Limited (Whiterose N-22)
1024	Husky Oil Operations Limited (Whiterose N-22)
1025	Husky Oil Operations Limited (Whiterose N-22)
1026	Husky Oil Operations Limited (Whiterose N-22)
1027	Husky Oil Operations Limited (Whiterose N-22)
1028	Husky Oil Operations Limited (Whiterose N-22)
1029	Husky Oil Operations Limited (Whiterose N-22)
1030	Husky Oil Operations Limited (Whiterose N-22)
1031	Husky Oil Operations Limited (Trave E-87)
1035	Suncor Energy Inc. (East Rankin H-21)
1036	Suncor Energy Inc. (East Rankin H-21)
1037	Suncor Energy Inc. (King's Cove A-26)
1038	Suncor Energy Inc. (King's Cove A-26)
1039	Suncor Energy Inc. (King's Cove A-26)
1040	Statoil Canada Ltd. (West Bonne Bay C-23)
1041	Chevron Canada Ltd. (Nautilus)
1042	Husky Oil Operations Limited (Ben Nevis I-45)
1044	Husky Oil Operations Limited (Whiterose)
1045	Husky Oil Operations Limited (Whiterose)
1046	Husky Oil Operations Limited (Hebron I-13)
1047	Statoil Canada Ltd. (Mizzen O-16)
1048	Statoil Canada Ltd. (Mizzen O-16)
1049	Statoil Canada Ltd.(King's Cove A-26)
1050	Suncor Energy Inc. (Terra Nova K-08)

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Department of Natural Resources
P. O. Box 8700
St. John's, NL
Canada, A1B 4J6

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