Newfoundland Labrador

Government of Newfoundland and Labrador
Department of Natural Resources

Oil and Gas Report
August 2007

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Table of Contents

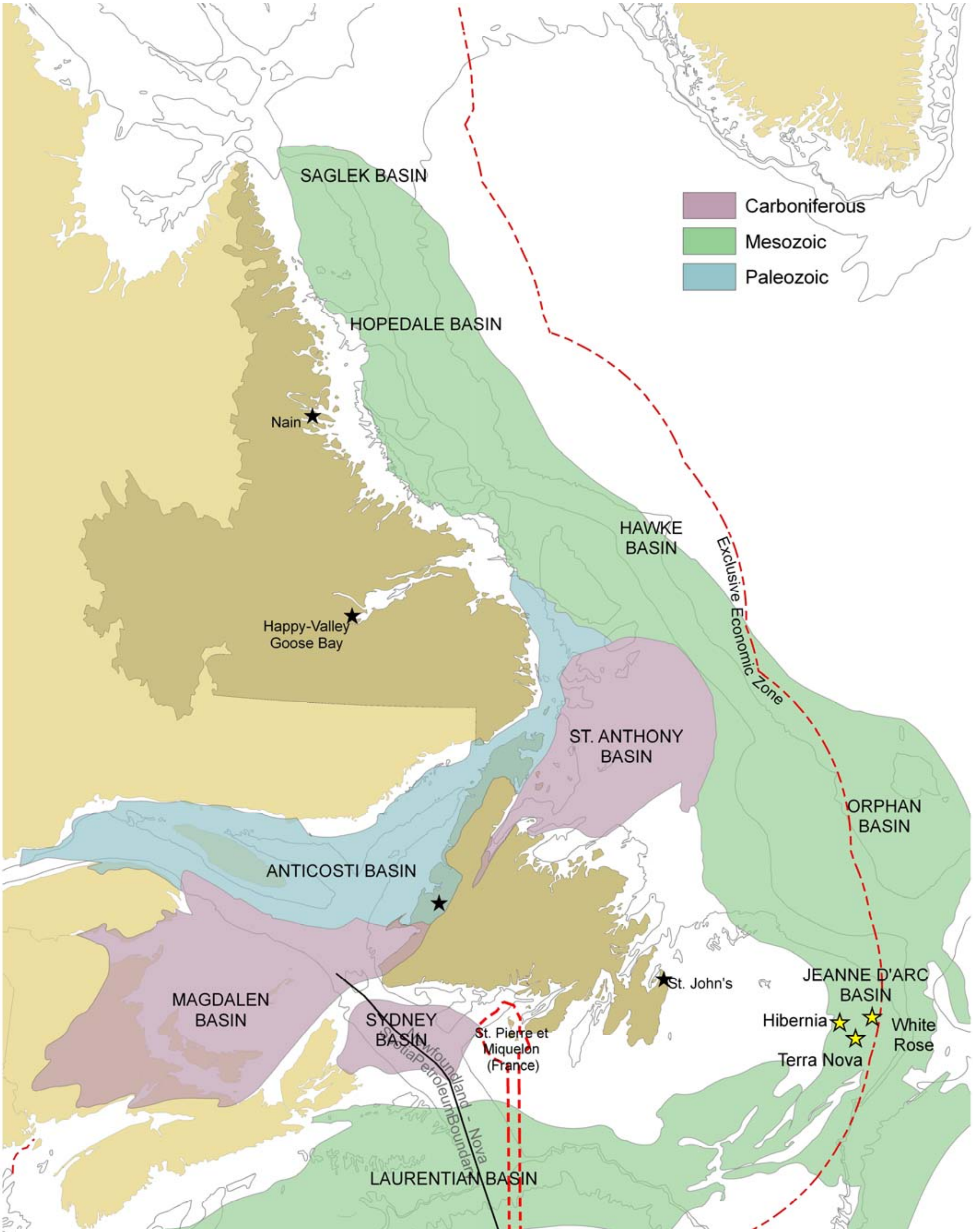


Figure 1 - Sedimentary Basins of Atlantic Canada

Offshore Newfoundland

Land Management

About 4 million hectares are currently held under licence in the offshore area of which about 1 million are located offshore western Newfoundland and 3 million on the east coast (Figures 2a & 2b). Additionally, exploration licences were issued in July 2004 for approximately 2.5 million hectares in the Laurentian Basin south of St. Pierre and Miquelon.

There is currently $819 million in work expenditure commitments on the books. An additional $19.5 million was negotiated with the Laurentian Basin licences. These licences result from negotiated agreements with former federal permit holders to convert the federal permits in the Newfoundland and Labrador portion of the Laurentian Basin into new ELs.

On March 2nd, 2005, Shell Canada Limited announced it had concluded a farm-in agreement with ExxonMobil Canada and Imperial Oil Resources, acquiring a 20% interest in the Orphan Basin parcels. Under the terms of the agreement, ExxonMobil and Imperial Oil reduced its share by 10%, providing Shell with its 20% interest. In April, 2005, Norsk Hydro boosted its interest in the discovery licence SDL 1040 also known as the Torbay prospect, to 90% by acquiring BP's interests. In June of 2004, BHP Billiton farmed in with ConocoPhillips and Murphy Oil Ltd. as part of the Laurentian exploration group.

About 4 million hectares are currently held under licence in the offshore area

The C-NLOPB offered three separate Calls for Bids in 2006. All Calls closed in November 2006 and resulted in successful bids for six parcels comprising a total of 604, 647 hectares. Three of these are located in the Jeanne d'Arc Basin and the remaining three are located in the Western Newfoundland and Labrador offshore region. A total of $32.35 million in work commitments were received. Successful bidders included Husky, Norsk Hydro, NWest Energy and B.G. Capital. Six exploration licences were issued to the successful Bidders on January 15, 2007. The Jeanne d'Arc Basin parcels (76, 419 hectares) went for a combined total of $31, 400, 000. At $410.89 per hectare, this represents the second highest dollars per hectare total since 1995 ($2999.31/hectare).

The C-NLOPB offered two separate Calls for Bids in May 2007. Call NL07-1 is for one parcel located offshore Western Newfoundland. This call closes on November 30, 2007. NL07-2 is for four parcels located offshore Labrador. This Call closes on August 1, 2008. Parcels for both Calls comprise a total of 991,458 ha. The Board is conducting Strategic Environmental Assessments for the parcel areas in both NL07-1 and NL07-2.

* Unless otherwise stated, all quotes are in Canadian dollars. Exchange Rate: $1.00 Can ~ $.95US.

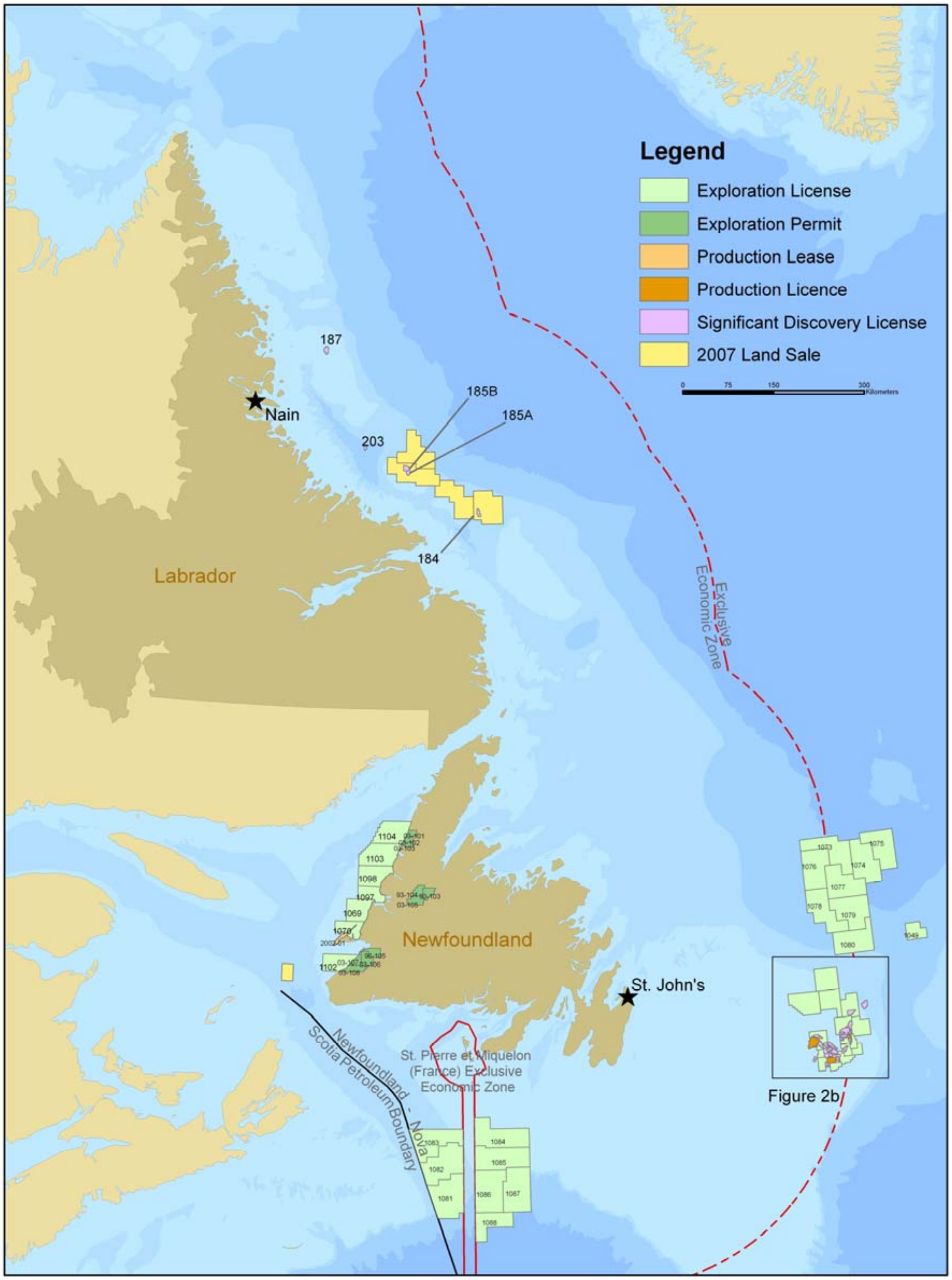


Figure 2a - Newfoundland and Labrador Petroleum Rights

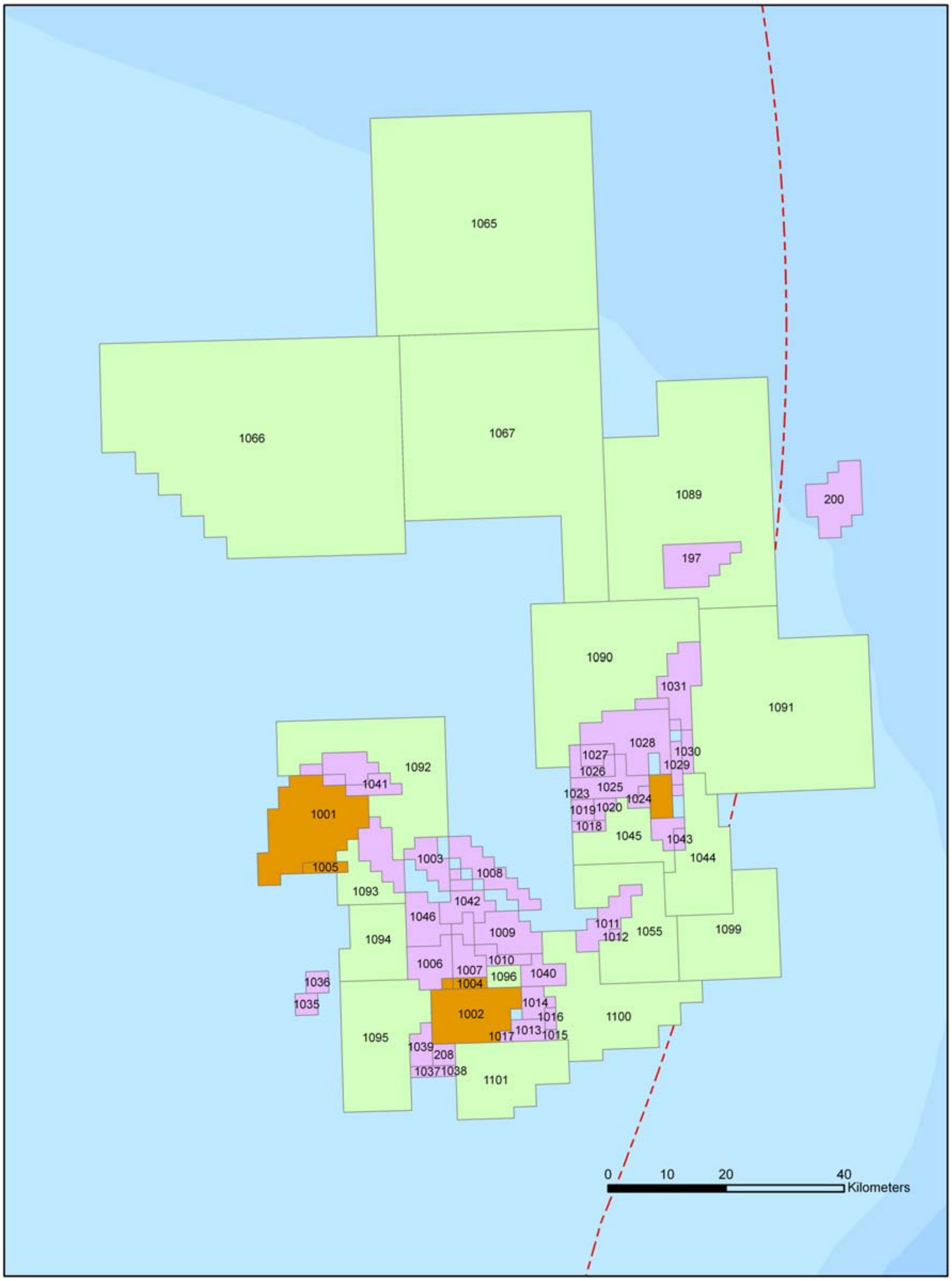


Figure 2b - Northern Grand Banks Petroleum Rights

Exploration and Delineation Activity

Since the first well in 1966 to June 30, 2007, 318 wells have been spudded (including exploration, delineation and development wells, major re-completions and sidetracks at Hibernia, Terra Nova and White Rose) and in excess of 1.9 million km of seismic data have been collected in the Province's offshore area. Industry expenditures to the end of 2006, have totalled approximately $21 billion (including the Hibernia, Terra Nova and White Rose developments). Exploration expenditures alone account for about $4.8 billion by which some 2.7 billion barrels of oil and 10.2 trillion cubic feet of natural gas and 478 million barrels of natural gas liquids have been discovered.

A Canadian record for deep water drilling was established with the spudding of the Great Barasway F-66 well

2006 was a transition year for seismic acquisition following up from a record breaking year in 2005. In 2007, seismic programs were completed by Husky on their East Trave, Triton and Emerald prospects in the Northern Jeanne d'Arc region totaling 522 km of 2D seismic data. Petro Canada completed their 3D seismic survey on their North Mara prospect acquiring some 20, 842 CMP km. A 910 line km electromagnetic resistivity survey is currently being conducted by operator ExxonMobil Canada in the Orphan Basin. This is in addition to a 717 line km electromagnetic resitivity survey conducted last year in the Orphan Basin by the same operator, the first of this type of program in our offshore and in Canada.

There were two offshore exploration wells spudded in 2006, while one well, Hibernia B-16 54, which was spudded in August of 2005 was plugged and abandoned in May after experiencing operational challenges. On August 18, 2006, the well, *Chevron et al. Great Barasway F-66* set a Canadian record for deep water drilling, spudding the well in water depths exceeding 2335m. The well was completed in April 2007. Chevron also announced in April that ExxonMobil would be operator of a two well program for the Orphan Basin in 2008 or 2009.

Husky Energy commenced its 2006 Jeanne d'Arc Basin drilling program using the jack-up rig, Rowan Gorilla VI, by spudding the well *Husky Oil et al White Rose O-28Y*, on SDL 1044 followed immediately by a companion sidetrack *O-28X*. Husky later announced a hydrocarbon discovery associated with this well program in the range of 50 to 200 million barrels of recoverable resources with a most likely case of 120 million barrels. The jack-up then mobilized to SDL 1040, where Husky concluded a farm-in deal with Norsk Hydro and was operator of the *Husky Oil et al West Bonne Bay F-12* and sidetrack *F-12Z*. In a joint statement released on December 6, 2006, partners Husky and Norsk Hydro announced that hydrocarbons had been encountered in the Upper Hibernia Formation and that analysis was ongoing to determine the extent of the oil and gas accumulation. Husky then drilled the exploration well, *Husky Oil et al North Amethyst K-15* to test a feature on the North Amethyst Ridge. On November 16, 2006 Husky announced that the well had discovered hydrocarbons estimated at between 40 to 100 million barrels of recoverable oil resources with a likely estimate of 70 million barrels.

On November 21, 2006, Petro Canada commenced the drilling of the *Petro Canada et al. Terra Nova I-66* in the southern part of the Far East block using the semi-submersible rig Henry Goodrich. This well was suspended on February 16, 2007. Petro Canada re-entered the Terra Nova L-98 6 well on February 17, 2007 to abandon the perforated zones and drilled the L-98 6Z sidetrack well on March 29. This was the last well to be drilled in a six-year, 27-well drilling program in the Terra Nova oilfield. The Henry Goodrich carried out several workovers and interventions since this well was completed in May and is scheduled to motor to Conception Bay in early August where Petro Canada will remove equipment used during the Terra Nova drilling program before handing the rig over to Norsk Hydro who will take the rig to the U.S. Gulf of Mexico. That contract wraps up in 2009.

Discovered Resources

To date, 23 significant discoveries have been made in the offshore area, including 5 on the Labrador Shelf and 18 on the Grand Banks. For offshore Labrador, the total discovered recoverable resource (C-NLOPB estimate; expressed at a 50% probability of occurrence) is 4.2 trillion cubic feet of natural gas and 123 million barrels of natural gas liquids. For the northeast Grand Banks region, total discovered recoverable resource is 2.75 billion barrels of oil, 6.0 trillion cubic feet of natural gas and 355 million barrels of natural gas liquids (see Table 1).

Table 1— Discovered Resources [1] — Newfoundland Offshore Area

	Oil		Gas		NGL's	
Field Name	**Million m^3**	**MMBbls**	**Billion m^3**	**bcf**	**Million m^3**	**MMBbls**
Hibernia[2]	197.8	1244	50.6	1794	32.2	202
Terra Nova[2]	56.3	354	1.3	45	0.5	3
White Rose[2]	45	283	76.7	2722	15.3	96
Hebron	92.4	581	-	-	-	-
West Ben Nevis	5.7	36	-	-	-	-
Ben Nevis	18.1	114	12.1	429	4.7	30
North Ben Nevis	2.9	18	3.3	116	0.7	4
Springdale	2.2	14	6.7	238	-	-
Nautilus	2.1	13	-	-	-	-
Mara	3.6	23	-	-	-	-
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
West Bonne Bay	5.7	36	-	-	-	-
Sub Total (Grand Banks)	**437.3**	**2751**	**168.9**	**5990**	**56.6**	**355**
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 (Labrador Shelf)	-	-	119.6	4244	19.9	123
Total	**437.3**	**2751**	**288.5**	**10234**	**76.5**	**478**

1 "Resources" are volumes of hydrocarbons, expressed at 50% probability of occurrence, assessed to be technically recoverable that have not been delineated and have unknown economic viability.

2 "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.

Note: Table 1 reflects initial resource estimates with revisions as appropriate and does not include produced oil and natural gas liquid volumes.

Source: C -NLOPB

Hibernia Field

The Hibernia field, discovered in 1979, is located about 315 kilometres east southeast of St. John's in 80 metres of water. A fixed production platform, consisting of a gravity-based structure (GBS) and topsides drilling and production facilities, has been installed to produce the field (Figure 3). The GBS and one of the five topsides super modules were built at Bull Arm, and the four other super modules were fabricated in Korea and Italy before being transported to Bull Arm for assembly. The platform is 224 metres tall and weighs 1.2 million tonnes and can store 1.3 million barrels of oil. The crude is transported to shore by three purpose built shuttle tankers (*Kometik, Mattea* and *Vinland*), each with 850,000 barrel storage capacity. Since October 3rd, 1998, shipments of oil from Hibernia have been off-loaded at the purpose built transshipment facility at Whiffen Head, Placentia Bay.

Figure 3 - Hibernia Gravity Based Structure (GBS)

The GBS is the first of its kind. A 15 metre thick concrete ice-wall provides protection from sea ice and icebergs. The platform is designed to withstand the impact of a six million tonne iceberg, which would statistically be expected to occur once in 10,000 years. The Hibernia development has been the cornerstone of the Province's growing oil and gas sector and has supported the expansion of local infrastructure including the construction of a heliport, marine base, pipeyard, warehouse and a platform control room training simulator.

Hibernia Production

First-oil production from Hibernia occurred on November 17th, 1997, at 1:40 p.m. The first tanker load of crude oil was off-loaded in late December, 1997. Hibernia field development was based on recoverable oil reserves of 520 million barrels and an average annual oil production rate (APR) of 110,000 bpd. In November 1997, Mobil Oil announced that it increased its estimate of Hibernia recoverable reserves from 615 to 750 million barrels and obtained an APR of 135,000 bpd. Further increases in the APR have been granted, with the latest being in 2003 when the approved rate was increased to 220,000 bpd. Since the original Hibernia Development Plan was approved in 1986, there have been six (6) amendments. In May 2006, HMDC on behalf of the partnership, filed an application for a proposed depletion scheme for the Hibernia South area, as well as a central fault block. On December 19, 2006 the C-NLOPB issued Decision Report 2006.02, Respecting an Amendment to the Hibernia Development Plan. On January 17, 2007, the provincial Minister of Natural Resources announced that the decision had not been approved noting that "There are too many important unanswered questions in the application as put forward by HMDC." The Minister concluded that she is encouraged by the commitment to develop Hibernia South and looks forward to working with the project owners to resolve the province's concerns. The latest C-NLOPB recoverable reserve estimates for Hibernia include 1.244 billion barrels of oil, 1.794 tcf of natural gas, and 202 million barrels of natural gas liquids with upside potential of 1.9 billion barrels. These estimates were issued on June 1, 2006. Further reserve changes are likely, as development and delineation drilling continues, as new reservoir data gets analyzed and improvements in recovery technologies advances. During 2006, there were a total of 28 oil producers, 17 water injectors and 6 gas injectors active in the Hibernia Field including the Hibernia and Ben Nevis/Avalon reservoirs. The field averaged 178, 352 bopd during 2006 with cumulative production of 520.8 million barrels to the end of December 2006. Over the first six months of 2007 the field averaged approximately 138,000 bopd. Cumulative field production to the end of June 2007 was 545.8 million barrels.

During 1998 the *Hibernia B-16-1* well set a Canadian daily flow rate record when it tested at 56,000 barrels of oil per day.

Record Setting Wells

During 1998 the *Hibernia B-16-1* well set a Canadian daily flow rate record when it tested at 56,000 barrels of oil per day. The previous record of 27,000 bopd was held by the Panuke field, offshore Nova Scotia. Hibernia is also breaking new ground in directional drilling. The development wells are being directionally drilled from two rigs on the GBS into the Hibernia Sandstone which lies at a depth of about 3800 metres and the Ben Nevis/Avalon Sandstone at about 2400 metres. During 1998 the *Hibernia B-16-5* well was drilled to a length of 6955 metres - setting a new Canadian record for well length. Since then Hibernia has continued to break its own records. The *B-16-10Z* well reached a length of 7260 metres and the *B-16-11* well, at 8495 metres, became the 13th longest well ever drilled. In 2004 the *B-16-36* well intercepted the Hibernia Sands at a depth of 3960 metres with a horizontal displacement of 7232 metres, establishing a world record for horizontal displacement at such a depth. In 2005, Hibernia drilled and completed a dual injection well, *Hibernia B-16 50*, which penetrated two targets through two different reservoirs. Not only was this the deepest vertical well drilled into the Hibernia reservoir at that time but it also required the installation of a state of the art annular isolation valve. The Hibernia well construction team has established itself as a world leader in extended reach drilling, and continues to prove that it can provide creative technical solutions that are required to optimize resource recovery. This experience will be critical as the team attempts to explore and develop the southern region of the field.

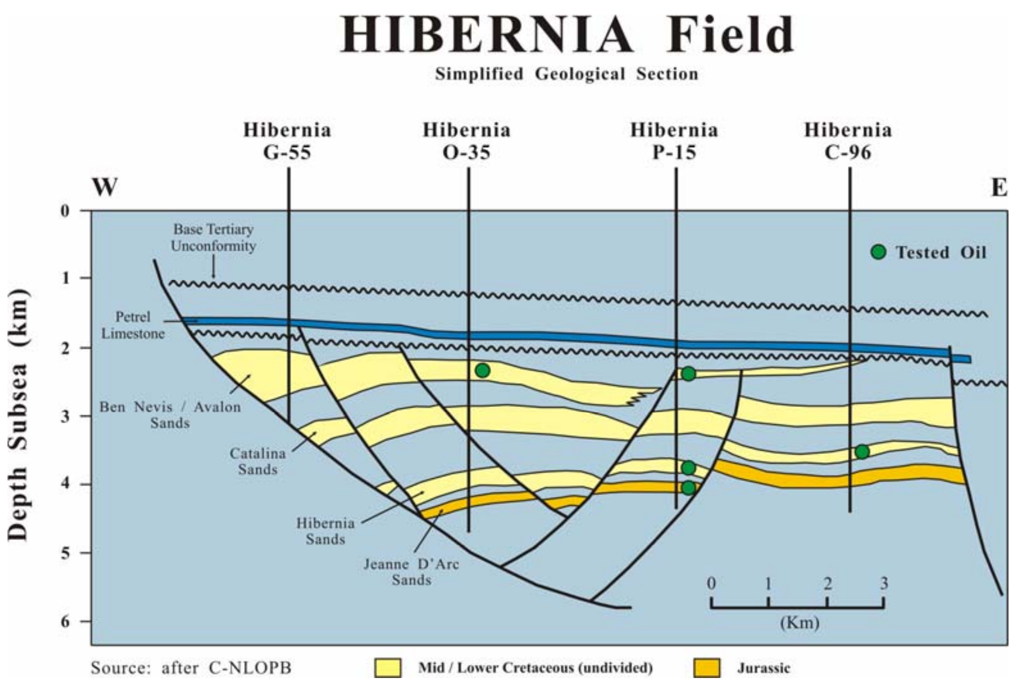


Figure 4a - Hibernia Field Geological Cross Section

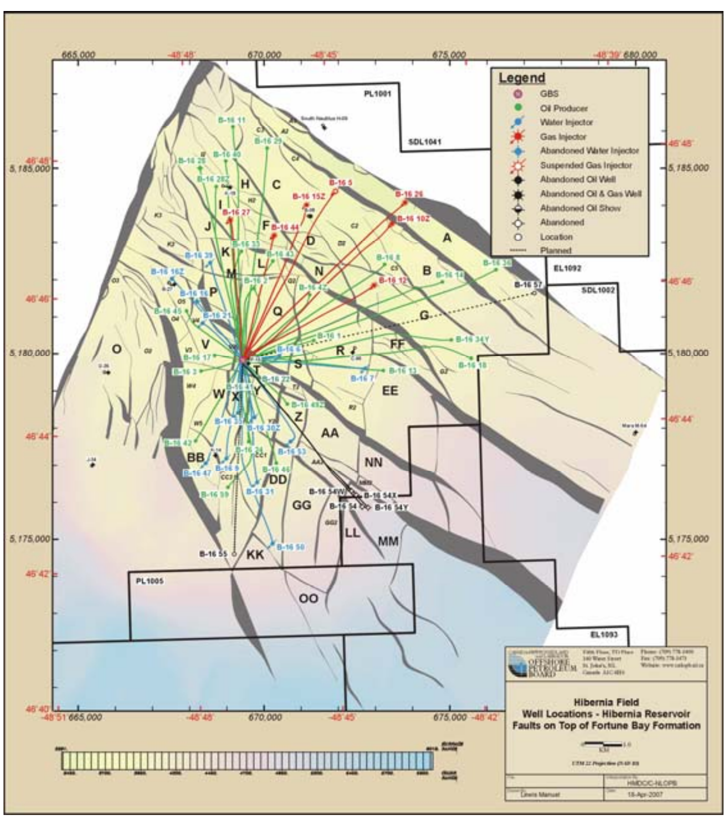


Figure 4b - Structure Map of Hibernia Reservoir

Terra Nova Field

Figure 5 - Terra Nova Floating Production Storage and Offloading Facility

The Terra Nova field was discovered by Petro-Canada in 1984 about 35 km southeast of Hibernia, in 90 metres of water. The *Terra Nova K-08* discovery well flow-tested 10,000 barrels of oil per day from the Jurassic Jeanne d'Arc Sands. Five successful delineation wells tested at rates ranging from 5,000 to 25,000 bopd. On August 4th, 2001, the FPSO (Figure 6) arrived at the field, and first-oil flowed on January 20th, 2002.

Geologically, the field consists of three fault-defined blocks designated as the Graben, East Flank and Far East blocks (Figure 7a). The proponents have indicated the most likely reserves for the Graben and East Flank are 370 million barrels recoverable . Petro-Canada has submitted an exploitation plan for the Far East block resulting in the Board rendering Decision 2005.01 respecting The Amendment to the Terra Nova Development Plan in June, 2005. In its application, the operator indicated the far East Central area contains about 43 million barrels of recoverable oil. The latest C-NLOPB recoverable reserves estimates for Terra Nova are 354 million barrels of oil, 45 bcf gas and 3.2 million barrels of gas liquids. In it's 2005 year end results, Petro-Canada increased Terra Nova's recoverable reserves from 370 million barrels to 440 million barrels.

The original plan contemplated producing oil from the Graben and East Flank for the first six years at an average of 115,000 barrels of oil per day. However, based on the productive capacity of the wells, the C-NLOPB has allowed production rates to be increased to 180,000 barrels per day. The development plan contemplates 14 producing wells and 10 injection wells in the Graben and East Flank with individual wells expected to produce in excess of 200,000 bopd. The expected life of the field is about 14 years but it could be extended depending on drilling results and oil prices. During 2006, and the first half of 2007 there were four injectors, one oil producer and one delineation well drilled and placed in service.

Figure 6 – Terra Nova FPSO

For the first half of 2007, active wells included 15 oil producers, 8 water injectors and 3 gas injectors. In 2005, the Terra Nova FPSO underwent a major turnaround in order to address reliability issues related to the gas compression system. The facility was operating at 90 percent reliability subsequent to the turnaround activity prior to experiencing mechanical problems with both the port and starboard main power generating units. The FPSO shut down production on May 7, 2006 and sailed to dry dock. The additional living quarters module that was fabricated at Bull Arm, NL was lifted to the FPSO on July 21, 2006. After leaving dry dock, the work was finalized at dock side prior to the return voyage on September 13. The vessel arrived on site on September 25, reconnected to the spider buoy and recommenced production on November 12. During early December, a routine inspection discovered a problem with the water injection swivel in the turret affecting the ability to operate the water injection system. Temporary repairs have allowed the system to continue to operate until permanent repairs can be completed.

Due to the lengthy shut-down, the field averaged 37, 495 bopd during 2006 with a cumulative production of 177.4 million barrels. Over the first six months of 2007 the field averaged approximately 121,000 bopd. Cumulative field production to the end of June 2007 was 199.3 million barrels.

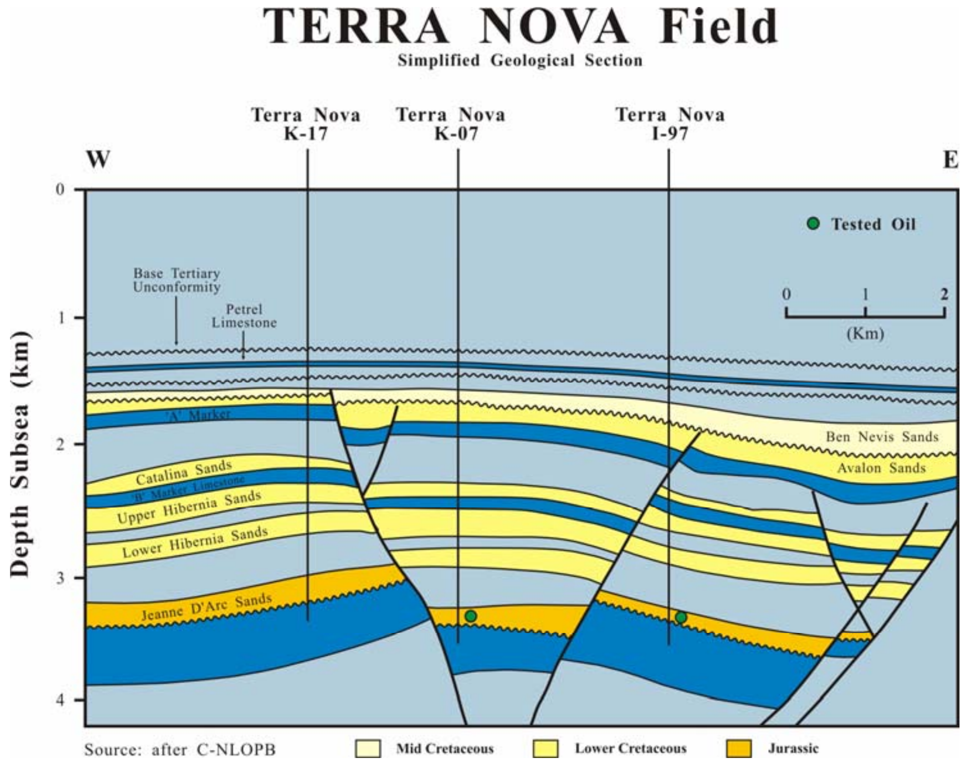


Figure 7a - Terra Nova Field Geological Cross Section

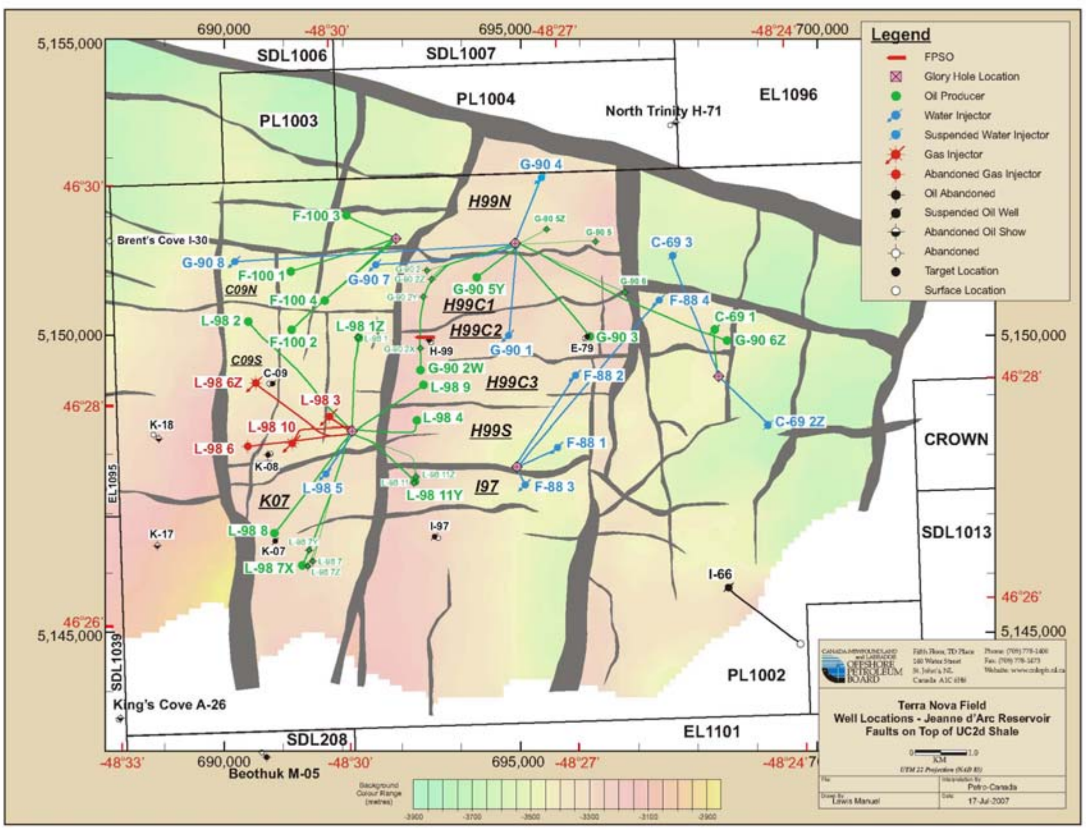


Figure 7b - Structure Map of Jeanne d'Arc Reservoir

White Rose Field

In 1984, the *White Rose N-22* discovery well tested at 900 bopd, 25 million cubic feet per day of natural gas and 840 bpd of condensate. During 1987-88, the *White Rose E-09* delineation well encountered 94 metres of net oil pay and tested at 5,000 bopd and 4 million cubic feet per day of natural gas from the Avalon Sandstone. In addition, the *J-49* delineation well flowed oil at 3,000 bopd and gas at 10 million cubic feet per day; and the *L-61* delineation well tested gas at 24 million cubic feet per day and condensate at 436 bpd.

Three appraisal wells were drilled at White Rose during 1999 which resulted in the C-NLOPB increasing its resource estimates for the field from 178 to 283 million barrels of oil; 1.51 tcf to 2.7 tcf of natural gas; and from 58 to 96 million barrels of natural gas liquids. The *White Rose H-20* delineation well drilled in May-June 2000, encountered less pay than expected and prompted Husky to reduce its recoverable oil estimate for the South White Rose pool from 255 million to 230 million barrels. On January 15th, 2001, Husky submitted a development plan application proposing White Rose development by FPSO. On March 28th, 2002, Husky and its partner Petro-Canada announced their decision to proceed with the project and production began from the White Rose field November 12, 2005.

Figure 8 - Sea Rose FPSO

As part of the White Rose South development, glory holes were completed in the summer of 2003 and development pre-drilling began in October 2003 utilizing the semi submersible *Glomar Grand Banks* using a "batch drilling process". The *White Rose F-04* well drilled in the summer of 2003 in a previously undrilled fault block at the south end of the field hit 180 metres of hydrocarbon pay, including 40 metres of gas pay and 140 metres of oil pay. A subsequent sidetrack drilled from the same well bore hit the pay zone 1100 metres to the east and confirmed the results. Husky estimates that this pool contains 200-250 million cubic feet of gas and 60-90 million barrels of oil in place, of which 20-30 million barrels would be recoverable.

The "Sea Rose" FPSO (Figure 8) has a storage capacity of 940,000 barrels oil and was approved to handle up to 100,000 bopd. The ice strengthened double hull was completed in South Korea and final fabrication, installation and commissioning of topsides was completed at the Cow Head Fabrication Facility in Marystown. The topsides consist of modules that process and treat oil, gas and water, generate power, inject water into the producing reservoir and reinject gas into the North pool for gas conservation. When commissioning was completed on November 12th, 2005, first oil was processed on the Sea Rose. The Heather Knutsen took delivery of the first oil cargo consisting of approximately 600, 000 barrels on December 5th, while the Jasmine Knutsen took delivery of approximately 940,000 barrels on December 17th.

The Sea Rose was tested to 125,000 bopd during July 2006. On September 29, 2006, Husky filed a Development Plan Amendment to increase the production rate. Based on subsequent testing results, the annual oil production rate was increased to 50 million barrels and the facility maximum daily production rate was approved at 140,000 bopd.

Husky has begun front end engineering design studies to tie back satellite reservoirs to the Sea Rose FPSO. The complete scope of these studies includes White Rose South Extension, North Amethyst and West White Rose Pools. This work is expected to be completed by the fourth quarter of 2007. An amendment to the original White Rose Development Plan is currently being reviewed for a South White Rose extension tie back. A decision is expected in early August 2007. A new glory hole was completed on August 03, 2007 by the vessel Vasco de Gama in advance of the application for development of the North Amethyst Field located south east of the Sea Rose location. This part of the field is estimated by Husky to hold 66 to 120 million barrels of oil and 120-220 bcf of natural gas.

Delineation drilling in the West White Rose region continued from the 2006 program with the spudding of the well *Husky Oil et al White Rose C-30.*

2006 represented the first complete year of production for the White Rose field, producing 32.1 million barrels of oil for an average of 87,812 bopd. Over the first six months of 2007, the field averaged approximately 124,000 bopd. Cumulative field production to the end of June 2007 was 54.4 million barrels.

WHITE ROSE Field

Simplified Geological Section

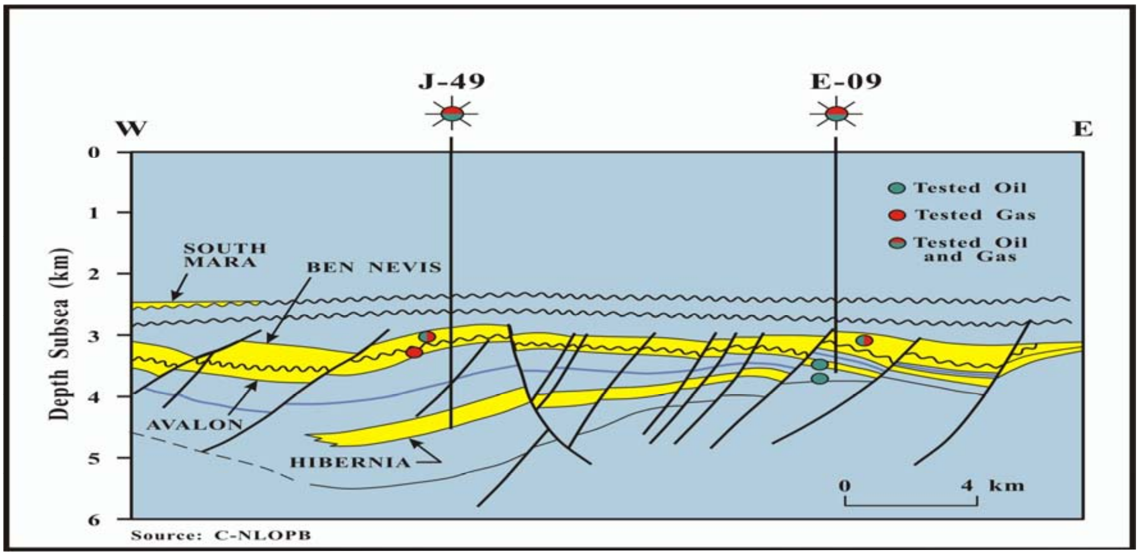


Figure 9a - White Rose Field Geological Cross Section

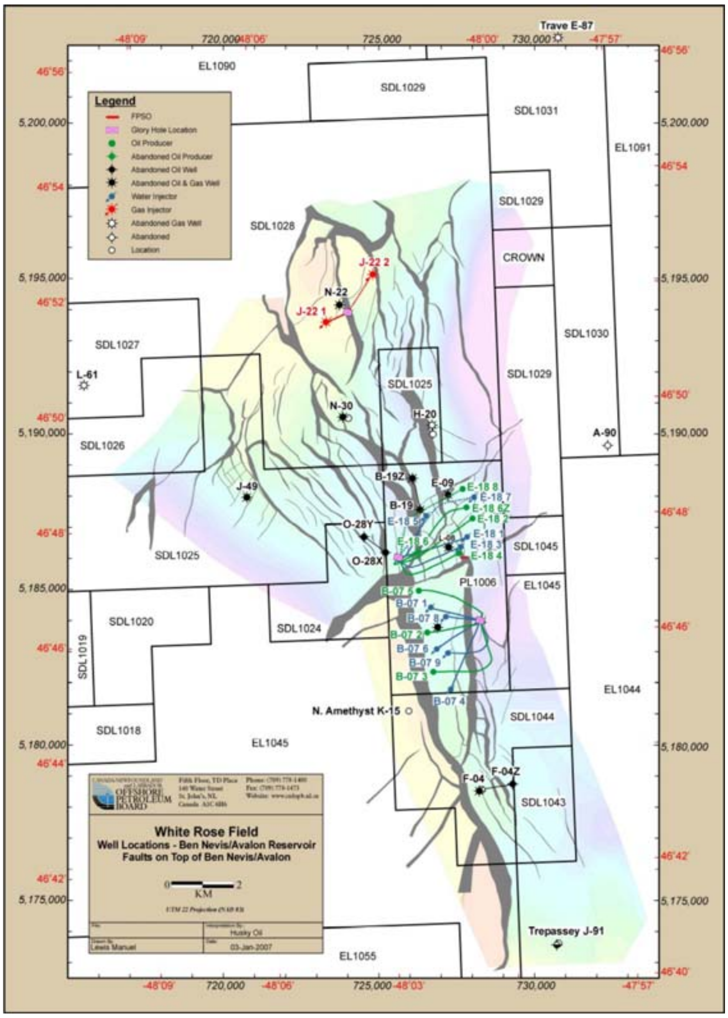


Figure 9b - Structure Map of White Rose Reservoir

Future Petroleum Developments

Hebron / Ben Nevis Complex

The *Mobil et al Hebron I-13* discovery well, drilled in 1981 in about 94 metres of water, recovered hydrocarbons from five intervals with a combined flow rate of 9,070 bopd. The Ben Nevis field (discovered in 1980) and West Ben Nevis field (discovered in 1984) are located in fault blocks that lie to the northeast and adjacent to Hebron. During 1999, the *Hebron D-94* delineation well encountered 86 metres of net oil pay in a 92 metre interval within the Ben Nevis Sandstone. A representative flow test from the 1,842 to 1,908 metre interval recovered 21 degree API oil at a rate of 3,500 barrels per day. A second delineation well, *Chevron et al Ben Nevis L-55*, tested 1,150 bopd of 30 degree API oil from a 71.3 metre pay interval. An additional delineation well, *Hebron M-04 ,* drilled in the Spring of 2000 tested 2,250 bopd and 1.6 mmcf/d of natural gas from the Jeanne d'Arc Sandstone.

On the basis of the 1999 drilling results, the C-NLOPB increased its resource estimates for Hebron from 195 million barrels to 325 million barrels; Ben Nevis, from 19 to 55 million barrels; and West Ben Nevis from 25 to 34 million barrels On June 1, 2006, the C-NLOPB revised its estimates for the Hebron/Ben Nevis Complex. The reserve estimate is now 731 million barrels of oil, 429 bcf of natural gas and 30 million barrels of natural gas liquids. Because of the close proximity of the smaller Ben Nevis and West Ben Nevis fields, they would very likely be part of any Hebron development. Chevron has announced that it has evaluated several options for field development, including an FPSO with subsea wells; a new generation GBS; and an FPSO with a wellhead platform; and a subsea tieback. On February 13th, 2002, Chevron and its partners announced they had decided to discontinue the joint evaluation of the Hebron project as the economic evaluations did not support moving forward at that time. In April 2005, the Chevron led partnership announced they had signed a unitization and joint operating agreement. The project proponents continue to evaluate this development opportunity with a focus on the gravity-based structure, and production acceleration options, and commenced negotiations with the Province relating to fiscal terms and a benefit Plan, as a pre-requisite for approval of a Development Plan.

On April 3, 2006, Chevron Canada Limited, on behalf of itself and its co-venturers—ExxonMobil Canada, Petro-Canada, and Norsk Hydro Canada Oil and Gas Inc announced a decision to suspend negotiations and demobilize the Hebron project team.

Given the magnitude of the recoverable resource, in the current global energy situation, the Province continues to be confident in the attractiveness of this project to all involved.

Hebron / Ben Nevis Complex

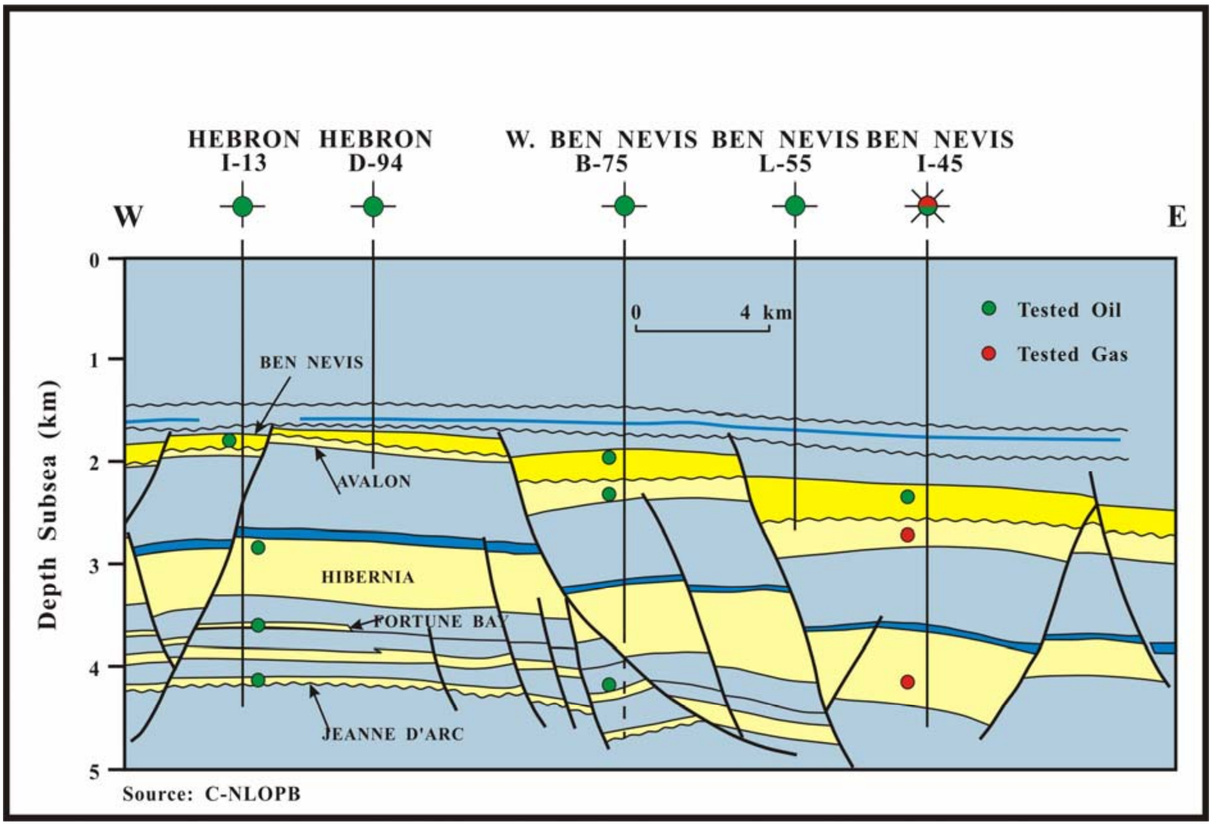


Figure 10a - Hebron/Ben Nevis Field Geological Cross Section

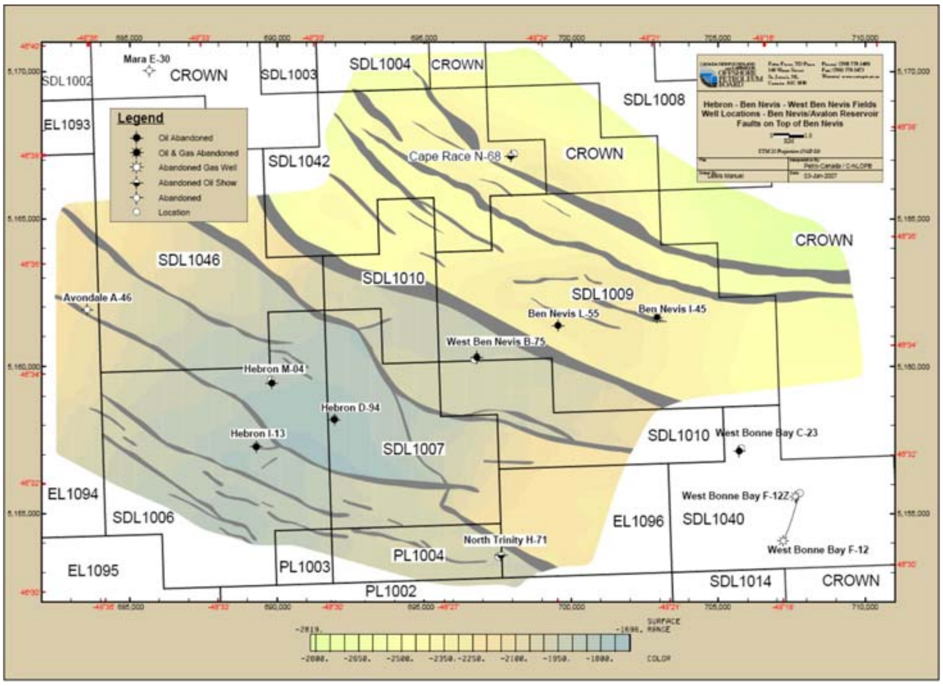


Figure 10b - Structure Map of Avalon/Ben Nevis Sandstone

Other Significant Discoveries

Grand Banks

Twelve additional wildcat wells within the northern Grand Banks area have encountered significant oil and/or gas shows. The most significant are *Fortune G-57,* which flowed at 6,978 bopd and gas at 8.4 million cubic feet per day, and the *North Ben Nevis P-93*, which flowed at 5,000 bopd and 18 million cubic feet of natural gas per day. Further drilling is required to determine the significance of these discoveries, but several smaller fields may be developed as satellites to the stand-alone projects.

Labrador

The C-NLOPB currently estimates the Labrador offshore area holds about 4.2 tcf of discovered gas (~44% of NL offshore total) and 123 million barrels of NGL's as presented in Table 1. These resources are located in 5 fields in the offshore Labrador Shelf region (Figure 12). The first well drilled in this area occurred in 1971, with the latest drilling occurring in 1983. There has been a total of 28 wells drilled (26 exploration and 2 delineation wells) leading to 5 SDL's being issued yielding a 19.2% drilling success.

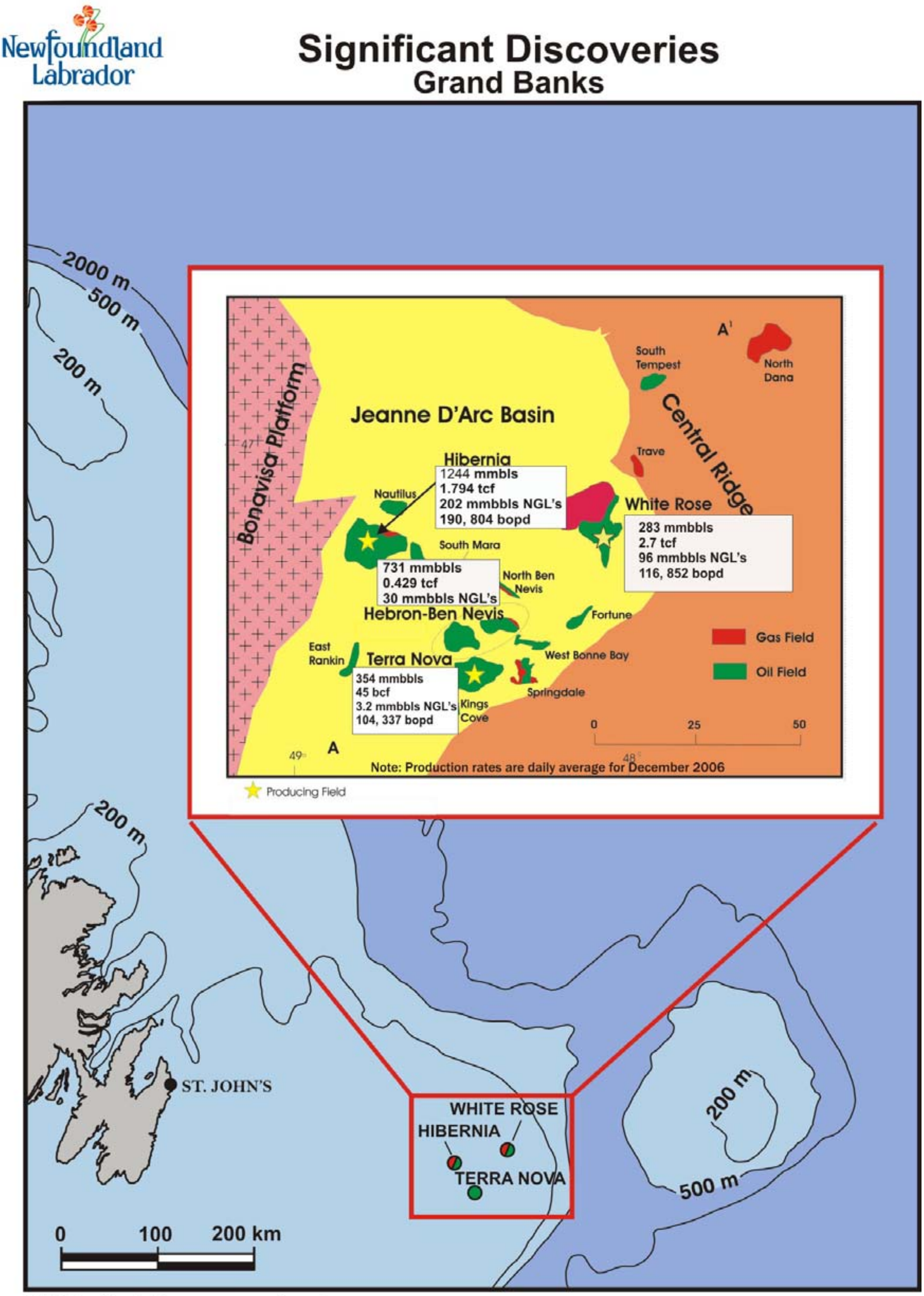
The feasibility of developing offshore Labrador's substantial gas resources has been studied by the Department of Natural Resources with the conclusion it will require certain critical technological advances, including improved pipeline trenching methods to protect against iceberg scour, and long distance multi-phase flow and metering technologies. Alternately, advancements in marine CNG technology may be a viable transportation method. Although development is not anticipated within the short term, improvements in technology and an increased demand for cleaner burning fuels may accelerate development of these resources. The Department is engaged in a 3 year Joint Industry Project with C-CORE that is focused on subsea ice risk assessment and mitigation.

Over the past five years (2001-2006) we have seen the first seismic programs acquired offshore Labrador in more than two decades. These programs have resulted in approximately 25, 260 line km of 2D data. Additional data acquisition programs are planned for 2007 and 2008. The new focus is to search for oil deposits in deepwater plays along the continental slope. These programs will help to update and strengthen the database of resource information related to this area particularly the deeper off-shelf areas where similar geological features have yielded oil seeps in the adjacent Greenland area as well as gas finds in the Davis Strait region. This is part of a worldwide trend to explore the deep water areas that has resulted in large discoveries offshore Brazil, West Africa, Gulf of Mexico and elsewhere.

Summary Comments

Offshore Newfoundland and Labrador has moved from a purely exploration frontier to the realm of significant producer. With Hibernia, Terra Nova and White Rose contributing to production, the province can expect to produce in excess of 400,000 bopd. At the same time, a critical threshold of infrastructure and technical capability is being achieved that will accelerate development of the smaller fields and is encouraging exploration. A great deal of seismic data has been acquired over the past few years which is being used to re-evaluate areas that have been ignored for more than 20 years. Advances in drilling and production technology are improving recovery factors and facilitating the exploitation of deep water areas such as the Flemish Pass, and the Laurentian and Orphan Basins. Recent seismic mapping and land sale results in the Orphan Basin have demonstrated there are very large undrilled features in our offshore area. Husky continued exploration/delineation drilling in the Jeanne d'Arc basin this year. Drilling in the Orphan Basin commenced on August 18, 2006 and the Laurentian Basin should follow. Given the amount of acreage available and the relatively sparse drilling that has occurred, the Newfoundland and Labrador offshore area remains one of great opportunity. A large new discovery in any one of these basins will lead to rapid expansion of exploration efforts.

All of these elements combine to support a continued expansion of the Province's oil and gas industry over the next several years.



NOTE: For illustrative purposes only
After: C-NLOPB

Figure 11 – Jeanne d'Arc Basin Significant Discoveries

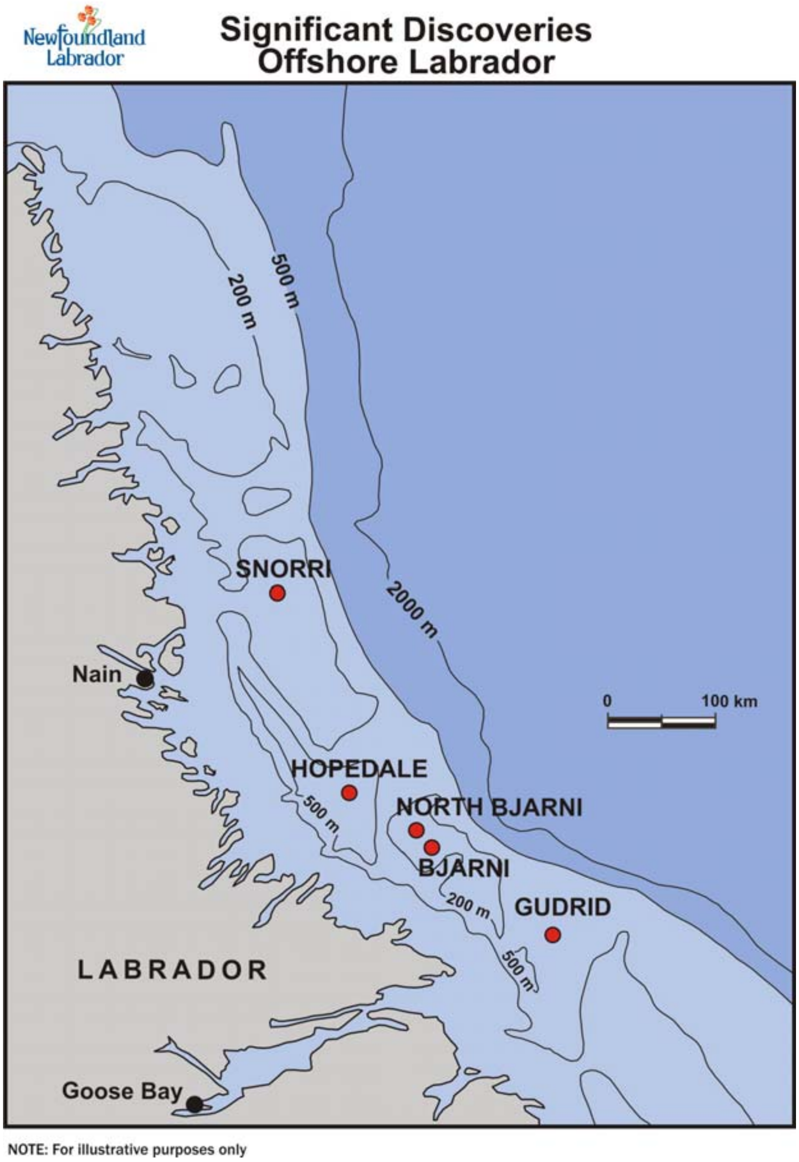


Figure 12 - Significant Discoveries Offshore Labrador

Onshore and Offshore Western Newfoundland

Approximately 1.30 million hectares of land are held under exploration licence / permit / lease to the petroleum industry in Western Newfoundland, of which 1.02 million hectares are offshore licences (under the Canada-Newfoundland Atlantic Accord Implementation Acts), and 0.28 million hectares are onshore permits and one production lease (under the Petroleum and Natural Gas Act).

The current round of exploration activity began during the early 1990's, following the release of geological reports favorable to hydrocarbon exploration in the region, the announcement of a new Royalty regime for the onshore area and the subsequent discovery in 1995 of oil and gas on the Port au Port Peninsula. In addition to onshore activity, considerable interest has also been directed offshore, within the Gulf of St. Lawrence.

At present, there are seven active exploration licences situated offshore, all of which abut on their eastern side the west Newfoundland coastline. The most northerly four licences come under NWest Energy (100%), while to the south, Licence 1069 belongs to Ptarmigan Resources (100%), Licence 1070 is held by a consortium of ENEGI Inc. (91%), CIVC Creditor Corp. (4%) and CIVC (5%). The Bay St. George licence is under the control of B.G. Capital Ltd.

Anticosti Basin—Port au Port No. 1 Discovery and Follow-up Exploration

The Hunt / PanCanadian Port au Port #1 well (at Garden Hill) spudded in September 1994 and attracted the attention of the Province and petroleum industry in the spring of 1995 when a flare from the well lit up the sky along the southwestern part of the Port au Port Peninsula. The well encountered several reservoirs, one of which was hydrocarbon bearing. Two intervals within the hydrocarbon bearing zone flowed at 1,528 and 1,742 barrels per day of high quality (51^0 API) oil and 2.6 and 2.3 million cubic feet per day of natural gas, respectively, plus associated water. An extended test on one of the intervals produced a total of 5,012 barrels of oil and 9.2 million cubic feet of gas over a nine day period. The extended test indicated the possibility of a limited reservoir or complex geology at the location. Problems associated with paraffin and salt plugging were also encountered during this extended test.

Canadian Imperial Venture Corporation (CIVC) completed a farm-in arrangement with Hunt / PanCanadian on this project in October 1999 and immediately began additional flow and pressure testing. During the summer of 2000, they completed a 26 km 2-D seismic survey over the area and followed this in 2001, by submitting a Development Plan Application which proposed to delineate and produce the Garden Hill field in phases. Under Phase 1, CIVC hoped to achieve production from the original wellbore and to drill a sidetrack well towards the northwest, targeting the up-dip portion of the Garden Hill structure. Unfortunately, the sidetrack well (Port au Port sidetrack #1) which was drilled in 2001 did not encounter commercial hydrocarbons.

On April 3rd, 2002, a production lease was granted by Government to CIVC, thereby allowing them to commence production from the lease area.

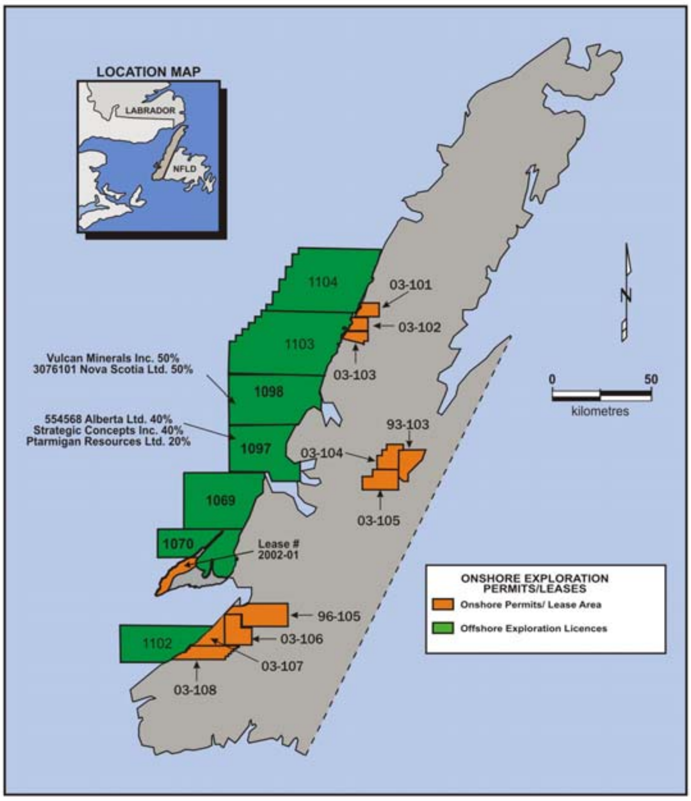
CIVC drilled a second sidetrack well (Port au Port sidetrack #2) towards the northeast during the summer of 2002. This well terminated in close proximity to the original well and flowed 195 bopd and 1.2 million cubic feet per day of natural gas with no produced water reported. During 2003 CIVC experienced financial difficulties that affected operations at Garden Hill and sought court protection from their creditors. As a result, CIVC transferred a 95% interest in the Garden Hill Lease to CIVC Creditor Corporation in July 2004. Their offshore interests were also transferred to the CIVC Creditor Corporation at that time. Under the terms of a court approved Plan of Arrangement, a third party investor (Alliance Energy Corporation), through a farm-in arrangement, committed to an exploration and production program on the Western Newfoundland properties totaling some $20 million. In May 2005 pursuant to a Mutual Release Agreement, Alliance Energy was released of all obligations, rights or future claims with respect to their commitments under the farm-in arrangement. Following this setback, CIVC assessed the situation in order to determine what steps had to be taken to find a new partner, keeping in mind commercial production had not yet commenced and CIVC Creditor Corp. had until August 2006 to resume production under the terms of the lease.

On March 31, 2006 CIVC announced that pending approvals from the Department of Natural Resources and the TSX Venture Exchange, a series of linked transactions had been negotiated and signed, between CIVC, CIVC Creditor Corp., ENEGI Inc., PDI Production Inc., Gestion Resources Limited and Alan Minty, whereby CIVC under a complicated series of terms and conditions, as well as cash and stock transfers would be able to re-acquire 100% interest in the onshore Garden Hill Production Lease and offshore Exploration Licences. Details of these arrangements are available on the CIVC website at www.canadianimperial.com. On June 28, 2006, Government issued, subject to various terms and conditions, a one year extension to the cessation of production clause associated with the lease, providing the Company with an opportunity to resume operations on the lease lands. During this period, CIVC also received final approval from the TSX Venture Exchange for its Share Exchange Agreement to acquire ENEGI Inc. The lease extension allowed CIVC and its partners time to achieve production and formulate future exploration plans. In this regard, PDI Production Inc. (PDIP) was named, on behalf of the interest holders, as the operator at Garden Hill and they commenced well re-entry operations on December 7, 2006. Production was achieved on January 18th, 2007 and initial testing up to February 5th averaged 312 barrels per day of $50^0 – 56^0$ API oil and approximately one million standard cubic feet of gas per day. A second pressure build-up and extended open hole flow test was commenced shortly thereafter, but this program was suspended in early March due to, according to PDIP, erratic flow at surface stemming from a downhole blockage. PDIP is currently assessing the situation and have devised a number of options to eliminate the problem and put the well into production.

Elsewhere on the Port au Port Peninsula, Hunt / PanCanadian spudded the onshore to offshore Long Point M-16 well at the tip of Long Point in September 1995 and followed this in May 1996 by commencing the St. George's Bay A-36 offshore well approximately six kilometers to the southwest of the Port au Port Peninsula. Both wells were deemed non-commercial, however the offshore A-36 well did contain zones of good to excellent vuggy and cavernous porosity plus bitumen and minor live oil showings within previously identified reservoir horizons. Within the same timeframe, in February 1996 Talisman et al. spudded the onshore to offshore Long Range A-09 well approximately 3 km south of the Port au Port #1 well. Unfortunately, the anticipated Aguathuna Formation reservoir zone penetrated in Port au Port #1 was water bearing in this well. No further drilling activity took place until late 1998, when Inglewood Resources commenced the onshore to offshore Man O'War I-42 well near Campbell's Creek on the southern Port au Port Peninsula. This well experienced numerous drilling related problems and had to be terminated before reaching its planned target depth. The I-42 well was quickly followed in February 1999 by the onshore to offshore Shoal Point K-39 well, drilled by PanCanadian Petroleum and partners Hunt Oil, Mobil and Encal. It was directionally drilled from an onshore location to a depth of 3035 metres to test a large structure located beneath Port au Port Bay. On May 26th, 1999, PanCanadian announced that the well had tested water and would be abandoned. In the fall of 2000 Memorial University's Earth Science Department acquired additional seismic data in the Shoal Point area that suggests the well may have missed the target. The area has since been licenced by Canadian Imperial Venture Corp. (CIVC). Shoal Point Energy Ltd., as operator for CIVC have proposed another onshore to offshore well for late 2007 to attempt to reach this identified target.

Within the Anticosti Basin of western Newfoundland, other areas besides the Port au Port Peninsula were targeted by petroleum companies during this latest round of exploration activity. In May 1997, Delpet /Vinland spudded the Big Springs #1 well near Croque on the Northern Peninsula. Only minor gas shows were encountered and this well was subsequently plugged and abandoned. Further to the south, CIVC spudded the Indian Head #1 exploration well in the Stephenville area during December 2001. No hydrocarbons were encountered and the well was at first suspended and then abandoned at a depth of 804.6 metres. In January 2004 Contact Exploration of Calgary commenced the Parsons Pond #1 well to test a large thrusted feature identified on seismic data acquired by Labrador Mining and Exploration in the mid-90s. This was the first well drilled in this area since 1965. Several companies, including Deer Lake Oil and Gas and Vulcan Minerals, partnered with Contact in this well, which was drilled on a permit acquired in the land sale that closed on December 13th, 2002. On April 12th, 2004, the well was cased and suspended after encountering minor shows in fracture zones. No plans have been announced to deepen the well, but seismic data shows the presence of deeper targets at the location.

Tekoil and Gas Corporation has entered a farm-in agreement with Ptarmigan Resources and have proposed to drill an onshore to offshore well for late 2007. This well will be drilled just north of the Port au Port peninsula in order to validate Ptarmigan's Exploration Licence # 1069 and extend it into its secondary term.



NOTE: For illustrative purposes only

Figure 13 - Western Newfoundland Petroleum Rights, August 2007

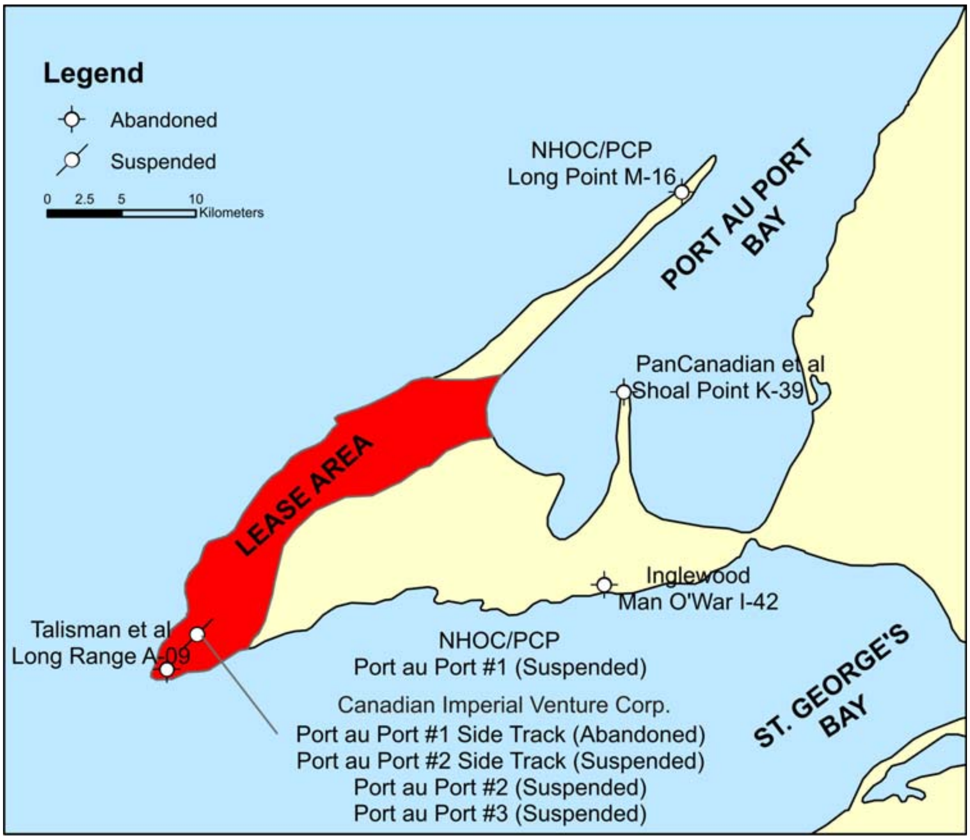


Figure 14 - Well Locations Port au Port

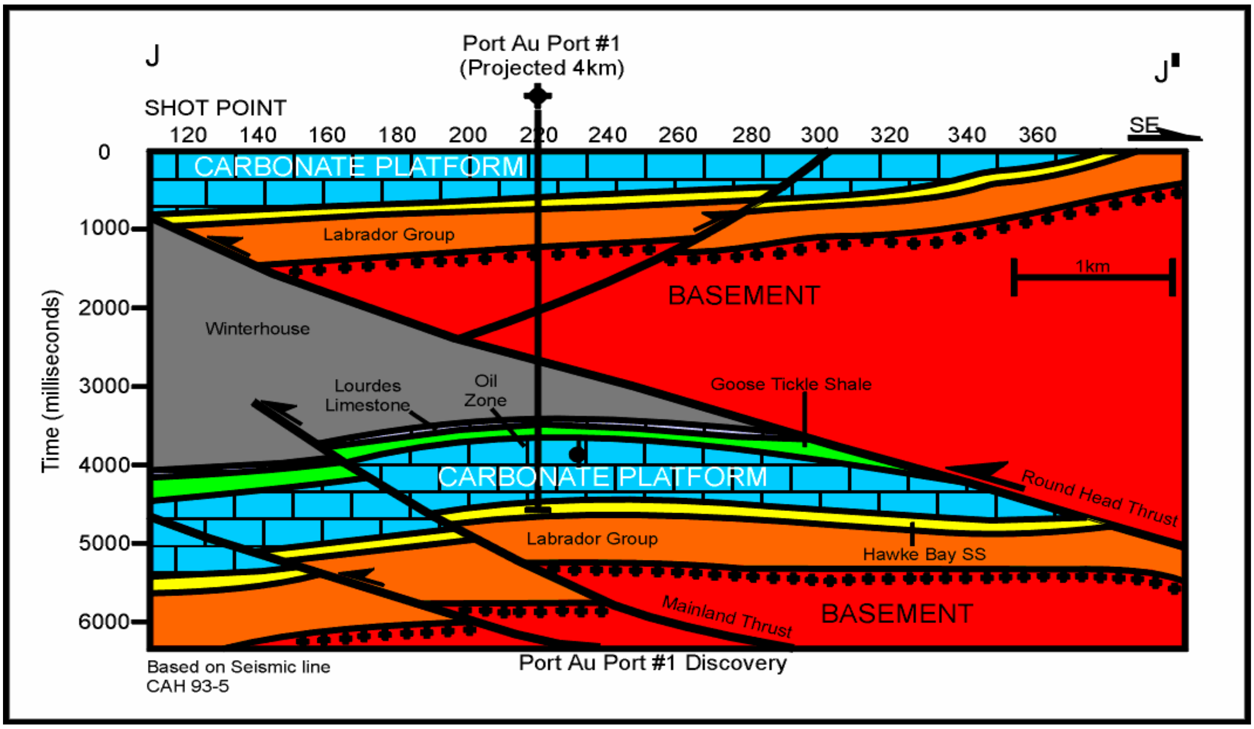


Figure 15 - Port au Port Geological Cross Section

Bay St. George Sub-basin

During 1996, the province also saw activity from several of the junior companies holding petroleum rights in the Bay St. George sub-Basin. Sandhurst Roxana of Tulsa, Oklahoma, shot 72 km of seismic data along roads in the Flat Bay area in June (Figure 17). In November 1996, London Resources Inc. drilled a stratigraphic (test) core hole adjacent to an oil-bearing mining hole originally drilled for gypsum in the Flat Bay area during the mid 1950s. The test hole encountered oil-bearing conglomerate at 138 metres and was still within the oil-bearing section when it was suspended at 154 metres "for possible future re-entry and analysis". In 1998, Newfoundland based Vulcan Minerals recorded a 6 km seismic line in the Flat Bay area, in preparation for drilling in 1999.

On August 10th, 1999, Vulcan Minerals spudded a 300 metre well at Flat Bay, onshore western Newfoundland to test a Carboniferous conglomerate target that was proven to contain live oil by the 1996 London Resources test hole. The well was drilled by a cable tool rig and on September 16th, 1999, Vulcan announced that the well had encountered "significant oil shows over a gross interval exceeding 100 metres". The company also indicated the geophysical logs indicate zones that may be commercially productive upon stimulation of the reservoir. The well was suspended at a depth of 286 metres.

Following upon the success of Vulcan Minerals, American Reserve Energy Corporation (AREC) of Tulsa, Oklahoma, drilled a well to the east of the Vulcan Flat Bay site during 2000-01. This well encountered oil within fractured anhydrite, but it had to be terminated, prior to entering a potential reservoir zone, due to drilling problems. In 2004, Vulcan Minerals drilled their 835m Flat Bay #2 well immediately adjacent to the AREC well. The company reported the well encountered a low permeability oil zone (in excess of 100 metres) in the same formation as the Flat Bay #1 oil show.

Vulcan Minerals Inc. spudded the Captain Cook #1 well in the Flat Bay area on December 19th, 2001. On January 30th, 2002, Vulcan announced the well had reached total depth and no commercial hydrocarbons had been encountered. Vulcan also acquired 19 km of seismic data in the Flat Bay area during January 2002 and completed a 60 km seismic program in December 2004.

Vulcan re-entered the cable-tool Flat Bay #1 well in early March 2004, conducted a completion program and hydraulically fractured a 5-metre interval. The operator is still assessing the results, as well as proceeding with exploration.

In 2005, Vulcan Minerals Inc. continued to be very active. The company had by early summer completed the purchase of a petroleum drill rig (Ingersoll Rand RD 10 top drive unit) and proceeded to put down four holes in the Bay St. George area before the end of the year. Three of these four holes (Storm #1, Backstretch #2 and Whip #1) were located over new prospect areas as identified from previous seismic surveys, while the fourth (Flat Bay #3) was put down in close proximity to the original Flat Bay #1 petroleum discovery hole. All wells, except Storm #1 had oil and/or gas shows, primarily in the form of cuttings fluorescence or anomalous gas detector readings. The hydrocarbon shows as seen in the Whip #1 and Backstretch #2 wells, although minor, are significant because they indicate an active petroleum system approximately 15 to 20 km to the south of the original Flat Bay #1 discovery. To further evaluate their land holdings, Vulcan also conducted a 70 line kilometer Vibroseis ground seismic survey and completed an Airborne aeromagnetics survey over their entire land holdings.

Based on their previous drilling results and seismic data in combination with the 2005 aeromagnetic survey, Vulcan re-assessed their exploration strategy for 2006 and targeted two structures for their exploration program. In late October, Flat Bay #5 was drilled as a further test of the oil bearing Flat Bay structure, however upon completion, the Company announced that the well would be plugged and abandoned. The second well Red Brook #1 targeted an area approximately 20 km to the southwest of the original Flat Bay structure. This well encountered drilling related problems and according to Vulcan, "the well has been suspended at a depth less than the targeted horizon". Therefore, the Red Brook target is still untested, with re-entry and completion to be determined at a later date.

Vulcan is continuing its exploration activities in the Flat Bay area and in July 2007 received approval for a 56 km 2D seismic program on their three Exploration Permits in the Flat Bay area.

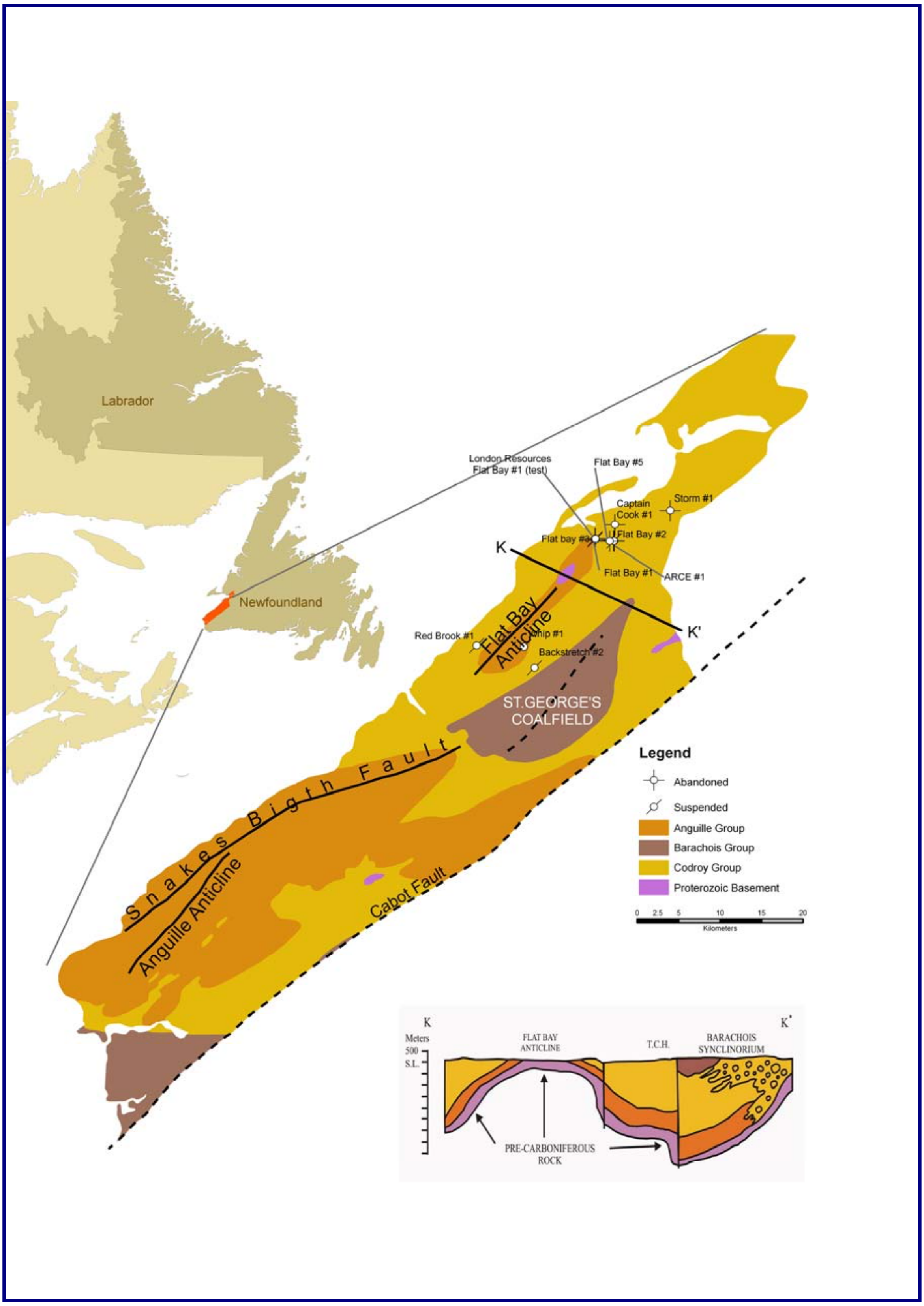


Figure 16 - Bay St. George Well Locations and Geological Cross Section

Deer lake Basin

In 2000-2001, Deer Lake Oil and Gas (DLOG) drilled the 1879 metre Western Adventure #1 well in the Deer Lake Basin. This well had a condensate show at 850 metres and flowed gas on drillstem test at a rate of 100,000 cubic feet per day at 1600 metres. DLOG had indicated that it planned to do further testing on this well. In the fall of 2002, DLOG drilled the Western Adventure #2 well in the Deer Lake Basin. This well is reported to have "encountered gas shows in porous and fractured zones at several levels". Based on drillstem results from Western Adventure #1, DLOG submitted a Development Plan Application to Government on March 11, 2003. In June 2005 the Company re-entered the Western Adventure #1 well and two upper zones were perforated and tested but there was no hydrocarbon flow to surface. The well is currently suspended as the Company evaluates the results of the testing program. In May 2006, Deer Lake Oil and Gas announced, that while undertaking routine ground reconnaissance and structural geology studies in the Basin, a Company prospector observed a live oil seep within EP 2003 105. This ground show is to the southwest of all previous drilling activity undertaken in this region. Also in 2006, DLOG submitted on September 19th an updated Development Plan Application for the Western Adventure Field. The updated Application outlines the additional work which has to be done by the Company in order to eliminate work deficiencies noted by Government in the original 2003 Development Plan Application.

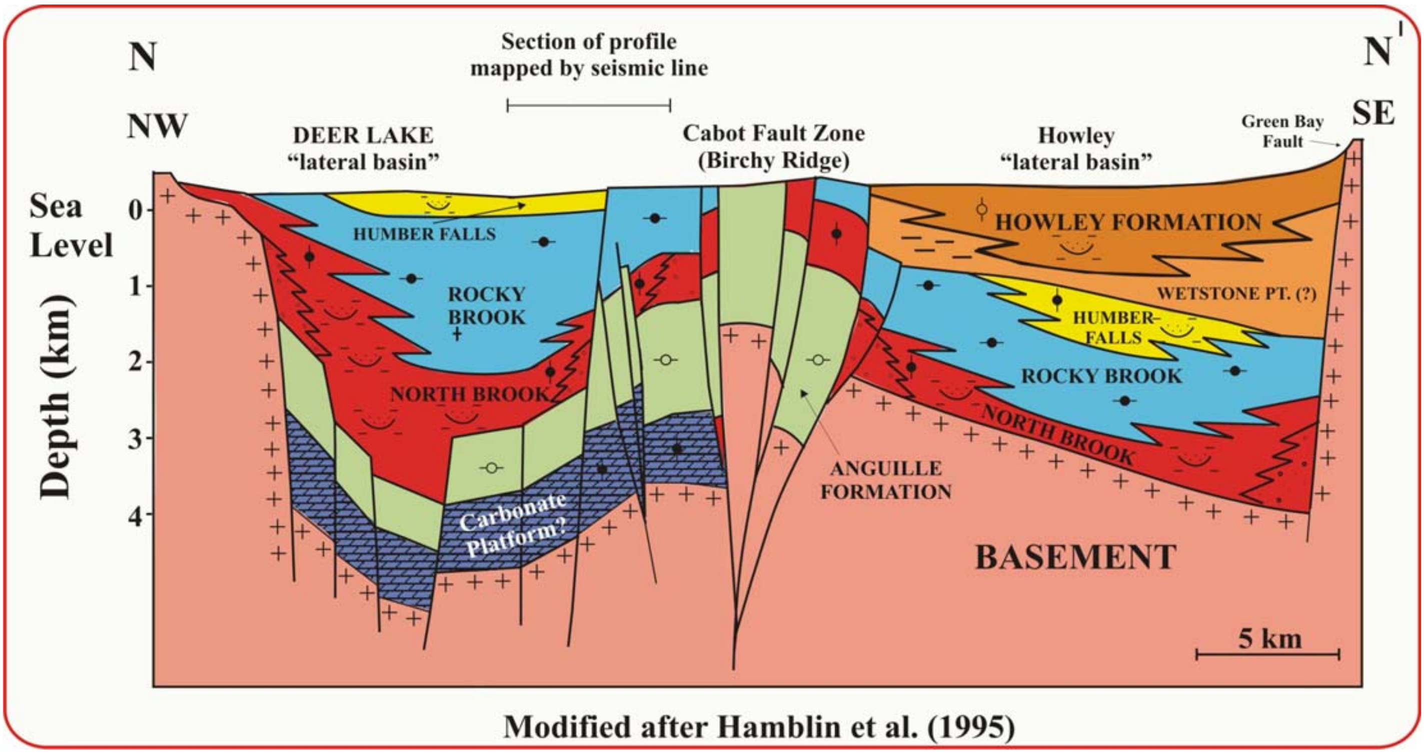


Figure 17 - Deer Lake Basin Geological Cross Section

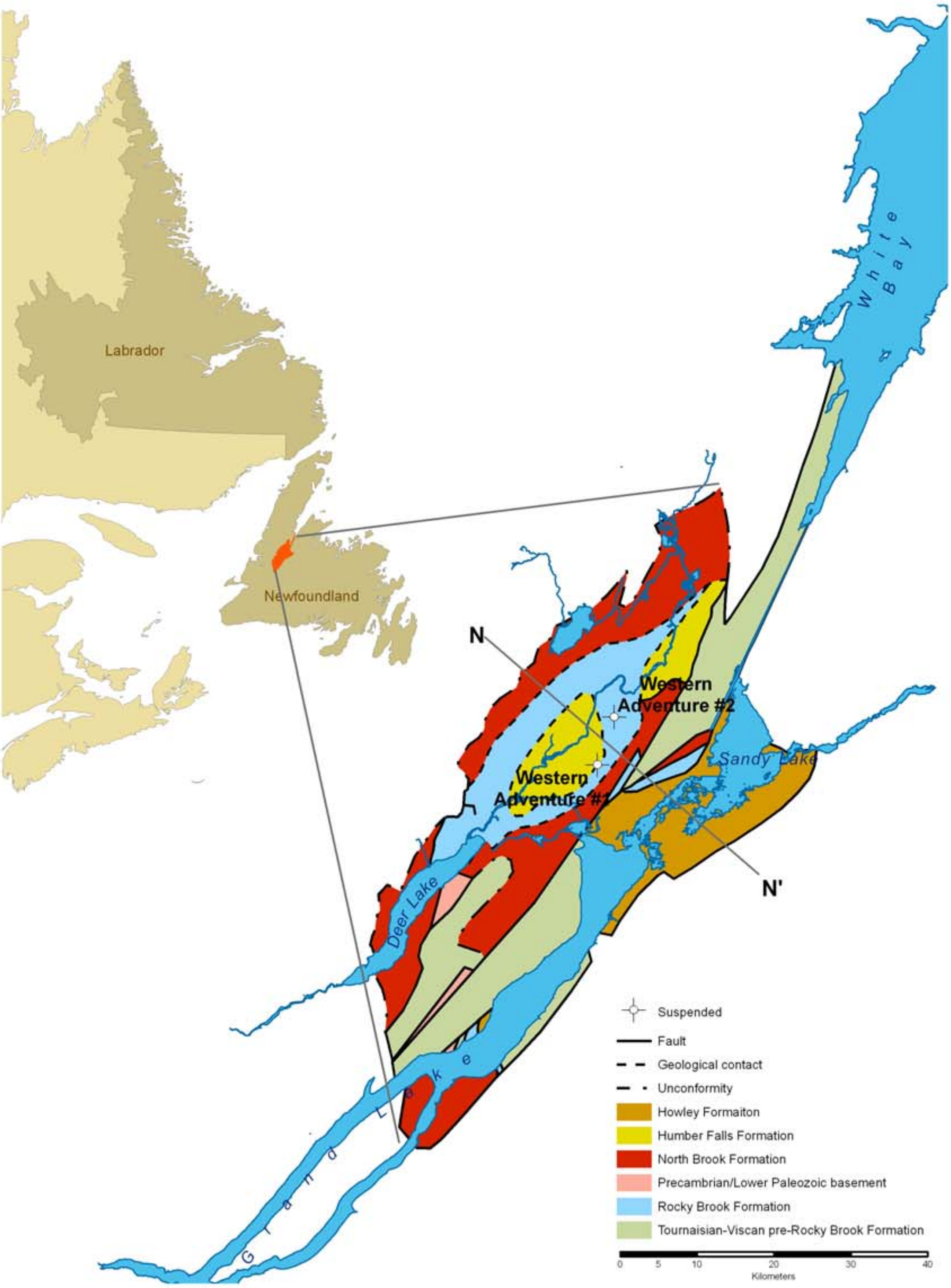
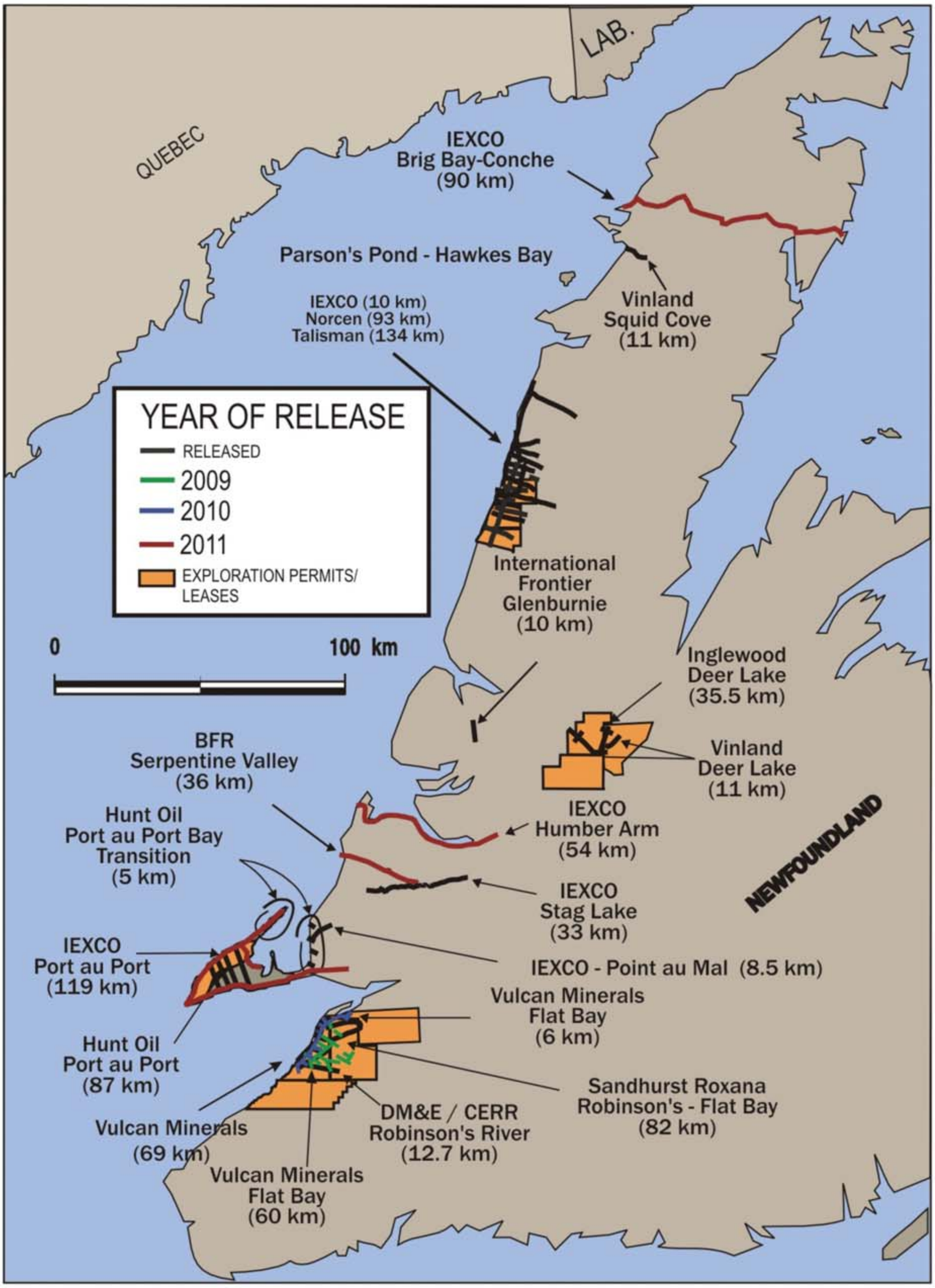


Figure 18 - Well Locations Deer Lake Basin



NOTE: For illustrative purposes only

Figure 19 - Onshore Western Newfoundland Reflection Seismic Lines

Transshipment Facility

Figure 20 - Whiffen Head Site: Onshore and Marine Facilities

The Newfoundland Transshipment Limited (NTL) terminal located at Whiffen Head, Placentia Bay commenced operations on October 1, 1998. Crude oil is shuttled from the Hibernia and Terra Nova fields to the NTL terminal. From there the crude oil is transported to market by smaller conventional tankers, capable of accessing ports along the eastern seaboard of the US and the Gulf of Mexico. The terminal provides several advantages to the offshore oil industry, including reducing the number of shuttle tankers needed to service the offshore fields; and, providing greater marketing flexibility by allowing the size of shipment to be tailored to the buyer's needs.

The Terminal has been operated since 1998 by IMTT-NTL, Ltd. on behalf of NTL, and has a workforce of 43 in Whiffen Head, including tug crews, all of whom are dedicated and skilled local personnel. The terminal has operated for over nine years without a lost time or serious environmental incident

Newfoundland Transshipment Limited (NTL) is an independent company formed to construct and operate the facility. The facility presently has two berths and loading platforms and six floating roof storage tanks with 500,000 barrels capacity each, for a total of 3.0 million barrels capacity.

North Atlantic Refinery

The North Atlantic Refining Limited oil refinery located at the head of Placentia Bay, has a rated capacity of 105,000 barrels of oil per day and crude and product storage for over 7 million barrels. In addition, the deep water facility is capable of receiving ultra large crude carriers up to 300,000 dwt directly at the dock. While some of the refinery's output is sold in the province, most is marketed in the Northeastern United States.

On January 3rd, 2001, an agreement was reached between North Atlantic Refining and Petro-Canada to allow North Atlantic Refining to market their products throughout Canada.

In 2004, the North Atlantic Refinery saw the completion of a butane storage facility and other upgrades aimed at producing ultra-low sulphur gasoline and diesel. Since purchasing the refinery in 1994, refinery owners Vitol, have invested in excess of $600 million.

In 2005, Vitol announced its decision to sell all or part of its interest in the refinery. On August 23, 2006 Harvest Energy Trust announced that it had entered into an agreement to acquire the refinery and related business from Vital Refining Group B.V. on October 19, 2006 Harvest announced that the acquisition was finalized.

Figure 21 - Come-By-Chance Oil Refinery

Fiscal Systems

Generic Offshore Royalty Regime

Basic Royalty	
until earliest of: (i) 20% of reserves (ii) 50 million barrels (mmbls) (iii) Simple Payout	1%
(i) 100 mmbls cumulative production (ii) Simple Payout	2.5%
next 100 mmbls	5%
thereafter	7.5%
Net Royalty	
Tier 1 Rate Return Allowance	 20% 5% plus LTGBR*
Tier 2 Rate Return Allowance	 10% 15% plus LTGBR*

The royalty is comprised of a basic royalty component and a net royalty component. The basic royalty component is an ad valorem type royalty applied to the value of petroleum production. The net royalty is profit-based and, consequently, is a progressive royalty.

This royalty system is sensitive to the costs, risks and challenges associated with exploration and development in the Newfoundland and Labrador offshore, and is competitive with other jurisdictions.

An independent consultant has advised the regime is competitive on a worldwide basis, ranking in the top half when compared with other national and international regimes.

The Basic Royalty is payable from the very first barrel of oil produced from a petroleum project and is payable on each and every barrel produced thereafter. The Basic Royalty rate applicable is phased in as certain levels of production are achieved (see table). If the project achieves Simple Payout (point in time when the costs related to the particular project are recovered) prior to 100 million barrels of production the Basic Royalty rate automatically increases to five per cent.

Net Royalty commences to be payable upon the occurrence of Net Royalty Payout. When costs are recovered and the Tier 1 Return Allowance is achieved, the Tier 1 Net Royalty rate becomes applicable. The Basic Royalty paid is applied as a credit against any Tier 1 Net Royalty payable and, as a result, royalties payable for any particular period would be the greater of the Basic Royalty or the Tier 1 Net Royalty.

When the Tier 2 Return Allowance is achieved, the Tier 2 Net Royalty rate becomes applicable. The Tier 2 Royalty is in addition to any other royalties payable.

Generic Onshore Royalty Regime

Royalty Holiday	
First 2 million barrels	
Basic Royalty	
5%	
Net Royalty	
Tier 1 Rate Return Allowance	 20% 5% plus LTGBR*
Tier 2 Rate Return Allowance	 5% 15% plus LTGBR*

There is no royalty payable on the first two million barrels or equivalent of production for a project. After two million barrels of production, a Basic Royalty of five percent is payable.

Net Royalty commences to be payable upon the occurrence of Net Royalty Payout. When costs are recovered and the Tier 1 Return Allowance is achieved, the Tier 1 Net Royalty rate becomes applicable. The Basic Royalty paid is applied as a credit against any Tier 1 Net Royalty payable and, as a result, royalties payable for any particular period would be the greater of the Basic Royalty or the Tier 1 Net Royalty.

When the Tier 2 Return Allowance is achieved, the Tier 2 Net Royalty rate becomes applicable. The Tier 2 Net Royalty is in addition to any other royalties payable.

The Province is also close to finalizing a natural gas royalty regime.

* Long Term Government Bond Rate

Department of Natural Resources

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