CANADA-NEWFOUNDLAND
OFFSHORE
PETROLEUM
BOARD

DECISION 2003.01

RESPECTING

THE AMENDMENT
TO THE
HIBERNIA DEVELOPMENT PLAN

March 2003

Disponible en francais

ISBN # 0-921569-92-0

Table of Contents

Page

List of Tables

List of Figures

Preface

On October 11, 2002, the Hibernia Management and Development Company (HMDC) submitted an application to increase the Hibernia field annual production rate from 28 600 m^3/d (180,000 b/d) to 35 000 m^3/d (220,000 b/d). The effect of this proposal would be to increase the authorized maximum annual production from about 10.4 million cubic metres (65.6 million barrels) to 12.8 million cubic metres (80.4 million barrels). The Canada-Newfoundland Offshore Petroleum Board (the Board) deemed HMDC's (the Proponent's) request to be an application to amend the Hibernia Development Plan previously approved by the Board. The Board's approval of such an amendment is a Fundamental Decision pursuant to the Accord.

In support of the application, the Proponent submitted the document ***Technical Support For Hibernia Field Rate Increase September 2002****. The technical information provided was based, in part, on development of the Ben Nevis/Avalon reservoir.*

The Board's Decision 97.01 required the Proponent to provide a report detailing the Ben Nevis/Avalon appraisal program results and a Development Plan for the Ben Nevis/Avalon reservoir by December 31, 2002. In a report of December 13, 2002, entitled ***Ben Nevis/Avalon Program Update****, the Proponent noted that many of the essential elements necessary for preparing a comprehensive development plan for the Ben Nevis/Avalon reservoir remain unknown and requested a three-year extension of the appraisal period to December 31, 2005. Further, the Proponent requested that the Ben Nevis/Avalon appraisal activity be allowed to continue while the Proponent's application to extend the appraisal period is being considered.*

The requests to extend the Ben Nevis/Avalon appraisal period and the Ben Nevis/Avalon Development Plan submission to December 2005 are in their own right Fundamental Decisions. The Proponent has been requested to supply additional information to support such decisions.

Following a review of the support document ***Technical Support For Hibernia Field Rate Increase September 2002*** *and subsequent discussions, the Proponent was advised that, the application to increase the Hibernia field's annual oil production rate from 28 600 m^3/d (180,000 b/d) to 35 000 m^3/d (220,000 b/d), was inclusive of a Ben Nevis/Avalon reservoir development, and since the Proponent had also requested an extension to the appraisal period for this reservoir, the application could not be consider in the form submitted.*

On December 20, 2002, the Proponent submitted the document ***Technical Support For Hibernia Field Rate Increase, Revision 1****, which provided for limited Ben Nevis/Avalon reservoir development and based the Hibernia field rate increase proposal almost wholly on increased production from the Hibernia reservoir. Hence, December 20, 2002, became the effective date of the Proponent's application for a rate increase; it is now the subject of this Decision Report.*

1.0 Summary:

The subject of this Decision Report is the submission by the Hibernia Management & Development Company (HMDC) on December 30, 2002 of its document *Technical Support for Hibernia Field Rate Increase, Revision 1*. That document requests approval to increase the Hibernia field annual production rate from 28 600 m^3/d (180,000 b/d) to 35 000 m^3/d (220,000 b/d). The requested increase is based almost wholly on increased production from the Hibernia reservoir, with limited development of the Ben Nevis/Avalon reservoir.

The documentation, including associated reservoir simulation files, provides a reasonable basis on which to assess the Proponent's request. The Proponent advises that the supporting technical work demonstrate that ultimate recovery is insensitive to field production rates. Further, the Proponent notes that full field reservoir simulations were run with platform rates restricted to 28 600 m^3/d (180,000 b/d) and 35 000 m^3/d (220,000 b/d), honoring all physical and resource management constraints that are currently in place. According to the Proponent, no significant impact to oil recovery was observed between the simulation cases.

The Application has been reviewed to determine whether the proposed production rate increase would affect the environmental impact predictions made in the Hibernia Environmental Impact Statement or commitments in the Hibernia Benefits Plan, or any of the conditions established in Decision Reports 86.01, 90.01 and 97.01 and 2000.01. Because the Application involves only a change to the annual oil production rate approved in Decision 2000.01, and does not involve any major modification to the facilities themselves, it does not affect the approved Hibernia Benefits Plan. It appears, based on information provided by the Proponent, that daily water production may exceed the currently approved daily rates and this issue has been addressed in this Decision Report. Otherwise, the conclusions of the Environmental Impact Statement and the conditions of previous Decisions are unaffected. The Board's Chief Safety Officer has also considered how higher rates might affect the safety of operations and has concluded that the equipment and procedures in place can safely handle the higher rates. In the context of the foregoing, no further public review is required.

This approval is specific to the annual oil production rate increase requested by the Proponent. It does not imply an approval of any extended Ben Nevis/Avalon appraisal program, which is the subject of a separate application and will be a Fundamental Decision. It is acknowledged as part of this Fundamental Decision that the depletion scheme now provides for possible increased water injection and increased produced water volumes, conversion of certain water flood fault blocks to gas flood or gas storage, and for possible miscibility in gas flood blocks. If the Proponent elects to pursue any of these initiatives appropriate approvals must be first sought. If the initiative involves substantial modification or additions to existing production facilities, this will constitute an amendment to the Development Plan and as such will be a Fundamental Decision.

Based on its assessment of the information presented, the Board concurs with the Proponent that oil recovery from the Hibernia field is not materially affected by an annual oil production rate of 35 000 m^3/d (220,000 b/d). Also, reservoir simulation studies suggest minimal effect on life of field, up to a year reduction, from the annual production rate increase. The Board notes, however, there are several opportunities to exploit additional oil reserves that have not been factored into the production forecast, which could extend the field life.

The Board has therefore approved the following:

Hibernia Development Plan Amendment
Decision 2003.01

The Board approves the Proponent's Application to increase the annual oil production rate to 35 000 m^3/d (220,000 b/d) subject to conditions 2003.01.01, 2003.01.02 and 2003.01.03, set out below, and the conditions contained in its Decision Reports 86.01, 90.01 and 97.01 and 2000.01. The outstanding conditions are summarized in Appendix A.

Under this approval, the maximum allowable annual oil production for the calendar year 2003 will be determined using the following daily average oil rates:

(a) 28 600 m^3/d (180,000 b/d) from January 1, 2003 to the day immediately preceding the day upon which the Board's approval for an increase to the annual oil production rate becomes effective pursuant to Section 32 of the Acts; and,

(b) 35 000 m^3/d (220,000 b/d) from the date that the Board's approval for an increase to that rate becomes effective pursuant to Section 32 of the Acts.

For each calendar year thereafter, the annual maximum allowable rate shall be the rate approved in (b) above.

Condition 2003.01.01
It is a condition of the Board's approval that:

> The Board's Chief Conservation Officer may at any time reduce the production rate if reservoir performance differs significantly from that predicted in the document entitled *Technical Support For Hibernia Field Rate Increase*, *Revision 1*, and the Chief Conservation Officer has reason to believe that production at the approved rate may cause waste.

Condition 2003.01.02
It is a condition of the Board's approval that:

(i) The Proponent undertake and submit to the Chief Conservation Officer no later than March 31, 2004 an analysis of the feasibility of produced water re-injection; and

(ii) The Proponent proceed with produced water re-injection if, in the opinion of the Chief Conservation Officer, it is technically feasible and economically reasonable to do so.

Condition 2003.01.03
It is a condition of the Board's approval that:

No later than 6 months prior to seeking approval for anticipated marine discharge of produced water at a daily rate in excess of 24 000 m^3, the Proponent shall:

(i) Submit, in a form suitable for public release and acceptable to the Board's Chief Conservation Officer, an assessment of the environmental effects of produced water discharge at the maximum daily discharge rate for which it anticipates seeking approval, including but not limited to:

- A description of results from modeling of the physical fate of discharged produced water at rates up to the maximum daily rate proposed;
- An assessment of the potential environmental effects of the aforementioned produced water; and
- An assessment of any resultant changes to the conclusions of the *Hibernia Environmental Impact Statement*; and

(ii) Submit for the approval of the Chief Conservation Officer revisions to the Environmental Protection Plan components of the *Hibernia Operational Plan* that are necessary in consideration of the assessment described in Condition 2003.01.03(i).

2.0 The Proponent's Application:

2.1 Background

On December 20, 2002, the Proponent submitted the document *Technical Support for Hibernia Field Rate Increase, Revision 1*, which provided for limited Ben Nevis/Avalon reservoir development that is consistent with the proposed approach to the reservoir depletion and near term production plan. A copy of the reservoir simulation files was also submitted. This information provides a reasonable basis to assess the Proponent's request to increase the Hibernia field's annual production rate from 28 000 m^3/d (180,000 b/d) to 35 000 m^3/d (220,000 b/d).

The following section of the report presents an overview of the Proponent's reservoir simulation study provided in support of its application to increase the annual oil production rate for the Hibernia field.

2.2 Proponent's Application

Drilling and Production operations at the Hibernia field the Proponent has produced a substantial quantity of data which was used by the Proponent to update it's geophysical, geological and reservoir simulation models. These models are being continuously updated to assess and predict performance, plan drilling locations and assess opportunities to improve the depletion schemes. The Proponent presented a map (Figure 1) showing the designated fault block names for the Hibernia reservoir, wells that are currently on production and planned well locations (white text). According to the Proponent the planned well locations are not definitive but are indicative of the potential areas of the Hibernia reservoir that remains to be developed. A map (Figure 2) showing the locations of existing Ben Nevis/Avalon reservoir wells was also presented. The Proponent noted that a detailed re-evaluation of the structure and geology and reservoir performance of the Ben Nevis/Avalon reservoir is in progress, from which proposed well locations will be derived from the detailed re-evaluation.

2.2.1 Original Oil-in-Place and Gas-in-Place Estimates

Original oil-in-place and gas-in-place estimates, completed in March 2002, were presented by the Proponent based on a Hibernia reservoir structural model built in 2001. The Proponent noted that prior estimates of the Hibernia oil-in-place estimates were performed in 1998 and 1999 and provided a comparison of these estimates with the current estimates (Table 1). The 2002 Petrel geological model is being upgraded by the Proponent to include the latest geological interpretation and will be up-scaled to a new reservoir simulation model. According to the Proponent, early indications are that the oil-in-place estimate from the upgraded Petrel model will confirm the oil-in-place for the 2002 Petrel model shown in Table 1. Several other geological modeling initiatives are currently in progress by the Proponent.

Table 1: Comparison of Oil-in-Place Estimates for Hibernia Reservoir, 1998, 1999 and 2002 (Source: After HMDC 2002)

Volumetric Estimate	Original Oil-in-Place, Million m^3				
	A	B Zone 1	B Zone 2	B	Total
1998 (Zmap)	21.066	44.900	140.455	185.356	206.422
1999 (Zmap)	18.857	52.301	162.054	214.355	233.212
2002 (Petrel)	18.857	43.534	192.568	236.102	254.959

Figure 1: Hibernia Reservoir Depth Structure Map Indicating Current And Planned Well Locations (Source: After HMDC 2002)

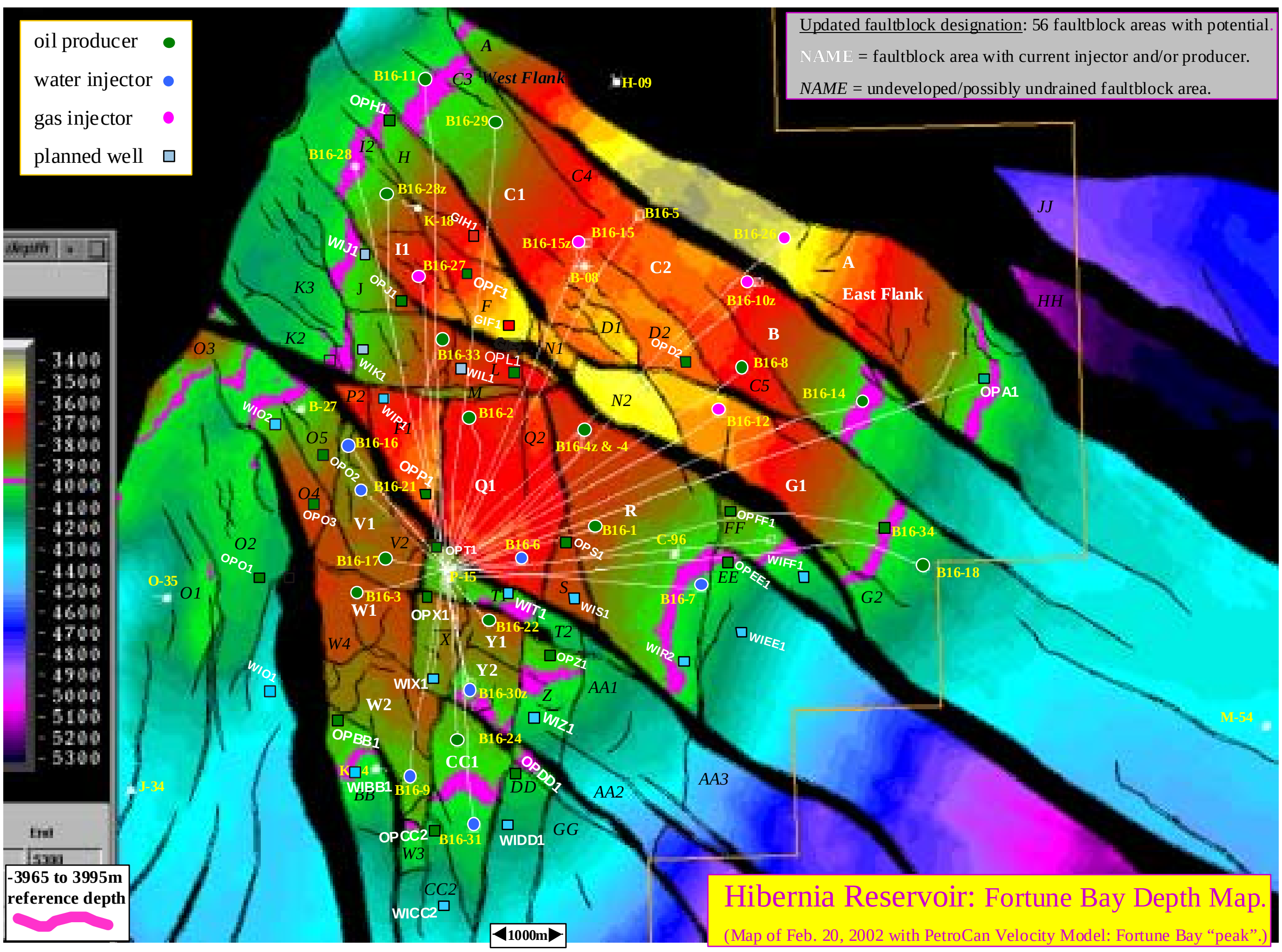
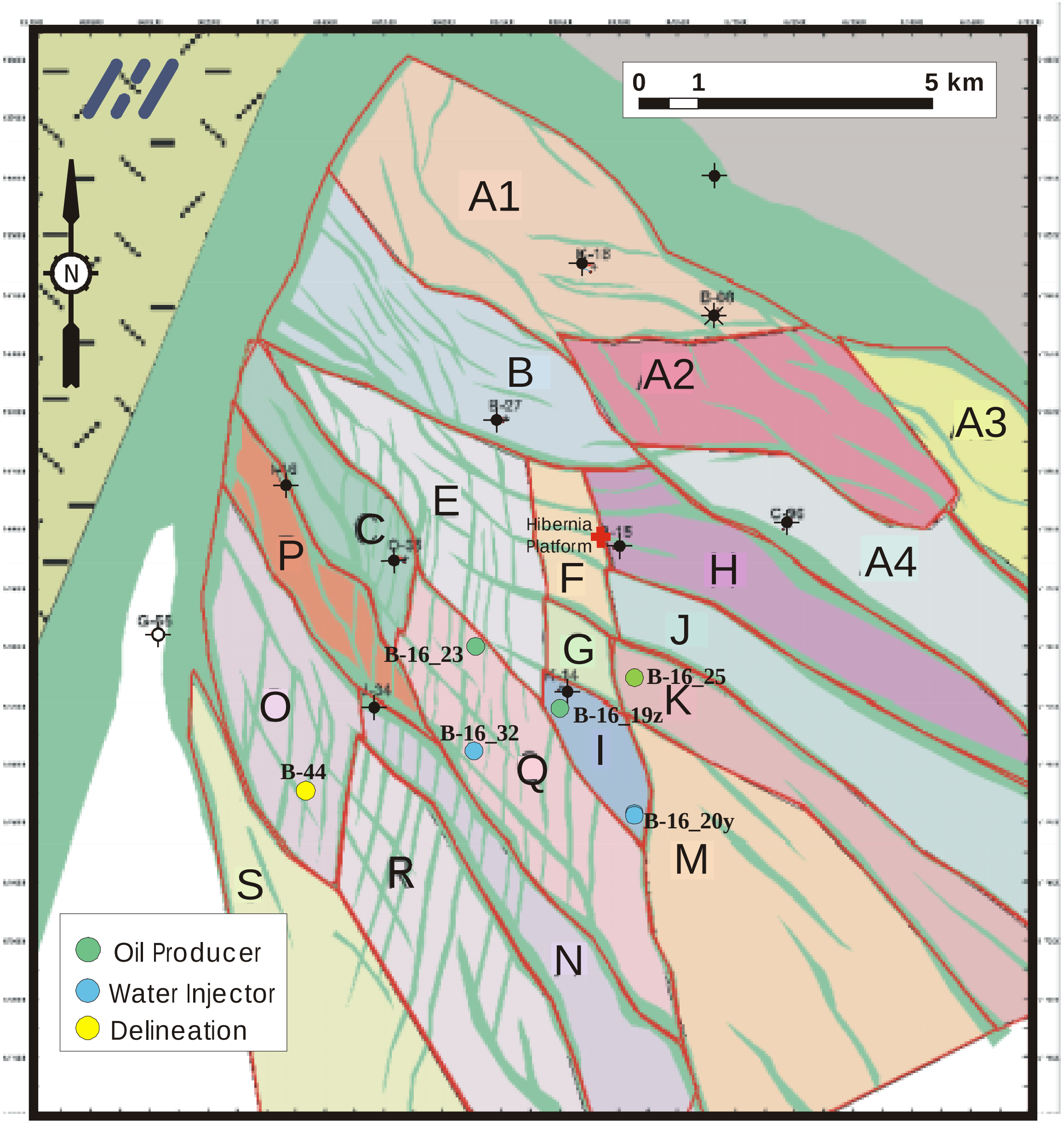


Figure 2: Ben Nevis/Avalon Reservoir Current Well Locations (Source: After HMDC 2002)

Ben Nevis/Avalon Fault Block Map



2.2.2 Reservoir Performance

The Proponent provided an overview of production and injection performance to date; a summary of the performance is provided in Table 2. Up to June 30, 2002, 31.8 million m^3 (200 million barrels) of oil has been produced with the Hibernia reservoir performance being better than expected. According to the Proponent this has been particularly true of the water flood area; notable improvement in the gas flood performance has been made.

Generally, within a fault block in the water flood area, the major reservoir intervals typically exhibit excellent lateral communication and are conducive to a two well producer/injector development. However, small-scale faulting, less than 15 metres, has been found to influence communication between producer-injector pairs within a fault block.

It is the Proponent's view that management of the gas flood area is more complex than the water flood area. Several factors contribute to the complexity of the gas flood area.

- Pressure communication exists between the B, C and G fault blocks but the precise connection pathway is unclear.
- A low mobility tar mat was encountered in the I Block producer B-16 28. There are indications that the tar mat discovered by the B-16 28 well may also be present in the G Block producer B-16 18. The presence of tar mats at or below the oil-water contact would also account for the lack of aquifer support encountered in the A, B and G Blocks and for the fact that the A and I Blocks act as isolated compartments.
- The main stratigraphic sand units tend to be more hydraulically separated (i.e. not effectively communicating) in the gas flood area, suggesting that individual units may have to be targeted to ensure an effective flood.
- The water flood is conducive to piston displacement of individual sands, which is an efficient displacement process, whereas the gas flood is more prone to gas override.

The Proponent notes that although the Hibernia reservoir water flood is theoretically a more efficient recovery mechanism than gas flood, simulation results indicate overall recovery factors are very similar. Water flood is the Proponent's preferred recovery mechanism and the minimum area necessary to accommodate solution gas produced from the water flood will be planned for gas flood.

Five wells, three producers and two water injectors, have been drilled in three separate Ben Nevis/Avalon reservoir fault blocks. While the producers have encountered reservoir quality sands, which show lateral extent, poor water injection performance has hampered the ability to provide sustainable pressure support. Efforts to remediate the poor water injection performance are being undertaken by the Proponent.

Table 2: Hibernia Production and Injection Summary (Source: After HMDC 2002)

Hibernia Production/Injection Summary

Through June 2002

	Field	Hibernia Waterflood									Gasflood									Ben Nevis/Avalon			
Production	All Blocks	Developed	R Block			Q Block	W Block	V Block	Y Block	CC Block	Developed	C Block				B Block	G Block	A Block	I Block	Total	I Block	Q Block	K Block
	All Wells	Waterflood	B-16 1	B-16 4z	Total	B-16 2	B-16 3	B-16 17	B-16 22	B-16 24	Gasflood	B-16 11	B-16 8	B-16 29	Total	B16-14	B-16 18	OPA1	B-16 28	All Wells	B-16 19z	B-16 23	B-16 25
2002																							
million m3	**5.00**	**3.22**	**0.06**	**0.98**	**1.04**	**0.68**	**0.53**	**0.68**	**0.00**	**0.29**	**1.69**	**0.08**	**0.43**	**0.28**	**0.79**	**0.62**	**0.27**	**0.00**	**0.01**	**0.09**	**0.06**	**0.02**	**0.01**
million bbls	31.5	20.3	0.4	6.2	6.5	4.3	3.3	4.3	0.0	1.8	10.6	0.5	2.7	1.8	5.0	3.9	1.7	0.0	0.1	0.6	0.4	0.1	0.1
Total																							
million m3	**31.80**	**22.83**	**5.62**	**5.57**	**11.19**	**4.26**	**4.45**	**2.39**	**0.17**	**0.38**	**8.16**	**1.94**	**1.17**	**0.28**	**3.42**	**3.34**	**1.38**	**0.00**	**0.02**	**0.81**	**0.63**	**0.14**	**0.04**
million bbls	200.0	143.6	35.3	35.0	70.4	26.8	28.0	15.0	1.1	2.4	51.3	12.2	7.4	1.8	21.5	21.0	8.7	0.0	0.1	5.1	4.0	0.9	0.3
Mapped STOIIP (March 2002)																							
	Hib.Res.																						
million m3	236.1	94.5			31.6	11.4	23.6	10.7	5.7	11.6	77.9				21.5	12.9	15.6	22.9	5.0	15.0	5.8	5.2	4.0
million bbls	1485.0	594.5			198.7	71.4	148.3	67.2	36.0	73.0	489.8				135.2	81.1	98	143.8	31.6	94.3	36.5	32.7	25.2
Actual RF@ breakthrough					20.9%	none	17.7%	17.0%	none	none					4.1%	8.8%	none	none	none				
RF Cum to date	***13.1%***	***24.2%***			***35.4%***	***37.5%***	***18.9%***	***22.4%***	***2.9%***	***3.3%***	***10.5%***				***15.9%***	***25.9%***	***8.9%***	***0.0%***	***0.4%***	***5.4%***	***10.9%***	***2.6%***	***1.1%***
Predicted Ultimate Recovery (Reservoir Simulation 220 Kstb/d case at end 2017)																							
	Hib.Res.																						
Sim. STOOIP	247.6	97.8			31.9	11.4	19.2	13.1	6.3	16.0	82.5				32.9	11.4	14.5	18.7	5.0				
million bbls	1557.4	615.2			200.5	71.6	120.5	82.2	39.6	100.7	518.7				207.0	71.5	91.2	117.4	31.6				
EUR million m3	112.1	46.9			17.9	5.1	10.3	4.0	2.9	6.7	39.5				11.9	6.2	8.7	10.5	2.2				
EUR million bbls	705.3	295.2			112.6	32.3	64.9	25.0	18.2	42.3	248.7				74.7	39.2	54.8	66.1	13.8				
RF @ breakthrough (sim. prediction)					18.1%	32.4%	21.8%	12.5%	7.7%	8.5%					3.1%	8.8%	16.0%	23.0%	16.6%				
RF Cum to date	12.8%	23.3%			35.1%	37.4%	23.2%	18.3%	2.7%	2.4%					10.4%	29.4%	9.5%	0.0%	0.4%				
Ultimate RF	**45.3%**	**48.0%**			**56.1%**	**45.1%**	**53.8%**	**30.5%**	**45.8%**	**42.0%**	**47.9%**				**36.1%**	**54.9%**	**60.1%**	**56.3%**	**43.6%**				
Injection	**Water Injection**										**Total Field Gas,Mm3 and Cscf**					**Gas Injection by Block**				**Water Injection**			
2002	**Field**	**Hibernia**									**Injection**	**Fuel**	**Flare**		**C Block**	**B Block**	**G Block**	**A Block**	**I Block**	**Ben Nevis/Avalon**			
million m3	**5.41**	**5.39**			**1.68**	**1.44**	**0.85**	**1.12**	**0.00**	**0.31**	**1,127.1**	**80.1**	**48.2**		**341.8**	**393.2**	**180.8**	**174.9**	**36**	**0.02**	**0.00**	**0.02**	**0.00**
million bbls	34.0	33.9			10.6	9.0	5.4	7.0	0.0	1.9	39.8	2.8	1.7		12.1	13.9	6.4	6.2	1.3	0.1	0.0	0.1	0.0
Total																							
million m3	**36.59**	**35.84**			**17.35**	**7.21**	**7.32**	**3.66**	**0.00**	**0.31**	**6,620.5**	**569.2**	**1,440.5**		**2,360.6**	**2,584.2**	**1,140.4**	**457.9**	**77**	**0.75**	**0.73**	**0.02**	**0.00**
million bbls	230.1	225.4			109.1	45.3	46.0	23.0	0.0	1.9	233.8	20.1	50.9		83.4	91.3	40.3	16.2	2.7	4.7	4.6	0.1	0.0

Note: "Hib. Res." column 2 includes underdeveloped blocks, all other STOOIP, EUR, RF numbers are for development blocks.
RF for Hibernia "Field" excludes Ben Nevis/Avalon

2.2.3 Reservoir Simulation Model

The Proponent provided a detailed description of the factors considered and parameters used to construct the Hibernia field reservoir simulation model, which is used to assess performance under various depletion schemes and operating conditions.

2.2.3.1 Development Well Drilling Sequence

There are two drilling units, east and west rigs, on the Hibernia platform. Due to this drilling limitation, a key component in constructing the reservoir simulation model was the development of a well drilling sequence. The Proponent undertook a comprehensive assessment to develop a drilling sequence for the Hibernia and Ben Nevis/Avalon development wells. According to the Proponent, the following steps were taken.

- Determine rank order of Hibernia and Ben Nevis/Avalon reservoirs' fault blocks based on oil-in-place, productivity, risk and appraisal value.
- Assign block developments by rig.
- Determine block developments to be included in each scenario. Higher risk, lower reserve developments in the ranking were excluded.
- Generate well sequence by rig.
- The Proponent's drilling staff validated well to rig allocation and provided a well schedule for input to simulation based on drill days, workovers, rig non-productive time, bi-annual shutdown.

In addition, the Proponent presented an overview of assumptions used to generate the well drilling schedules.

- Drilling performance, which considers past drilling performance and provided for non-drilling time.
- Directional drilling planning, drilling slot assignments, slot utilization and slot recovery.
- Modeling of slot constraint, in as much as even where Ben Nevis/Avalon reservoir development is unsuccessful, more than 64 wells are required, while only 64 drill slots are located at the Hibernia platform.
- Near term depletion strategy.

The Proponent's proposed base drilling schedule which provides for no further development of the Ben Nevis/Avalon reservoir is provided in Figure 3 while a drilling schedule accounting for limited Ben Nevis/Avalon development is provided in Figure 4. Recovery of slots will be an important factor for any Ben Nevis/Avalon reservoir development noted by the Proponent. The reservoir simulation model accounted for this factor.

Figure 3: Base Drilling Schedule. "Hibernia Reservoir Success – No Further Ben Nevis/Avalon Development Scenario" (Source: After HMDC 2002)

East (M71) Rig

On Stream Date	Well Name	Measured Depth, m	Drill Days	Allocated Non-drill Days	Cumulative Drill Days from 1/1/02	slot count
5-Apr-02	OPC2				94	12
6-Aug-02	WIY1				217	13
15-Jan-03	OPG2	7889	162	0	379	14
16-Jul-03	OPA1	9511	183	11	561	15
13-Sep-03	OPX1	4100	60	11	620	16
25-Dec-03	OPFF1	6100	92	11	723	17
30-Mar-04	GIF1	5600	85	11	819	18
30-Jul-04	WIFF1	7000	111	11	941	19
6-Dec-04	OPD2	5800	97	32	1070	20
24-Feb-05	OPBB1	4700	69	11	1150	21
15-May-05	OPS1	4400	69	11	1230	22
17-Aug-05	WIBB1	5500	83	11	1324	23
8-Nov-05	WIS1	4900	72	11	1407	24
3-Feb-06	OPCC2	5200	76	11	1494	25
24-Apr-06	OPDD1	4700	69	11	1574	26
20-Jul-06	WICC2	5200	76	11	1661	27
5-Nov-06	WIDD1	5200	76	32	1769	28
14-Jan-07	OPT1	4000	59	11	1839	29
27-Apr-07	OPEE1	6100	92	11	1942	30
4-Jul-07	WIT1	3900	57	11	2010	31
3-Nov-07	WIEE1	7000	111	11	2132	32

West (M72) Rig

On Stream Date	Well Name	Measured Depth, m	Drill Days	Allocated Non-drill Days	Cumulative Drill Days from 1/1/02	slot count
22-Feb-02	**WICC1**				52	17
4-May-02	AWIQ1				123	18
13-Jul-02	OPK1				193	19
6-Oct-02	OPI2				278	19
23-Dec-02	WIX1	4500	66	12	356	20
30-Mar-03	WIK1	5700	86	12	453	21
12-Aug-03	OPH1	7500	123	12	588	22
7-Nov-03	OPO1	5100	75	12	675	23
31-Jan-04	OPL1	5000	74	12	760	24
9-May-04	WIO1	5800	88	12	859	25
2-Aug-04	WIL1	5000	74	12	944	26
16-Nov-04	OPO2	5000	74	33	1050	27
19-Feb-05	WIO2	5500	83	12	1145	28
11-May-05	OPO3	4700	69	12	1226	29
17-Jul-05	OPP1	3800	56	11	1293	30
20-Oct-05	OPJ1	5500	83	12	1388	31
3-Jan-06	WIP1	4400	65	11	1463	32
17-May-06	WIJ1	7000	111	12	1597	33
8-Sep-06	OPZ1	4700	69	32	1711	34
16-Dec-06	WIZ1	5100	75	11	1810	35

West Rig slot constrained

Color Key

Hibernia Water flood well

Hibernia Gas flood well

Ben Nevis - Avalon well

Black text - wells on stream as per Drilling Schedule

White text - wells deferred by slot constraint, on stream dates per simulation model

Figure 4: Drilling Schedule For Sensitivity Case - Limited Ben Nevis/Avalon Development After 2003 - 2005 Appraisal Period (Source: After HMDC 2002)

East (M71) Rig

On Stream Date	Well Name	Measured Depth, m	Drill Days	Allocated Non-drill Days	Cumulative Drill Days from 1/1/02	slot count
5-Apr-02	OPC2				94	12
6-Aug-02	WIY1				217	13
15-Jan-03	OPG2	7889	162		379	14
16-Jul-03	OPA1	9511	182	11	561	15
13-Sep-03	OPX1	4100	59	11	620	16
26-Dec-03	AWIK1	5900	104	11	724	17
7-Apr-04	OPFF1	6100	103	11	827	18
12-Jul-04	GIF1	5600	96	11	923	19
2-Dec-04	WIFF1	7000	143	32	1066	20
20-Mar-05	OPD2	5800	108	11	1174	21
8-Jun-05	OPBB1	4700	80	11	1254	22
27-Aug-05	OPS1	4400	80	11	1334	23
29-Nov-05	WIBB1	5500	94	11	1428	24
20-Feb-06	WIS1	4900	83	11	1511	25
11-Jun-06	AOPN1	6400	111	11	1622	26
6-Sep-06	OPCC2	5200	87	11	1709	27
16-Jan-07	AWIN1	6400	132	32	1841	28
13-Apr-07	WICC2	5200	87	11	1928	29
2-Jul-07	OPDD1	4700	80	11	2008	30
10-Sep-07	OPT1	4000	70	11	2078	31
6-Dec-07	WIDD1	5200	87	11	2165	32
26-Sep-10	WIT1	3900	81	11	2246	33
12-Jan-11	OPP1	3800	80	11	2326	34
4-Mar-11	OPZ1	4700	93	11	2419	35
2-Jul-11	WIP1	4400	109	32	2528	36
19-Nov-11	WIZ1	5100	99	11	2627	37
11-Mar-12	OPEE1	6100	116	11	2743	38
24-Jul-12	WIEE1	7000	135	11	2878	39

East Rig slot constrained

West (M72) Rig

On Stream Date	Well Name	Measured Depth, m	Drill Days	Allocated Non-drill Days	Cumulative Drill Days from 1/1/02	slot count
22-Feb-02	WICC1				52	17
4-May-02	AWIQ1				123	18
13-Jul-02	OPK1				193	19
6-Oct-02	OPI2				278	19
23-Dec-02	WIX1	4500	78	12	356	20
30-Mar-03	WIK1	5700	97	12	453	21
12-Aug-03	OPH1	7500	135	12	588	22
7-Nov-03	OPO1	5100	87	12	675	23
6-Feb-04	AOPQ2	5300	91	12	766	24
15-May-04	WIO1	5800	99	12	865	25
3-Sep-04	AWIQ2	6300	111	12	976	26
18-Dec-04	OPO2	5000	106	33	1082	27
13-Mar-05	OPL1	5000	85	12	1167	28
16-Jun-05	WIO2	5500	95	12	1262	29
9-Sep-05	WIL1	5000	85	12	1347	30
29-Nov-05	OPO3	4700	81	12	1428	31
11-Apr-06	AOPO1	7300	133	12	1561	32
1-Aug-06	AOPQ4	6200	122	12	1683	33
3-Feb-07	AWIO1	7900	186	33	1869	34
18-May-07	AWIQ4	5300	104	12	1973	35
14-Aug-07	AOPB1	4200	88	12	2061	36
31-Dec-08	AOPO2	6800	138	12	2199	37
26-Nov-10	AWIB1	5300	104	12	2303	38
12-Aug-11	AWIO2	7600	180	33	2483	39
18-Oct-11	OPJ1	5500	108	12	2591	40
3-Apr-12	WIJ1	7000	136	12	2727	41

West Rig slot constrained

Color Key

Hibernia Water flood well
Hibernia Gas flood well
Ben Nevis - Avalon well

Black text - wells on stream as per Drilling Schedule
White text - wells deferred by slot constraint, on stream dates per simulation model

2.2.3.2 Full Field Model Inputs Assumptions and Constraints

To assess and predict performance of the Hibernia and Ben Nevis/Avalon reservoirs, the Proponent constructed a reservoir simulation model consisting of 80,000 active cells and 16 simulation layers. The model was history matched i.e. parameters in the model were adjusted such that the model prediction matched actual performance. The Proponent notes that the Hibernia reservoir model has been upgraded since the start of production. The Ben Nevis/Avalon reservoir model has not been upgraded because its development has proceeded at a slower pace. Further, the Proponent notes that although the Ben Nevis/Avalon reservoir representation is less precise than the Hibernia reservoir representation, it is a fundamental part of the Hibernia field development and needs to be included to accurately represent the impact of facility constraints. A new Ben Nevis/Avalon reservoir model is being built. The Proponent provided a comprehensive overview of the inputs, assumptions and constraints used to construct, run, and history match the reservoir simulation model.

The end points used by the Proponent to construct the relative permeability curves are shown in Table 3, while the pseudo-relative permeability curves generated during the history match for the Hibernia reservoir are shown in Figure 5.

Table 3: Scaling End Points for Normalized Pseudo-Relative Permeability Curves (Source: After HMDC 2002)

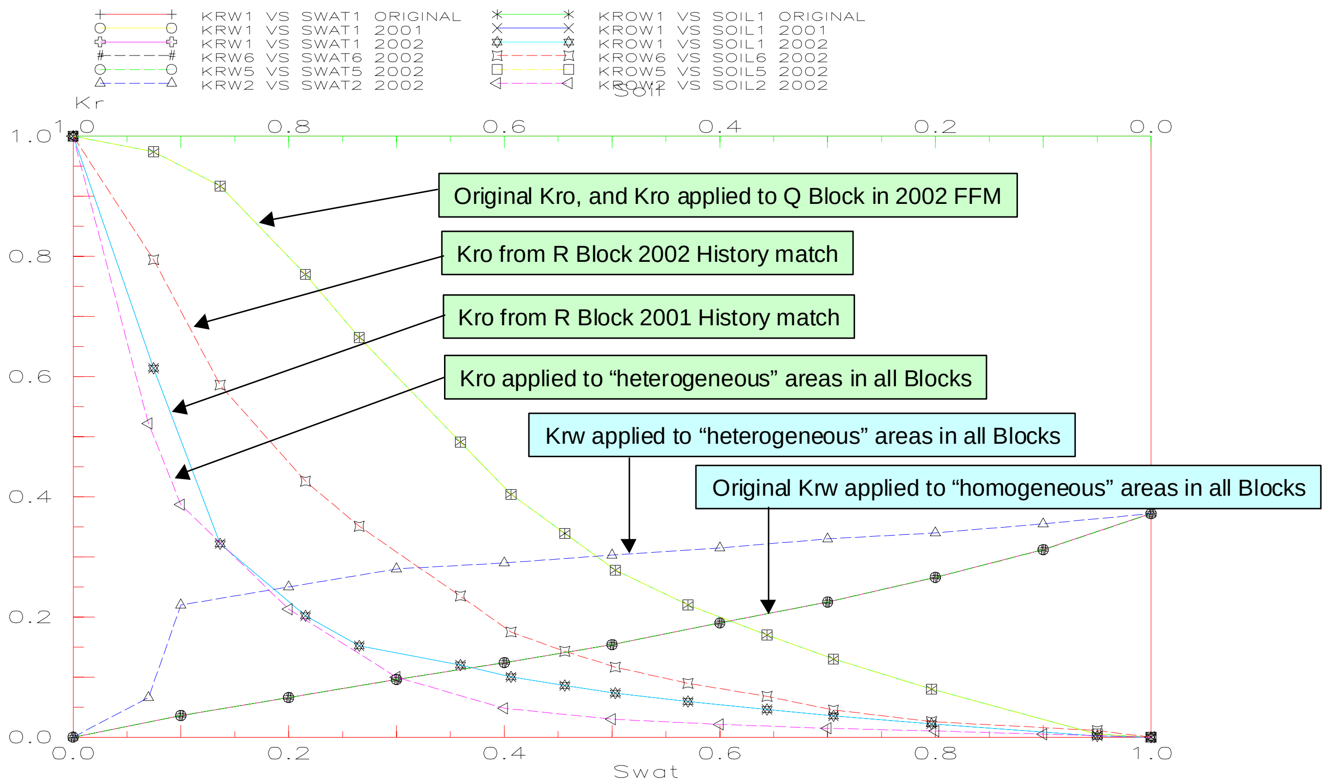
	Hibernia Reservoir	**BenNevis/Avalon Reservoir**
Connate Water Saturation, Swi	Input array based on transform applied as a function of porosity to the earth-model grid	
Residual Oil Saturation to Water flood	23.5%	29%
Critical Gas Saturation	5%	N/A
Residual Oil Saturation to Gas flood	15%	N/A

The following field and platform constraints were applied by the Proponent to the reservoir simulation model:

- Oil production limit Sensitivities run at 28 600 and 35 000 m^3/d
- Gas Production limit 8.0 million m^3/d
- Fuel gas usage 0.4 million m^3/d
- Flare target 0.1 million m^3/d
- Gas Injection limit 7.5 million m^3/d
- Water Injection limit 45 000 m^3/d
- Water handling limit None

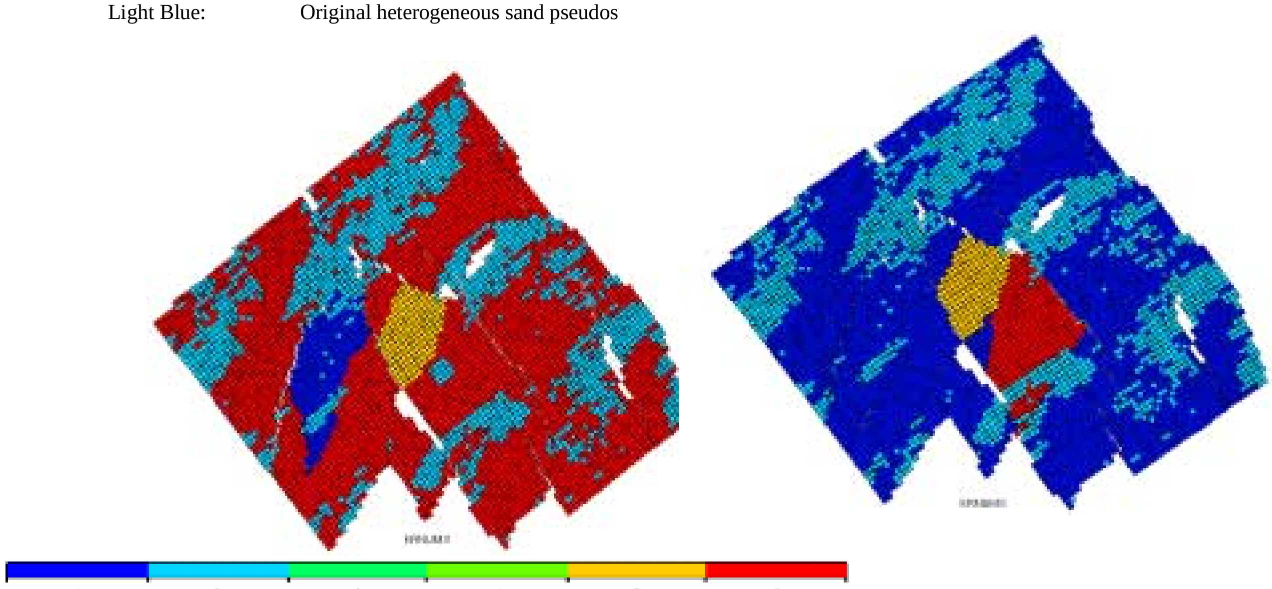
Figure 5: Hibernia Pseudo-Relative Permeability (Source: After HMDC 2002)

Unscaled Relative Permeability Curves Applied to FFM



Relative Permeability assigned by grid block in 2002 Hibernia reservoir model is shown on the left. Pseudos from R Block water cut match applied to all Blocks except Q, V and W. The picture on the right shows a sensitivity whereby the more aggressive 2001 R Block water cut match was applied to all Blocks except R, Q, V and W. The left hand case was adopted which gave a better match to current R Block and predicted slightly less aggressive water cut development

Key	Red:	R Block 2002 match
	Dark Blue:	R Block 2001 match
	Yellow:	original pseudos
	Light Blue:	Original heterogeneous sand pseudos



In addition, the Proponent imposed production and injection simulator controls and well and reservoir constraints for the water flood and gas flood. A summary of the water flood well constraints is shown in Table 4. The Proponent stated that, the production and injection rules closely model the way the gas flood wells are handled in reality and does a good job in replicating the water flood production prioritization when the field is gas constrained.

Table 4: Summary of Water Flood Well Constraints (Source: After HMDC 2002)

	Hibernia	**Ben Nevis/Avalon**
Producing well constraints		
Maximum oil rate (typical)	6400 m^3/d	2500 m^3/d
Minimum flowing BHP	Based on bubble point for the block	19 MPa (maximum drawdown 1.9 MPa)
Minimum flowing surface pressure	7.6 MPa	1.3 MPa
Water cut economic limit	90%	90%
Oil economic limit	200 m^3/d	100 m^3/d
Water Injection well constraints		
Maximum injecting BHP (typical)	46 MPa	40 MPa
Maximum injecting surface pressure (typical)	21 MPa	21 MPa
Water injection economic limit	500 m^3/d	250 m^3/d

Two production scenarios were developed for modeling purposes. The base scenario drilling schedule (Hibernia reservoir success with no further Ben Nevis/Avalon reservoir development) is shown in Figure 3, based on certain key assumptions.

- Gas flood performance is successful.
  - All stratigraphic units contribute except B5 Pool Zone 2, (Layer 3 Basal) in C, I, and H blocks, and B5 Pool Zone 1, (Layer 2) at the crest of B and C blocks.
  - Well oil production rate limit is 3 400 m^3/d.
- Initially perforate all zones in Hibernia water flood wells, shut-in flooded zones in producers.
- Water injection upgrade (December 2002) to 45 000 m^3/d.
- Ben Nevis/Avalon I block wells B-16 19Z and B-16 20Y, and Q block wells B-16 23 and B-16 32 opened in simulation layers 2 through 4 representing the B27 Upper and B27 Basal sands. No other Ben Nevis/Avalon wells are drilled or produced.
- Water injection into Ben Nevis/Avalon Q Block well B-16 32 limited to 1000 m^3/d based on current performance. Ben Nevis/Avalon oil rate constraint not applied explicitly. Upgrades have been identified that can sufficiently de-bottleneck the second stage compression capacity.
- No artificial lift.

The second scenario (limited Ben Nevis/Avalon reservoir development) retains the constraints noted for the base case and provides for limited development of the Ben Nevis/Avalon reservoir.

- In addition to the existing I and Q block wells, seven more producer/injector pairs are established.

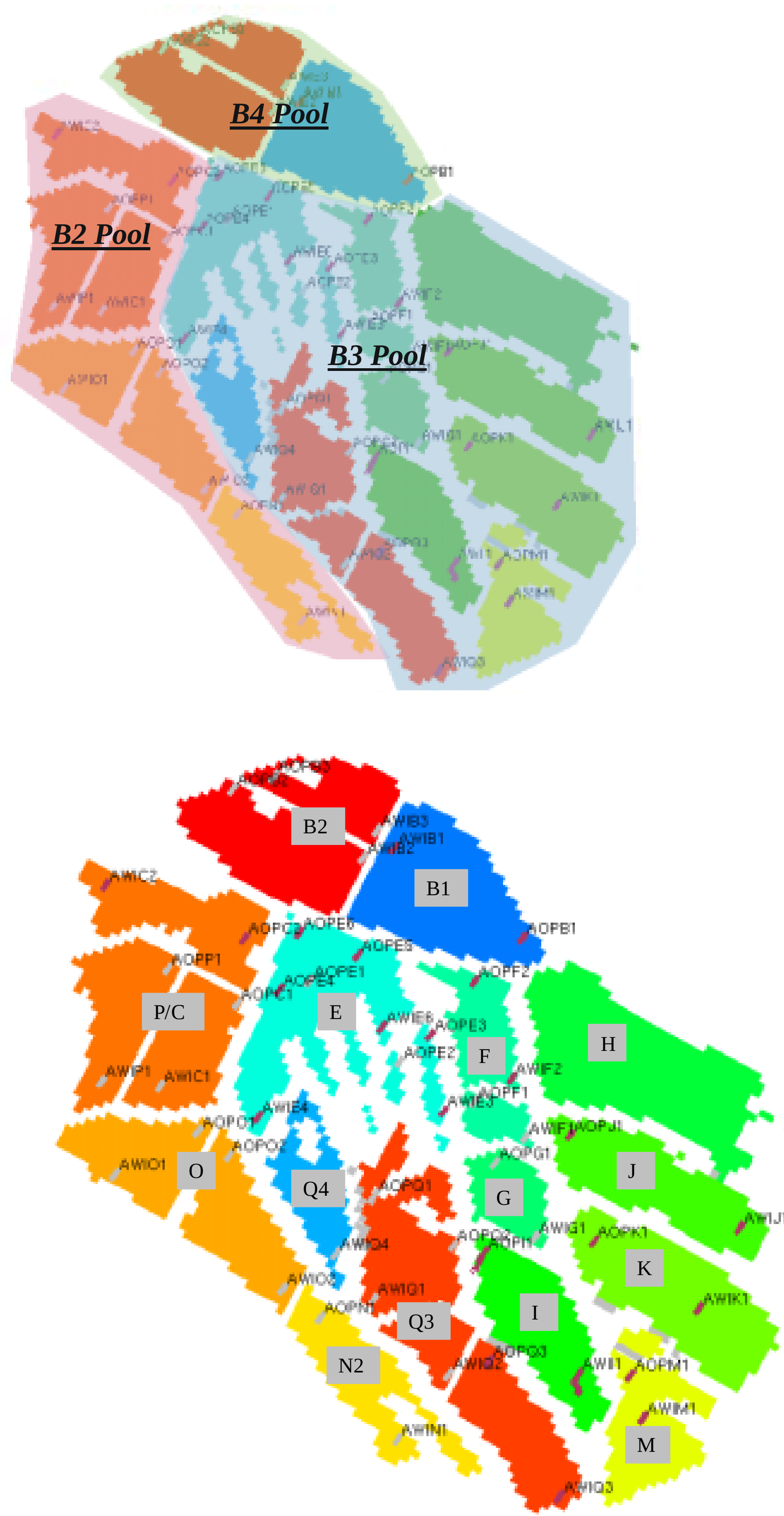
- 13 new Ben Nevis/Avalon wells drilled into fault blocks B1 (2 wells), K (1 water injector), N2 (2 wells), O (4 wells) and Q3/Q4 (4 wells), (see Figure 6 for the fault block designations). The drilling schedule for this scenario is presented in Figure 4.
- The wells in I, K, Q3/Q4 and N2 blocks are opened in simulation layers 2 through 4 representing the B27 Upper and B27 Basal sands.
- The wells in O block are opened in simulation layers 1 and 2 to represent the O35 sand.
- The wells in block B1 are opened in simulation layer 4 only to represent a thin B27 Basal sand.

The Proponent stated that the Ben Nevis/Avalon reservoir success scenario has been submitted previously in the document "***Technical Support for Hibernia Field Rate Increase*",** September 2002.

The Proponent noted further areas of future model enhancement.

- Uncertainty in Ben Nevis/Avalon reservoir model. Re-assessment of structure and stratigraphy is in progress, which will lead to a new Ben Nevis/Avalon reservoir model in 2003.
- Variance between simulation original oil-in-place and mapped volumetrics. Pore volume corrections have been applied by stratigraphic unit to be consistent with latest volumetrics. The structural interpretation and reservoir characterization date from late 2000, and corrections, have been applied where necessary to reflect recent well data. The 2002 (Hibernia reservoir) simulation model currently being developed will have better volumetric consistency.
- The tar mat encountered in the vicinity of the oil-water contact in the gas flood area has not been modeled. The 2002 (Hibernia reservoir) simulation model will include this feature. The tar mat will restrict hydrocarbons from migrating into the water leg and not modeling it represents a worse case. Thus, it does not detract from the fundamental results and conclusions of the rate sensitivity analysis.
- Prioritization of water injection when platform is water injection constrained. Water injection is allocated in proportion to water injection well potential, whereas in reality water would be diverted into low water cut blocks. This, in conjunction with a more judicious choice and timing of workovers than would occur in reality, will predict a more aggressive water production profile than is likely to occur.

Figure 6: Ben Nevis/Avalon Simulation Model Pool and Fault Block Designations (Source: After HMDC 2002)



Note:
The well locations shown in this figure are those used in the Ben-Nevis-Avalon "success" scenario, described in "Technical Support for Hibernia Field Rate Increase, September 2002". Only some of the wells were turned on in the cases investigated in this document.

The Proponent ran several sensitivities to the field and reservoir constraints using the simulation model with varying assumptions on reservoir performance. The Proponent noted the primary constraints affecting production are gas handling, water injection and drilling slot constraint. Further, to make most efficient use of the drilling rigs and develop new areas of the field, existing areas of the field must be depleted as quickly as economically feasible. According to the Proponent, maximizing oil production off-take, on the basis that there is no detriment to ultimate recovery as described in this document, is consistent with this strategy.

As a result of the simulation studies, the Proponent plans to evaluate potential initiatives.

(i) More detailed study of the Hibernia reservoir gas storage opportunities in particular the Q and R blocks.
- Timing- Q block provides the earliest opportunity for gas storage, whilst R block would provide the largest and most reliable gas storage capacity. O block gas storage potential may be able to “bridge the gap” between the timing of Q and R block gas floods.
- Accelerate completion of Q and R water floods.
- Optimization of producer/injector locations.
- Water bailer performance.
- Optimize use of gas storage- explore the inter-relationship between the gas flood and gas storage.

(ii) Detailed engineering analysis of increasing water injection above 45 000 m^3/d.
- Engineering study to resolve power supply, de-aerated water supply, deck space and auxiliary systems requirements (e.g. seawater lift, cooling medium).

(iii) Produced water handling upgrades.
- While current forecasts estimate water production will not exceed 14 000 m^3/d until 2004 or later, a project is currently underway to de-bottleneck the produced water handling system in order to achieve its design capacity of 28 000 m^3/d. This project is scheduled for completion by year end 2003.
- Expansion of the produced water system beyond 28 000 m^3/d may be required if water injection capacity is increased. As part of this project the feasibility of produced water re-injection will be assessed in accordance with the Offshore Waste Treatment Guidelines issued by the C-NOPB in August 2002.

(iv) Gas flood miscibility potential.
- Initial laboratory studies were completed in 2002 and the results are being reviewed to determine if further laboratory experiments are required.
- The laboratory results will be matched using an EOS-PVT (equation of state – pressure volume temperature) model, which will be used to conduct compositional modeling of the gas flood.

2.2.4 Prediction Cases: Descriptions and Results

The Proponent used the reservoir simulation model previously described to assess the impact of production rate on oil recovery. Three cases were examined with the model. Two cases, 28 600 m^3/d (180,000 b/d) and 35 000 m^3/d (220,000 b/d), were based on the Hibernia reservoir success and no further Ben Nevis/Avalon reservoir development scenario. The third case, 35 000 m^3/d (220,000 b/d), was run to show the impact of a limited Ben Nevis/Avalon reservoir development.

A comprehensive assessment of the results of each case, including estimated oil recovery for each fault block and each pool and zone within a fault block, was provided by the Proponent. A comparison of the cumulative recovery for the rate sensitivity cases is provided in Table 5 and Figure 7. The Proponent notes that the results are considered valid in terms of their comparative results but not necessarily in terms of the absolute recovery levels. It is the Proponent's view that it can be concluded from the results that the ultimate oil recovery is insensitive to field off-take rates from 28 600 m^3/d (180,000 b/d) up to at least 35 000 m^3/d (220,000 b/d).

The Proponent also presented the results, Figure 8, of its assessment of limited Ben Nevis/Avalon reservoir development and provided annual average field production forecasts for oil production rates of 35 000 m^3/d and 28 600 m^3/d. These are shown in Figures 9 and 10, respectively. These forecasts are based on 100% operating efficiency and well availability.

Table 5: Comparison of Cumulative Recovery for Rate Sensitivity Cases, "Hibernia Reservoir Success - No Further Ben Nevis/Avalon Development" Scenario (Source: After HMDC 2002)

Maximum Field Rate		28 600m³/d	35 000m³/d	28 600m³/d	35 000m³/d	28 600m³/d	35 000m³/d
Reservoir	Simulated STOOIP	Cum. Oil end 2015		Cum. Oil end 2017		Cum. Oil end 2025	
	1000m³	1000m³		1000m³		1000m³	
Hibernia Gas Flood	99,532	42,683	42,297	44,051	43,729	47,390	47,261
Hibernia Water Flood	145,523	67,800	68,563	68,705	69,102	69,890	69,988
Hibernia Reservoir	247,592	110,483	110,859	112,756	112,831	117,280	117,249
BNA Reservoir	276,450	6,508	6,508	6,700	6,700	6,841	6,839
Hibernia Field	521,728	116,991	117,367	119,457	119,531	124,121	124,089
Total Difference 1000m³			0.3% 376		0.1% 74		0.0% -32

Figure 7: Comparison of Field Production and Recovery for the Rate Sensitivity Cases - "Hibernia Success - No Further BNA" Scenario (Source: After HMDC 2002)

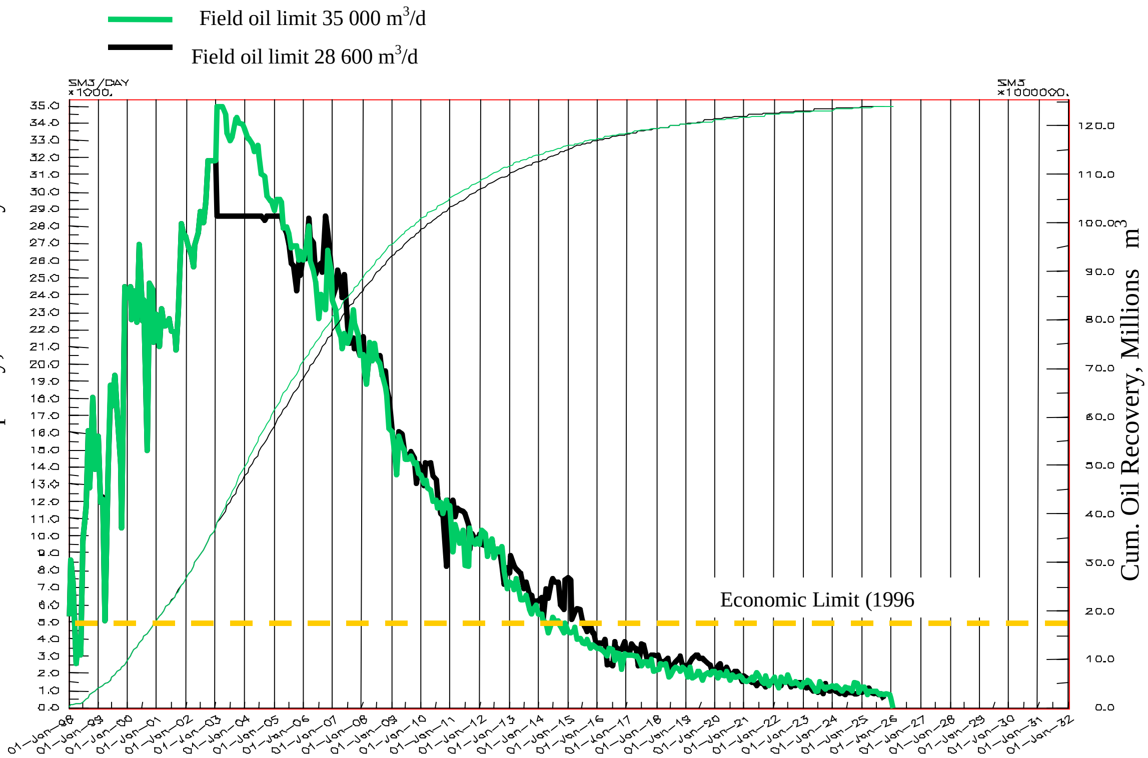


Figure 8: Impact of a Limited BNA Development on Field Production and Recovery Compared to No Further BNA Development, 35 000 m^3/d Field Production Limit (Source: After HMDC 2002)

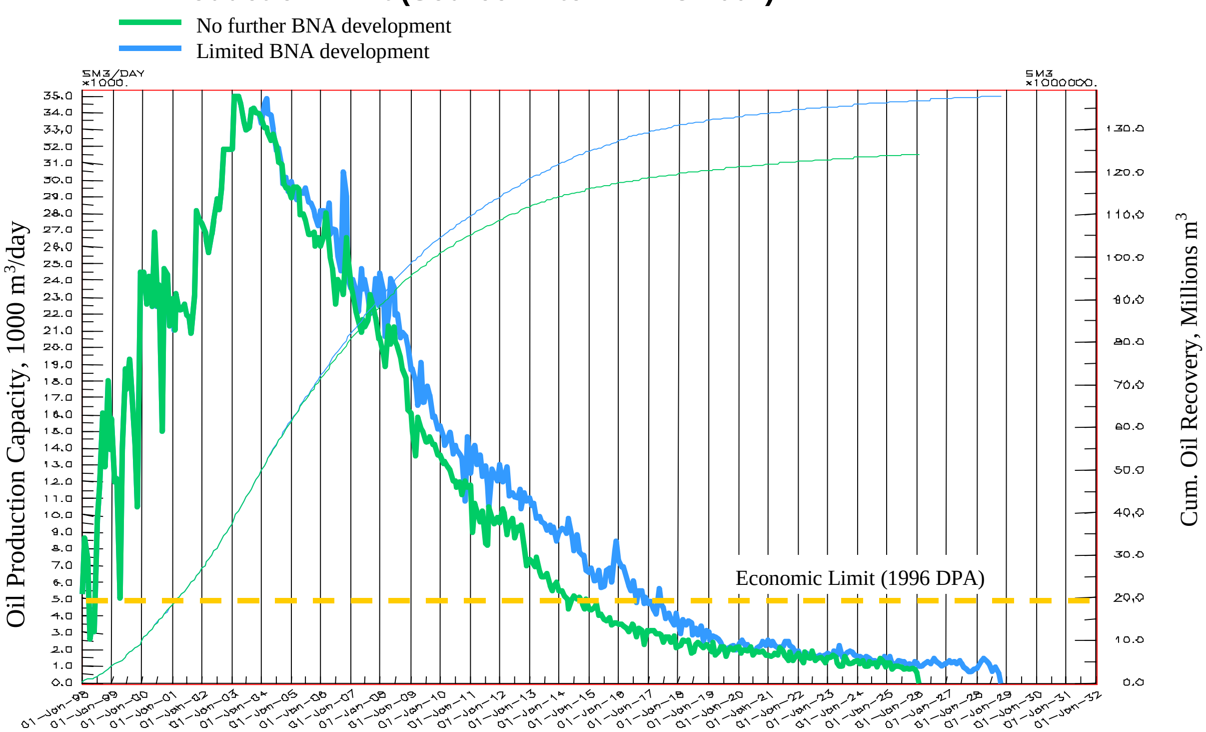


Figure 9: Annual Average Field Production Forecast 220,000 b/d (35 000 m³/d) Case, Metric Units (Source: After HMDC 2002)

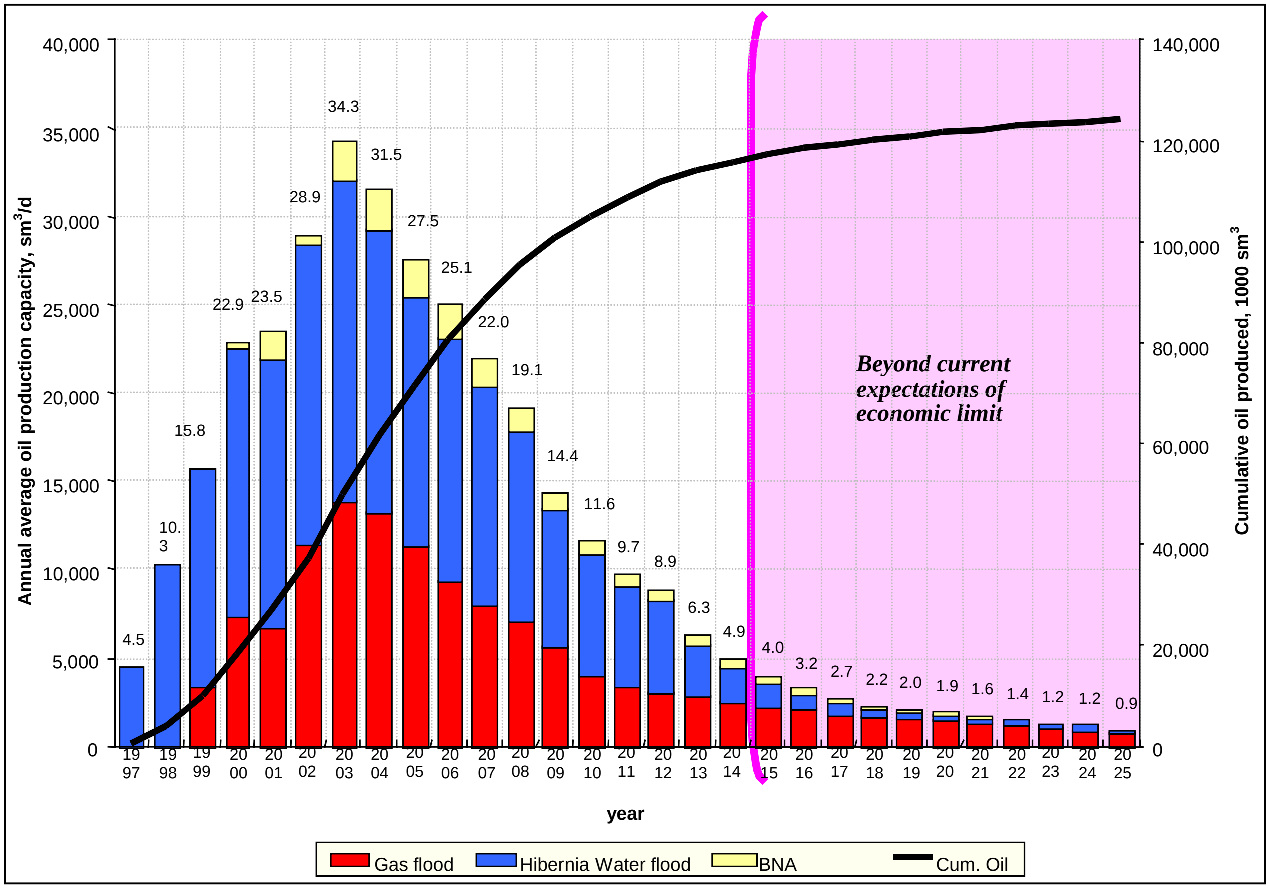
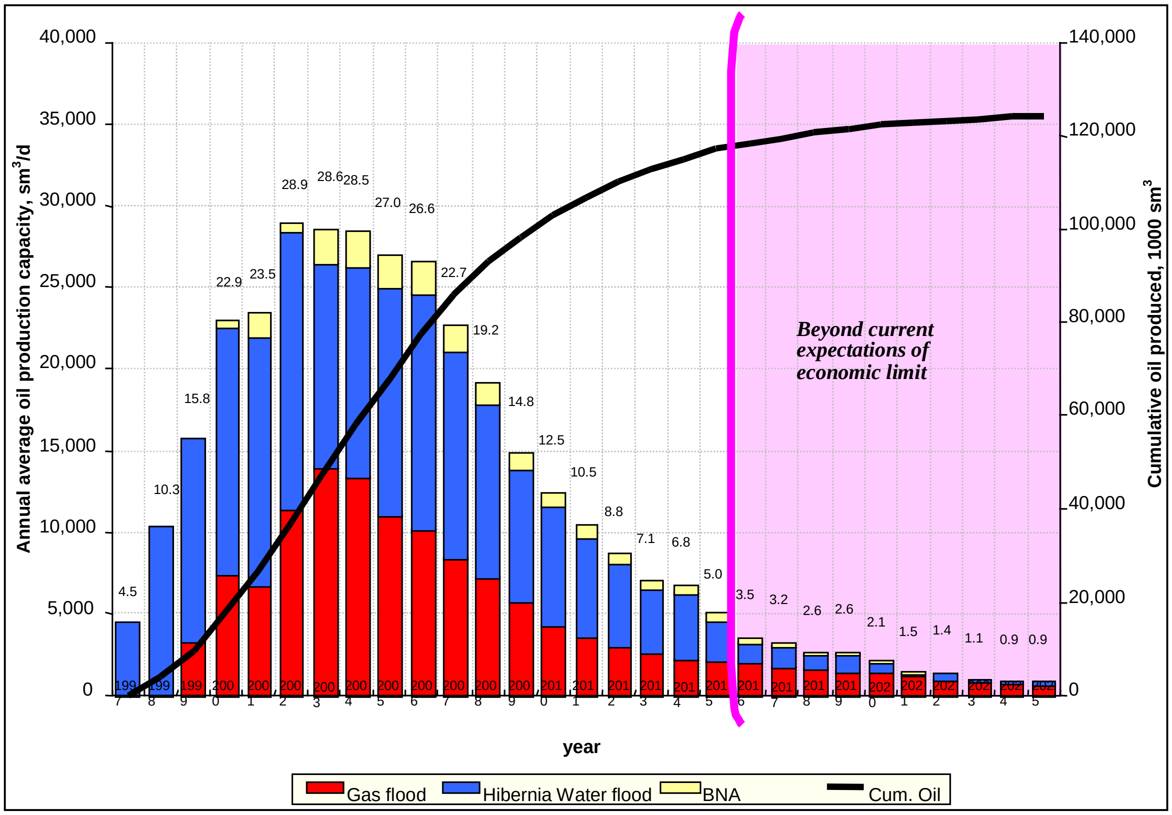


Figure 10: Annual Average Field Production Forecast 180,000 b/d (28 600 m³/d) Case, Metric Units (Source: After HMDC 2002)



3.0 C-NOPB Review

3.1 Background

Authority to determine production rates is addressed in the Newfoundland Offshore Area Petroleum Production and Conservation Regulations Part V Section 34. More specifically this section states that:

> ***An operator shall produce petroleum from a pool or field in accordance with good production practices to achieve maximum recovery of petroleum from the pool or field and at the applicable rate specified in the approved development plan for that pool or field.***

The applicable rate in the approved Hibernia Development Plan, including approved amendments, is the rate provided in the production forecast. This rate is based on the approved depletion scheme for a pool or field. The proposed rate increase is an amendment to Part 1 of the Hibernia Development Plan and is thereby a Fundamental Decision.

3.2 Resource Management Considerations

The reservoir simulation report submitted in support of the application to increase the annual oil production rate has been reviewed. Similarly the Proponent's reservoir simulation model and reservoir, geological and production data acquired to date were reviewed. The Hibernia field has been producing oil for more than five years. Up to December 31, 2002, about 37.3 million m^3 (235 million barrels) of oil has been produced. Thirty-three development wells and one delineation well have been drilled. A substantial quantity of data has been acquired to develop comprehensive geologic and reservoir simulation models in order to assess production performance in support of the rate increase application.

The information acquired from drilling and production operations has been used to construct a geologic model of the Hibernia reservoir and assess the original oil and gas-in-place. A comparison of the Board's and Proponent's oil-in-place and gas-in-place estimates is provided in Tables 6 and 7, respectively. In respect of the original oil-in-place estimates, while there are variations in the estimates on a fault block basis, there is generally good agreement between the Proponent and the Board's estimates. The Board's original gas-in-place estimate is about 20 percent higher than that carried by the Proponent. Significant differences were observed in the gas-in-place estimates on a fault block basis, particularly for the gas cap region. This was due in part to different boundaries used to define the fault blocks. Once this factor is reconciled there is fair agreement between the Board's and Proponent's estimates for the gas cap gas. In terms of the solution gas estimates, the higher estimates carried by the Board are attributed in part to the higher gas/oil ratio used by the Board: as an example for the B pools the Board used an average gas/oil ratio of 235 m^3/m^3 compared to Proponent's 211 m^3/m^3. These factors do not have any significant impact on the rate application presented by the Proponent.

The data and assumptions used by the Proponent to construct the reservoir simulation model were analyzed. This analysis has concluded that their assumptions are reasonable. It is noted that the Proponent has conducted a comprehensive assessment of drilling slots utilization. With the limited number of drilling slots available on the Hibernia platform and priority on depletion of the Hibernia reservoir, it is clear that the pace of development of the Ben Nevis/Avalon reservoir is affected by the availability of well slots. The Proponent assumed no artificial lift for the reservoir simulation model. The performance of the Hibernia reservoir to date indicates that the producing wells can flow naturally at high water cuts. However, in discussions with the Proponent on this matter, the Proponent stated that artificial lift was planned for Ben Nevis/Avalon producing wells. While the Proponent's simulation model has not provided for the "tar mat" encountered in the gas flood area, the Board's analysis concurs with the Proponent's view that not including the "tar mat", does not detract from the fundamental results and conclusions of the rate sensitivity analysis. The Proponent has conducted a comprehensive assessment of the production, geological and geophysical data to construct the reservoir simulation model and achieved a good history match of the pressure and production data acquired from the development wells. Many assumptions have been made both in constructing the model and with respect to the approach used to exploit the oil reserves. The effectiveness of the depletion scheme and validity of the assumptions will be monitored. If necessary, the Proponent will be required to make changes to achieve maximum economic oil recovery.

A detailed review of the Proponent's reservoir simulation was conducted. As the reservoir simulation model prediction is initiated on January 1, 2002, the predicted performance of the simulator for selected wells was checked against the actual performance. This data suggests that, in general, the performance during 2002 has been better than predicted in terms of water and gas breakthrough. A review of the oil saturation predictions noted several areas in the Hibernia reservoir C fault block and O fault block that will not be depleted and offer potential infill drilling opportunities. Collectively, at the end of the simulation prediction period, these areas are estimated to contain about 19.8 million m^3 (125 million barrels) of oil-in-place. Substantive technical and economic analyses must be undertaken before proceeding with any infill drilling program. This is typical of opportunities that the Proponent is expected to pursue to sustain production. Based on the production performance to date, it has been concluded that the Hibernia reservoir oil recovery is not rate sensitive at the proposed rates. However, there could be rate sensitivity in some Hibernia reservoir fault blocks under certain conditions, particularly in the gas flood area. Production performance will be monitored to identify any concerns and well or fault block rate restraints will be imposed as may be necessary.

The Proponent's simulation studies provide for depletion of the majority of the B pool fault blocks in the Hibernia reservoir and a selected area of the Ben Nevis/Avalon reservoir. The reservoir simulation studies do not specifically account for depletion of the oil and natural gas liquids in the following areas:

- the Hibernia A pools which are estimated to contain about 18.9 million m^3 (119 million barrels) of original oil-in-place and which have not yet been approved for development;
- the Ben Nevis/Avalon reservoir, excepting appraisal development;
- the Catalina and several smaller reservoirs; and,

- the natural gas liquids associated with the Hibernia reservoir gas cap.

It is likely that some of these hydrocarbon resources will be exploited in the future. Such development could increase production rates and extend producing life.

Other factors may present a challenge to achieving the requested production rate. These factors include drilling problems which could lead to development wells not being available in a timely manner, reduced well productivity or injectivity caused by unexpected reservoir conditions or problems encountered during completion or operation of the wells, and unexpected problems with components of the production system. These are typical challenges faced by all developments.

The Proponent has already made minor modifications to the water injection facilities to increase the water injection capacity from 33 000 m^3/d to 45 000 m^3/d and the Proponent's plans to assess gas storage opportunities are acknowledged. Potential gas storage locations have been discussed with the Proponent.

The Proponent plans to evaluate several potential initiatives including gas storage opportunities, increasing water injection above 45 000 m^3/d (283,000 b/d), produced water handling upgrades and gas flood miscibility potential. The Board accepts as part of this Decision Report that the depletion scheme now provides for possible increased injection or produced water volumes, conversion of certain water flood fault blocks to gas flood or gas storage and that it similarly allows for possible miscibility in gas flood blocks. If the Proponent elects to pursue any of these initiatives appropriate approvals must be first issued by the Board. However, if the initiative involves substantial modification or additions to existing production facilities, this will constitute an amendment to the Development Plan and as such will be a Fundamental Decision.

The Proponent's plan to evaluate gas flood miscibility potential has been noted. This is an outstanding condition from Decision 86.01. Given the maturity of the Hibernia reservoir development and the data collected to date, this issue should be expeditiously addressed in a timely manner. The Board will pursue this issue with the Proponent.

3.3 Impact on Life of Field

Predicting the impact of up to a 6 360 m^3/d (40,000 b/d) increase on the ultimate producing life of a large offshore field such as Hibernia is a very inexact science. If all other factors remain equal throughout the field life (which we know will not be the case), the higher rate of production could reduce field life up to a year.

It is important at this time to recognize however that the single biggest unknown factor in determining the life of the Hibernia field is the extent of ultimate recovery from the Ben Nevis/Avalon reservoir. Recovery from Ben Nevis/Avalon at conventional rates could add up to an additional 5 years or more to field life. As indicated previously in this report, the Proponent has requested a three-year extension for the submission of the Ben Nevis/Avalon

Development Plan to December 2005. The Board's Decision on this request will be the subject of a further Fundamental Decision in the coming months.

The Board also notes other factors which have the potential to impact field life include improved technology, oil prices or operating costs, infill drilling, satellite pool developments, and future gas development.

The Proponent's economic limit is presented in Figures 7 thru 10. Given the number of variables that must be considered and the inability to accurately project oil prices and other economic factors over the long term, any economic limit projection must be viewed cautiously.

3.4 Environmental Considerations

The increased production rates proposed by the Proponent may be associated with earlier water production at daily rates greater than the maximum currently approved by the Board. The treatment and disposition of produced water is described in the Environmental Protection Plan component of the *Hibernia Operational Plan*. Any substantive change in these arrangements requires the approval of the Board's Chief Conservation Officer pursuant to the *Newfoundland Offshore Area Petroleum Production and Conservation Regulations*.

The August 2002 Offshore Waste Treatment Guidelines state (Section 2.3, Produced Water, Page 4) that

> **Each operator of a production installation should, as part of its development application, examine and report upon the technical and economic feasibility of alternatives to conventional marine discharge of produced water (e.g., subsurface re-injection, subsea separation, downhole separation), to justify a marine discharge. Operators of existing production installations should re-examine this feasibility every five years and report thereon to the Chief Conservation Officer.**

In view of the above and given that the Hibernia field has been on production for more than 5 years, the feasibility study required by the guidelines should be undertaken immediately. If this feasibility study indicates that the re-injection of some or all of the produced water associated with the Project is feasible, it should be possible to reduce marine disposal of produced water or in any event continue at less than the maximum currently approved. The Board does not intend to consider an application for marine discharge of larger volumes of produced water without first having received and reviewed a report on such an analysis.

In the event re-injection of produced water should prove unfeasible, the potential environmental effects of produced water discharges greater than those already approved must be thoroughly assessed prior to any application being considered. The information associated with these assessments and reports should be available for review by interested parties in government and the general public.

The proposed production increase also will result in a proportional increase in the discharge of storage displacement water (SDW) from the platform. SDW is seawater that is pumped into the crude oil storage cells in the GBS caisson when oil is discharged to a shuttle tanker, so that the cells remain filled with fluid. The SDW then is discharged from the cells as oil is produced into them. The volume of SDW discharged therefore is approximately equal to that of crude oil produced.

The August 2002 *Offshore Waste Treatment Guidelines* currently require that SDW to be treated so that its oil concentration does not exceed 15 mg/l. Hibernia has consistently met this requirement; its average SDW oil-in-water concentration in 2002 was less than 2 mg/l.

Notwithstanding the performance of treatment to date, the Board, in consideration of the large volume of this discharge, encourages the proponent to closely evaluate the results of its approved Environmental Effects Monitoring program to ensure that storage displacement water does not cause, nor contribute to, unanticipated environmental effects.

3.5 Safety

The Board's Chief Safety Officer has also considered how higher rates might affect the safety of operations and has concluded that the equipment and procedures in place can safely handle the higher rates.

Table 6 Comparison of Original Oil in Place Estimates Million m^3 (Million Barrels)

Pool	Fault Block	Original Oil in Place Estimates A Pool Proponent	A Pool C-NOPB	B Pool Proponent	B Pool C-NOPB	Total Proponent	Total C-NOPB
A6/B6	A (+E)	0.354	2.145	26.781	21.440	27.135	22.078
A5/B5	B	0.417	0.894	12.899	9.910	13.316	10.632
	C	3.190	1.295	21.503	27.610	24.693	28.980
	D	0.035	0.000	5.137	1.290	5.172	1.290
	F	0.178	0.045	3.306	1.530	3.484	1.642
	G	0.216	2.172	15.584	12.430	15.800	13.264
	H	0.291	0.193	3.209	3.630	3.500	3.896
	I	0.528	0.700	5.027	4.980	5.555	5.560
	J	0.958	1.346	1.463	3.210	2.421	5.070
	K	0.880	0.902	5.901	6.110	6.781	7.830
	L	0.017	0.282	2.672	3.740	2.689	4.293
	M	0.181	0.000	1.328	1.670	1.509	1.955
	N	0.000	0.000	0.601	0.180	0.601	0.180
A1/B1	O	4.082	4.736	9.981	14.660	14.063	15.980
A4/B4	P	0.001	0.026	2.382	2.570	2.383	2.636
	Q	0.000	0.000	11.356	10.810	11.356	10.810
	R	0.630	3.892	31.583	34.950	32.213	38.660
	S	0.115	0.234	2.989	3.440	3.104	3.504
	EE	0.169	0.542	1.514	0.960	1.683	1.365
	FF	0.750	1.238	4.669	5.550	5.419	6.056
A3/B3	T	0.395	0.564	2.078	1.710	2.473	2.303
	V	1.706	1.412	10.678	9.350	12.384	11.360
A2/B2	W	1.402	1.834	23.577	20.010	24.979	21.830
	X	0.286	0.568	4.486	4.530	4.772	5.067
	Y	0.397	0.693	5.723	4.740	6.120	5.730
	Z	0.213	0.363	0.993	0.830	1.206	1.564
	AA	0.019	0.000	0.000	0.000	0.019	0.116
	BB	0.686	0.494	3.638	2.340	4.324	3.350
	CC	0.711	0.948	11.607	10.020	12.318	12.000
	DD	0.051	0.298	3.136	1.240	3.187	1.744
	GG	0.000	0.000	0.301	0.000	0.301	0.000
Total Hibernia Reservoir		**18.858**	**27.816**	**236.102**	**225.440**	**254.960**	**253.256**
		(118.6)	**(175.0)**	**(1485.0)**	**(1418.0)**	**(1603.7)**	**(1593.7)**

Table 7 Comparison of Original Gas-in-Place Estimates Millions m^3 (Billions Standard Cubic Feet)

		Gas Cap, Gas in Place				Solution Gas					
		A Pool		B Pool		A Pool		B Pool		Total	
Pool	Fault Block	Proponent	C-NOPB	Proponent	C-NOPB	Proponent	C-NOPB	Proponent	C-NOPB	Proponent	C-NOPB
A6/B6	**A (+E)**	495	676	2894	3590	82	450	6363	5253	9835	9969
											0
A5/B5	**B**	141	153	462	281	97	188	2951	2427	3651	3049
	C	1276	942	1681	2769	775	272	4920	6764	8652	10747
	D	32	141	1255	480	11	0	1175	315	2473	936
	F	112	347	627	1781	60	13	786	374	1585	2515
	G	109	547	936	2683	50	465	3565	6046	4660	9741
	H	23	23	18	86	76	41	734	889	851	1039
	I	66	52	51	117	141	147	1150	1221	1408	1537
	J	0		0	0	196	283	335	707	531	990
	K	2		0	0	193	190	1350	1345	1545	1535
	L	0	120	111	17	60	80	588	1113	759	1330
	M	0		16	0	47	0	292	498	355	498
	N	2	31	1983	96	0	0	159	55	2144	182
											0
A1/B1	**O**	0		0	0	1041	1123	1951	3504	2992	4627
											0
A4/B4	**P**	217	265	1414	1644	0	8	671	766	2302	2683
	Q	780	1266	4105	5351	0	0	3198	3221	8083	9838
	R	35	395	19	2	125	833	6392	7480	6571	8710
	S	14	111	0	0	25	50	605	736	644	897
	EE	0		0	0	34	144	227	159	261	303
	FF	112		0	0	149	329	699	921	960	1250
											0
A3/B3	**T**	0		0	0	88	134	420	399	508	533
	V	0		0	0	458	376	2161	2236	2619	2612
											0
A2/B2	**W**	0		0	0	404	488	4335	5084	4739	5572
	X	0		0	0	79	151	1007	1059	1086	1210
	Y	0		0	0	94	184	1284	1110	1378	1294
	Z	0		0	0	40	96	173	193	213	289
	AA	0		0	0	1	0	0	0	1	0
	BB	0		0	0	148	131	448	594	596	725
	CC	0		0	0	142	252	1430	2344	1572	2596
	DD	0		0	0	9	79	386	265	395	344
	GG	0		0	0	0		37		37	0
Total Hibernia Reservoir		3416	5069	15572	18897	4625	6507	49794	57078	73405	87551
		(121.2)	(179.9)	(552.7)	(670.7)	(164.2)	(231)	(1767.3)	(2025.9)	(2605.4)	(3107.5)

4.0 Conclusion

Hibernia Development Plan Amendment
Decision 2003.01

The Board approves the Proponent's Application to increase the annual oil production rate to 35 000 m^3/d (220,000 b/d) subject to conditions 2003.01.01, 2003.01.02 and 2003.01.03, set out below, and the conditions contained in its Decision Reports 86.01, 90.01 and 97.01 and 2000.01. The outstanding conditions are summarized in Appendix A.

Under this approval, the maximum allowable annual oil production for the calendar year 2003 will be determined using the following daily average oil rates:

a) 28 600 m^3/d (180,000 b/d) from January 1, 2003 to the day immediately preceding the day upon which the Board's approval for an increase to the annual oil production rate becomes effective pursuant to Section 32 of the Acts; and,

b) 35 000 m^3/d (220,000 b/d) from the date that the Board's approval for an increase to that rate becomes effective pursuant to Section 32 of the Acts.

For each calendar year thereafter, the annual maximum allowable rate shall be the rate approved in (b) above.

Condition 2003.01.01
It is a condition of the Board's approval that:

> The Board's Chief Conservation Officer may at any time reduce the production rate if reservoir performance differs significantly from that predicted in the document entitled ***"Technical Support For Hibernia Field Rate Increase Revision 1",*** and the Chief Conservation Officer has reason to believe that production at the approved rate may cause waste.

Condition 2003.01.02
It is a condition of the Board's approval that:

(i) The Proponent undertake and submit to the Chief Conservation Officer no later than March 31, 2004 an analysis of the feasibility of produced water re-injection; and

(ii) The Proponent proceed with produced water re-injection if, in the opinion of the Chief Conservation Officer, it is technically feasible and economically reasonable to do so.

Condition 2003.01.03
It is a condition of the Board's approval that:

> No later than 6 months prior to seeking approval for anticipated marine discharge of produced water at a daily rate in excess of 24 000 m^3, the Proponent shall:
>
> (i) Submit, in a form suitable for public release and acceptable to the Board's Chief Conservation Officer, an assessment of the environmental effects of produced water discharge at the maximum daily discharge rate for which it anticipates seeking approval, including but not limited to:
> - A description of results from modeling of the physical fate of discharged produced water at rates up to the maximum daily rate proposed;
> - An assessment of the potential environmental effects of the aforementioned produced water; and
> - An assessment of any resultant changes to the conclusions of the *Hibernia Environmental Impact Statement*; and
>
> (ii) Submit for the approval of the Chief Conservation Officer revisions to the Environmental Protection Plan components of the *Hibernia Operational Plan* that are necessary in consideration of the assessment described in Condition 2003.01.03(i).

Appendix A

Outstanding Conditions From

Decisions 2000.01, 97.01, 90.01 and 86.01

A1
Hibernia Development Plan Amendment
Decision 2000.01

The Board has reviewed the status of its condition attached to its 2000 approval of the Hibernia Development Plan Amendment. This condition requires a continuing response.

Condition 2000.01.1

It is a condition of the Board's approval that:

This approval may be suspended or revoked if the Board's Chief Conservation Officer determines that the Proponent's operations depart significantly from those projected in the Application or if reservoir performance differs significantly from that predicted in its document entitled "*Technical Support for Hibernia Field Rate Increase*".

Status:

Condition 2000.01.1: Ongoing.

A2
Hibernia Development Plan Amendment
Decision 97.01

The Board has reviewed the status of the five conditions attached to its 1997 approval of the Hibernia Development Plan Amendment. One of these conditions has been fully satisfied. The remaining four conditions, some of which require a continuing response and some of which relate to activities that have yet to occur, have not yet been fully satisfied.

Condition 97.01.1

It is a condition of approval of the Amendment that:

(i) Prior to initiating of production from the Hibernia 'A' pools, the Proponent submit its depletion plan therefor for the approval of the Board.
(ii) The Development Plan update to be submitted following the appraisal period must provide a firm plan for delineation of the northwest and southwest areas of the Avalon reservoir.

Status:

Condition 97.01.1(i): Continued.

Condition 97.01.1(ii): Continued. The Proponent drilled a delineation well in the southwest of the Avalon reservoir during 2002. In December, 2002 the Proponent submitted an application for extension of the Avalon appraisal period to December 31, 2005. This request was under consideration by the Board at the time this decision report was being prepared.

Condition 97.01.2

It is a condition of approval of the Amendment that:

(i) Prior to proceeding with the water flood in the Hibernia reservoir ‘B5’ pool ‘H’ and ‘I’ fault blocks the Proponent reassess the depletion schemes for these blocks and obtain the approval of the Chief Conservation Officer for the scheme to be implemented.
(ii) The oil production rate in the Hibernia reservoir ‘G’ gas flood block is restricted to a maximum rate of 1190 STm^3/d per well until such time it can be demonstrated to the Chief Conservation Officer that a higher production rate will not be detrimental to oil recovery.
(iii) The reservoir pressure in those fault blocks containing a gas cap shall be maintained at least 1000 kPa above the dew point pressure. In other fault blocks, the reservoir pressure shall be maintained at least 500 kPa above the bubble point pressure.

Status:

Condition 97.01.2(i): Satisfied.

Condition 97.01.2(ii): Satisfied.

Condition 97.01.2(iii): Ongoing.

Condition 97.01.3

It is a condition of approval of the Amendment that:

(i) The proponent shall submit annually for the information of the Chief Conservation Officer a forecast of oil production from each pool for the coming year.
(ii) One year following the commencement of gas injection, the proponent shall submit a revised forecast of the natural gas liquids production.

Status:

Condition 97.01.3(i): Satisfied.

Condition 97.01.3(ii): Satisfied.

Condition 97.01.4

It is a condition of approval of the Amendment that before the end of 1999 the Proponent submit a report detailing the revised Hibernia Field reserve estimates. The report is to present the range of oil and natural gas liquids reserves, downside, most likely and upside, anticipated for each pool and reservoir and is to include an explanation of the uncertainties involved and economic cut-off used to generate the estimates.

Status:

Condition 97.01.4: Satisfied.

Condition 97.01.5

It is a condition of approval of the Hibernia Development Plan Amendment that the Proponent evaluate the potential to exploit areas of the Avalon reservoir penetrated by Hibernia reservoir development wells and not proposed for development by re-completing selected wells. The results of the evaluation are to be presented in the Development Plan Update to be submitted to the Board following the Avalon reservoir appraisal period.

Status:

Condition 97.01.5(i): Ongoing. In December, 2002 the Proponent submitted an application for extension of the Avalon appraisal period to December 31,2005. This request was under consideration by the Board at the time this decision report was being prepared.

A3
Hibernia Development Plan Update
Decision 90.01

The Board attached four Conditions to its 1990 approval of the Hibernia Development Plan Update. These have all been satisfied.

A4
Hibernia Benefits Plan
Decision 86.01 Status

The Board attached five conditions to its 1986 approval of the Hibernia Benefits Plan. The following conditions have not been satisfied:

Condition #4

That as the project evolves, the Proponent provide to the Board comprehensive listings of all major contracts and purchase orders anticipated. The Board, in consultation with the Proponent, will determine which of these major contracts and purchase orders will be subject to Board review.

Status:

Satisfied/Ongoing.

The Proponent provides this information to the Board in accordance with the C-NOPB's *Procurement Reporting Guidelines*: Hibernia Development Project.

Condition #5

That the Proponent provide advance notice of and information on major contracts and purchase orders to enable the Board to conduct its review. The review time required will be determined by the Board, in full consultation with the Proponent.

Status:

Satisfied/Ongoing.

The Proponent provides this information to the Board, in accordance with the C-NOPB *Procurement Reporting Guidelines*: Hibernia Development Project.

A4
Hibernia Development Plan
Decision 86.01 Status

The Board attached seventeen conditions to its 1986 approval of the Hibernia Development Plan. The following conditions have not been satisfied:

Condition #1

(i) That the Proponent at a very early stage in the development program, drill a well in the area of the B-08 gas cap, to obtain samples for laboratory analyses and define a gas-condensate-oil regime; and,
(ii) that the Proponent undertake studies, concurrent with initial development drilling, to establish the feasibility of a miscible flood for the Hibernia reservoir.

Status:

The Proponent has undertaken to drill a well in the area of the B-08 gas cap early in the development and complete a miscible flood feasibility study.

Condition 1(i): Satisfied.
Condition 1(ii): Continued.

Condition #2

(i) That prior to any development of the Avalon Reservoir, the Proponent submit a revised plan for the Board's approval;
(ii) that during development of the Hibernia Reservoir, the Proponent evaluate the Avalon Reservoir by coring, logging and testing all prospective zones penetrated by wells drilled to the Hibernia Reservoir; and,
(iii) that during the design of topside facilities, the Proponent give due consideration to sizing equipment and allocating space for production facilities and utilities, sufficient to accommodate additional production from the Avalon Reservoir concurrently with Hibernia production, should there be a requirement to produce the Avalon Reservoir prior to the time contemplated in the Development Plan, and that the Proponent report to the Board on its actions in this regard before the topside facilities design is finalized.

Status:

Condition 2(i): Satisfied.

The submission of the 1996 Hibernia Development Plan Amendment constitutes a revised plan for development of the Avalon reservoir.

Condition 2(ii): Continued.

Condition 2(iii): Satisfied.

In August 1991, the Board accepted the Proponent's plans for satisfying this condition.

Condition #3

(i) That the Proponent file for approval by the Board, prior to commencement of development drilling, a specific drilling schedule designed to reduce gas flaring to limits acceptable to the Board;
(ii) that in the unlikely event that reservoir conditions prevent gas-reinjection, the Proponent present to the Board for approval a plan for gas disposal; and,
(iii) that the Proponent obtain the Board's approval to flare those small volumes of gas needed for normal operations.

Status:

Conditions 3(i) and 3(iii): Satisfied.

In August 1996, the Board conditionally approved the Proponent's drilling schedule and volumes of gas to be flared during start-up and transition to steady state operations.

Condition 3(ii): Continued.

The Proponent has informed the Board that it has evaluated the feasibility of gas re-injection, and considers it to be highly feasible. A plan for gas disposal will be necessary only if gas re-injection proves to be detrimental to the resource recovery.

Condition #5

(i) That the Proponent design the export lines and loading platforms so that they can be flushed of hydrocarbons if there is risk of damage to those facilities; and,
(ii) that the design iceberg scour depth be determined by the Proponent and approved by the Board prior to the design of subsea well installations.

Status:

Condition 5(i): Satisfied.

The Proponent designed its facilities so that export lines will be capable of being flushed, and, in a May 1997 submission to the Board, described its proposed procedures for flushing the risers in the offshore loading system. The Board approved the proposed procedures in May 1997.

Condition 5(ii): Continued.

No subsea well installations have yet been proposed.

Condition #9

That the Proponent obtain specific approval from the Board for its plans for subsea installations prior to proceeding with the detailed design of these facilities.

Status:

Continued.

Condition #15

That the Proponent provide periodically to the Board, during the execution of the project, in a form to be prescribed, estimates of the expected capital cost for the project as a whole and for those major components which the Board shall request.

Status:

Satisfied/Ongoing.

On a semi-annual basis, the Proponent's Canada-Newfoundland Benefits Department provides capital cost expenditure forecasts and associated estimates of Canada-Newfoundland content levels which are expected to be achieved.

Appendix B

Glossary

Aquifer
A porous rock that is water bearing.

Board, the
In this report, the Canada-Newfoundland Offshore Petroleum Board.

Bubble point pressure
The reservoir pressure below which dissolved gas begins to bubble out of the host oil at the prevailing temperature conditions.

C-NOPB
Canada-Newfoundland Offshore Petroleum Board

Certifying Authorities
Bodies licensed by the Board to conduct examination of designs, plans and facilities and to issue Certificates of Fitness.

Certificate of Fitness
A certificate issued by a certifying authority stating that a design, plan or facility complies with the relevant regulations or requirements.

Commingled production
Production of petroleum from more than one pool through a common wellbore or flow line without separate measurement of petroleum.

Completion
The activities necessary to prepare a well for the production of oil and gas or injection of a fluid.

Delineation well
Well drilled to determine the extent of a reservoir.

Development well
Well drilled for the purpose of production or observation or for the injection or disposal of fluid into or from a petroleum accumulation.

Dew point pressure
The reservoir pressure below which liquids begin to condense out of a gas at the prevailing temperature conditions.

Enriched gas injection
A secondary recovery method for injecting gas which is either naturally rich in or is enriched with intermediate hydrocarbons such as propane, butane.

Fault
In the geological sense, a break in the continuity of rock types.

Flare
To burn off gases not otherwise required.

Flooding
The injection of water or gas into or adjacent to, a productive formation or reservoir to increase oil recovery.

Gas cap

The layer of free gas above the oil zone of a reservoir.

Gas re-injection
Process where gas is re-cycled by being returned under pressure to a producing formation in order to maintain reservoir pressure.

GBS
Gravity Base Structure. The concrete production structure fixed to the sea floor by its own weight and which supports the topsides facilities.

Injection
The process of pumping gas or water into an oil-producing reservoir to provide a driving mechanism for increased oil production.

Logging
A systematic recording of data from the driller's log, mud log, electrical well log, or radioactivity log.

Miscible flood
A secondary or tertiary oil recovery method wherein two or more injection fluids are used, one behind the other, for example, gas and water, to mix with the oil and improve oil recovery characteristics.

NGL
Natural Gas Liquid.

OOIP
Original oil in place. Petrel Trademark of Schlumberger product group geologic modeling software.

Petrophysics
Study of reservoir properties from various logging methods.

Pool
Is a natural underground reservoir containing or appearing to contain an accumulation of petroleum that is separated or appears to be separated from any such other accumulation

Produced water
Water associated with oil and gas reservoirs that is produced along with the oil and gas.

Production platform
An offshore structure equipped to produce and process oil and gas.

Production well
A well drilled and completed for the purpose of producing crude oil or natural gas.

Recoverable reserves
That part of the hydrocarbon volumes in a reservoir that can be economically produced.

Reservoir
A porous, permeable rock formation in which hydrocarbons have accumulated.

Reservoir pressure
The pressure of fluids in a reservoir.

Sandstone
A compacted sedimentary rock composed of detrital grains of sand size.

Seismic

Pertaining to or characteristic of earth vibration. Also, process whereby information regarding subsurface geological structures may be deduced from sound signals transmitted through the earth.

Tar Mat
A viscous layer of oil
Water Bailer
As referenced in this report, a well that is used to extract water from a reservoir.