CANADA-NEWFOUNDLAND and LABRADOR OFFSHORE PETROLEUM BOARD

STAFF ANALYSIS

HIBERNIA DEVELOPMENT PLAN AMENDMENT

September 2, 2010

ISBN: 978-1-897101-88-9

Table of Contents

List of Tables

List of Figures

Purpose

The purpose of this document is to provide an assessment of the operations and safety, environment and resource management aspects of the development plan amendment as submitted by Hibernia Management and Development Company Ltd. (Proponent). The benefits plan amendment staff analysis is contained in a separate document.

1.0 EXECUTIVE SUMMARY

On February 1, 2010, the Proponent submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board (Board) on behalf of its partners in PL1001, PL1005 and EL1093 the following documents: "*Hibernia Development Plan Amendment January 2010 – Part I and Hibernia Development Plan Amendment January 2010 - Part II*". On February 24, 2010, the Proponent submitted an "*Amendment to the Hibernia Benefits Plan - Hibernia Southern Extension Project - January 2010*".

The development plan amendment documents discuss the status of existing developments (Hibernia B Pool, A Pool, Hibernia AA Block and the Ben Nevis-Avalon reservoir) as well as plans for future developments (Hibernia Southern Extension Unit, Catalina and Cape Island Members). They also propose that future developments will be added by utilizing existing resources and support infrastructure and by constructing subsea infrastructure.

The Proponent divides the area of the Hibernia B Pool identified as Hibernia Southern Extension into two parts: Hibernia AA Block, and Hibernia South Extension (HSE) Unit (Figure 1.1). Development of the Hibernia AA Block was approved in August of 2009. (Decision 2009.10) The development of the HSE Unit is the subject of this analysis.

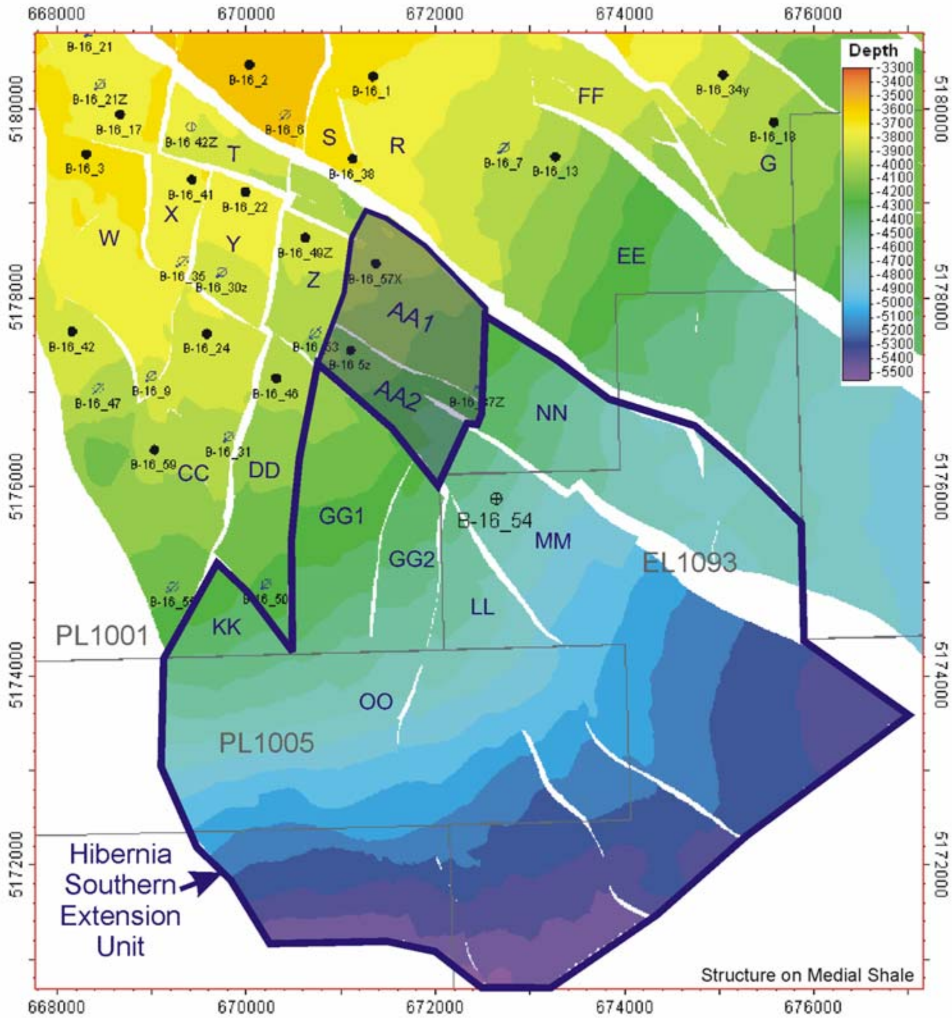


Figure 1.1: Hibernia Reservoir Southern Extension Unit Area (Source: C-NLOPB)

Staff conducted an initial review of the Benefits, Resource Management, Safety and Environment aspects of the Proponent's documents. Based on this review staff requested additional information and received supplementary information from the Proponent in April 2010.

The documents submitted in February 2010 and April 2010 constitutes the Application. This Application was made available to the public for comment on the Board's website for the period April 30, 2010 to May 31, 2010. Three comments were received (see Appendix I) and the Board's staff considered these comments in its analysis. It should be noted that the *"Hibernia Development Plan Amendment January 2010 - Part II"* document was not made available for public comment as this information is privileged under the Atlantic Accord Acts.

In reviewing the adequacy of the Benefits Plan Amendment, staff assessed it against the statutory provisions of section 45 of the legislation. Staff also relied on the interpretation of this legislation in the Board's Benefits Plan guidelines dated February 2006. In addition, the Benefits Plan Amendment was reviewed to ensure it was consistent with the Province's Hibernia South Extension Benefits Agreement (the HSE Benefits Agreement). Staff has recommended that the Benefits Plan Amendment be approved subject to condition outlined in the Benefits Plan staff analysis document.

Staff reviewed the geophysical, geological and reservoir information acquired from the Hibernia Field and surrounding area, including new wells drilled since 2006.

In the Application, it is noted that the Hibernia B Pool continues to be developed through waterflood and gasflood depletion. A Pool continues to be addressed on a well-by-well basis as resources are depleted in B Pool. This depletion scheme was accepted by the Board in 2009. The development of Hibernia AA Block was approved in Decision 2009.10 and is proceeding with three of the four planned wells now been drilled. The Ben Nevis-Avalon continues to be a staged development where ongoing development adds to the understanding of the reservoir and influences future opportunities.

In the Hibernia Southern Extension (HSE) Unit area, up to ten wells are proposed to deplete Hibernia reservoir oil reserves - five platform-based oil producer wells and five subsea water injection wells. The potential for a deeper oil-water contact and a possible extension of the Hibernia reservoir oil accumulation into PL 1005 and EL 1093 are addressed in this analysis. The Proponent's proposed drilling schedule (Figure 4.3.2.1) for the remainder of the field life indicates that drilling of the HSE Unit wells will occur from 2013 to 2015. The water injection wells will be drilled from a subsea template located 7 km southeast of the Hibernia Platform, designed for that purpose. The total development cost for this project is estimated to be $1.7 billion dollars (CDN) which includes $1.1 billion in subsea and platform drilling costs.

Development of the oil reserves in the HSE Unit area will provide an opportunity to offset oil production decline and increase levels of production for a longer period. In the short term, development of the HSE Unit area should lead to higher oil production as it will provide access to wells that are expected to produce oil at high rates with low gas content and no water. The addition of the HSE Unit will provide a significant peak of production from the GBS starting in 2013 (Figure 4.3.4.1).

The Proponent has proposed in the Application to develop the Catalina and Cape Island Members, as a staged development in the context of the development of the full Hibernia Field. Staff approves the Proponent's approach with respect to gathering information on these resources recognizing that further evaluation will be required.

Several areas for future development have been addressed in the staff analysis including natural gas liquids resources, gas commercialization and other opportunities.

With respect to the Hibernia Field, the Proponent provides an estimated base case recoverable oil resource of 1211 million barrels (193 million Sm^3) and an upside recoverable oil resource of 1466 million barrels (233 million Sm^3). Board staff recommends that the Board's Hibernia Field oil reserves estimate increase to 1395 million barrels from 1244 million barrels.

From a resource management perspective, staff recommends:

- the development of the HSE Unit be approved as described in the Application.

- the proposed approach for the development of the Catalina and Cape Island Members be approved and that production from these members should be addressed on a well-by-well basis. The progress of the development of these resources will be reviewed and updated in the Proponent's Annual Resource Management Plan.

- any other future developments will be reviewed and updated in the Proponent's Annual Resource Management Plan. The development of any of these resources will require a Development Plan Amendment.

- the Board's Hibernia Field oil reserves estimate increase to 1395 million barrels from 1244 million barrels.

With respect to the operations and safety aspects of the Application, Board staff assessed the Proponent's conceptual plans to excavate a glory hole, install subsea templates, tie-in water injection manifolds and drill subsea water injection wells utilizing a semi-submersible drilling installation for the Hibernia South Extension. In addition, the safety review of the Application included an assessment of the Proponent's plans for the installation of a gas lift system for existing and future wells. No safety concerns were identified which would preclude Staff from recommending approval of the Application. Activities in connection with this Application can be managed in accordance with established safety processes and procedures through the issuance of work authorizations.

Based on the information presented in the Application, all proposed activities are within the scope of the approved environmental assessment.

With respect to public comments received on this Application, these have been reviewed and have either been captured in the staff's analysis or will be addressed during the course of our review of applications for amendment to existing work authorizations or application for new work authorizations and/or approvals

In conclusion, the Board's staff concurs with the Proponent's Application and recommends approval of the Application subject to the following condition:

1. *HMDC, no later than six months prior to commencing seabed excavation at the Hibernia Southern Extension Unit drill center, shall submit to the Chief Conservation Officer an amended Environmental Effects Monitoring (EEM) design that incorporates drilling and production activities associated with the new drill center and tie-back to the GBS. The amended EEM Plan should be consistent with the strategy in the Hibernia Development EEM Design Report, discuss any changes that may be required to existing sampling stations, and consider the necessity for collection of baseline data at any new drill centre location.*

2.0 BACKGROUND

2.1 THE APPLICATION

On February 1, 2010, the Proponent submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board (Board) on behalf of its partners in PL1001, PL1005 and EL1093, the following documents: *"Hibernia Development Plan Amendment January 2010 – Part I and Hibernia Development Plan Amendment January 2010 - Part II"*. On February 24, 2010, the Proponent submitted an *"Amendment to the Hibernia Benefits Plan - Hibernia Southern Extension Project - January 2010"*.

Staff reviewed the documents, and on March 10, 2010 requested additional information from the Proponent. On April 7, 2010, the Proponent submitted supplementary information and on April 27, 2010, the Proponent was advised the documents were complete. The supplementary information along with the documents submitted on February 1, 2010 and February 24, 2010 constitutes the Application and was made available for public review. It should be noted that the *"Hibernia Development Plan Amendment January 2010 - Part II"* document was not made available for public comment as this information is privileged under the Atlantic Accord Acts.

The Application proposes to develop the Hibernia reservoir located in the Hibernia South Extension Unit (HSE Unit) area utilizing existing oil production facilities and support infrastructure, and by adding subsea infrastructure. This proposal represents a change to the approved Hibernia reservoir depletion scheme, as the HSE Unit was predicted to be water bearing in the original development plan. The Proponent also proposes the development of the Catalina and Cape Island Member reservoirs, using existing development wells that originally targeted the Hibernia B Pool. As there is no approved plan for depletion of resources in the HSE Unit, the Catalina and Cape Island Members, their development constitutes a Development Plan Amendment.

The Application also puts these proposals in the context of the full Hibernia field development. That is, the Application reviews existing production and infrastructure as well as other possible future developments.

The Board made the Application available to the public for comment on the Board's website for the period April 30, 2010 to May 31, 2010. Three comments were received (Appendix I). Two comments were related to benefits and are addressed in the Benefits Plan amendment staff analysis. The other is addressed in the Resource Management and Operations and Safety sections of this analysis.

With respect to the Benefits Plan, staff prepared a separate analysis on the Benefits Plan amendment for the Board's assessment. This is the first amendment to Hibernia's

Benefits Plan since the original Hibernia Benefits Plan was approved by the Board in Decision 86.01 in June 1986.

2.2 HISTORY

The Hibernia Field is located on the northeastern Grand Banks, approximately 315 km south-southeast of St. John's, Newfoundland and Labrador. The field was discovered in 1979 by drilling of the Chevron *et al.* Hibernia P-15 well.

On September 15, 1985, Mobil, on behalf of the Hibernia partners, filed the *Hibernia Benefits Plan* and *Hibernia Development Plan* with the Federal and Provincial governments. Subsequent to the appointment of the Board in December 1985, these plans were referred to the Board for review and decision. The Board conditionally approved the Proponent's plans in June 1986 in *Decision 86.01*. Since approval of *Hibernia Development Plan*, the Board has approved seven amendments to this plan.

Since Decision 86.01, development and exploitation of the field has progressed significantly. The Hibernia Field began production in November 1997. It is currently producing from the Hibernia B pool, A pool, AA Blocks and the Ben Nevis-Avalon reservoir. To date, the field has produced 693.9 million barrels (June 2010) with 94% of the oil production coming from the Hibernia reservoir. (Figure 2.1) Currently, there are 57 wells active (producing and injecting) out of the 64 platform well slots.

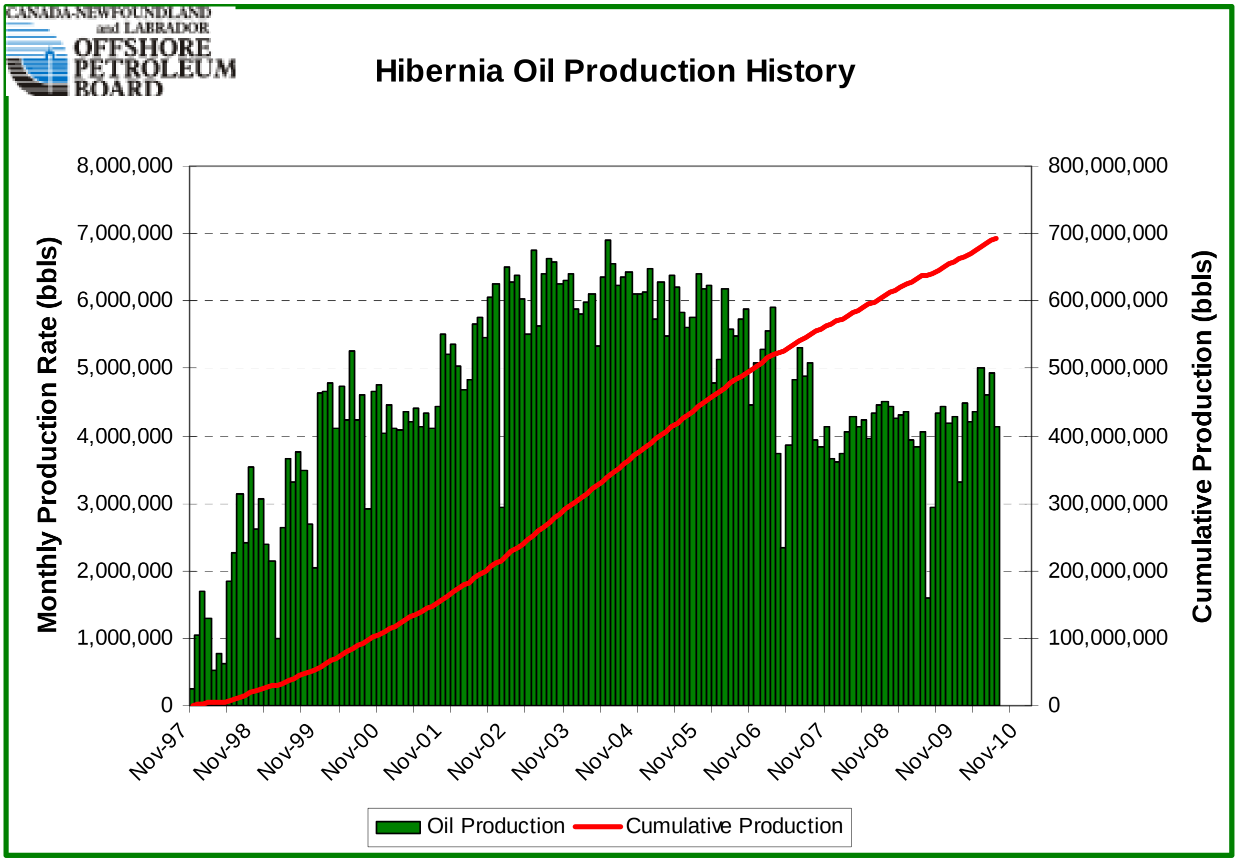


Figure 2.1: **Hibernia Oil Production History (Source: C-NLOPB)**

2.2.1 Extension of the Hibernia Reservoir Oil Accumulation

The Proponent states in the Application that drilling and reservoir performance in the last five years have confirmed that the Hibernia Field contains more oil reserves than originally estimated. Much of this increase resulted from a determination that additional reserves are located in fault blocks in the southern part of the field. These blocks, in particular AA Blocks, were previously not expected to contain oil (*Decision Report 2003.01*), and therefore were not considered part of the approved Development Plan. However, further development drilling revealed a deeper oil-water contact in the Hibernia reservoir, resulting in an expansion of the southern extent of the field. This implies that the Hibernia reservoir oil accumulation extends into the AA1, AA2, GG1, GG2, KK, LL, MM, NN and possibly OO fault blocks (Figure 2.2).

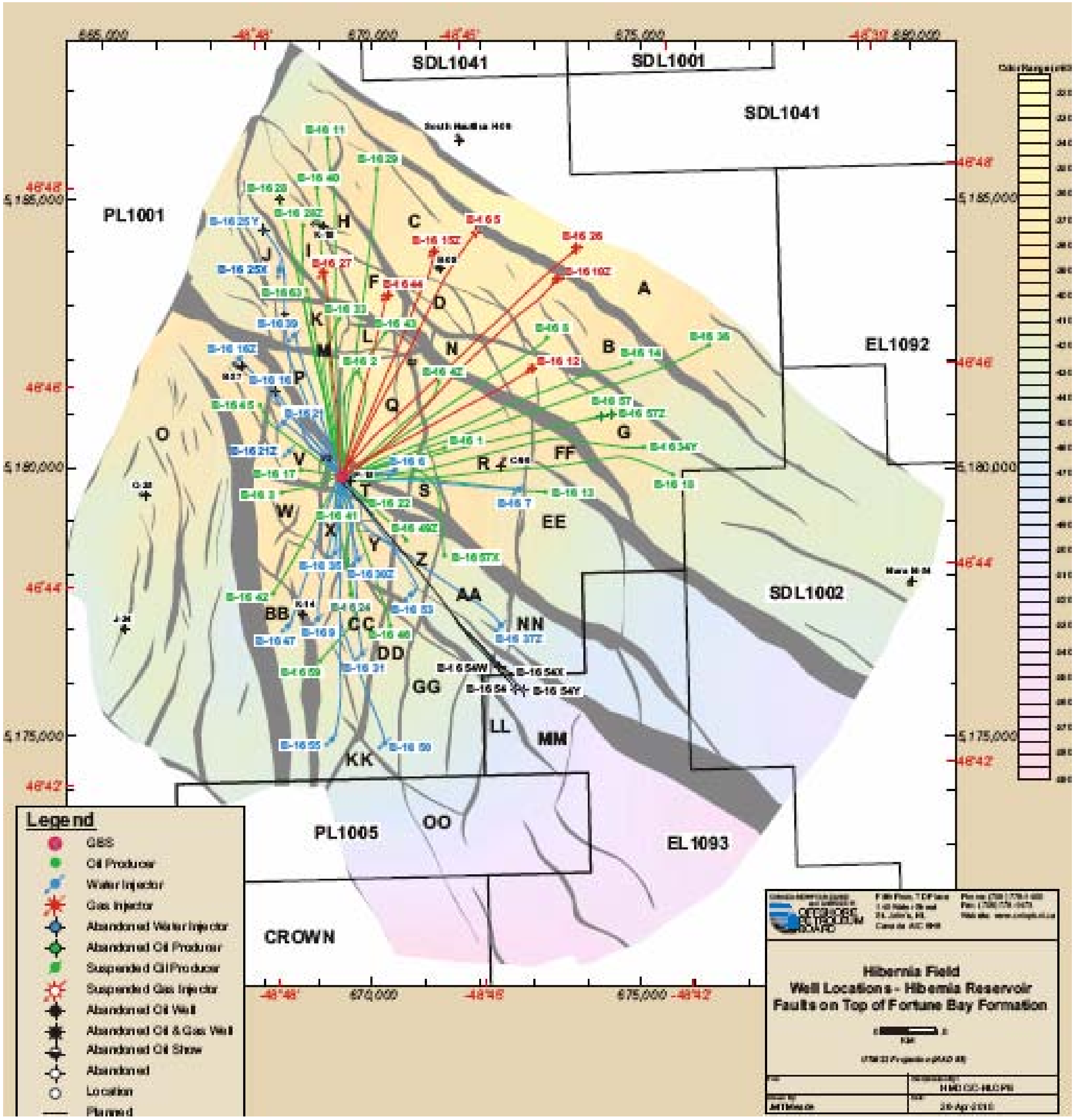


Figure 2. 2: Map of Hibernia Field (Source: C-NLOPB)

The expansion of the field to include the HSE area oil accumulation is the most significant change to date from the approved Development Plan in Decision 86.01, and has resulted in an increase in reserves for the overall Hibernia Field.

As shown in Figure 2.3, the Hibernia reservoir is a large roll-over anticline. The depth of the oil-water contact along the flanks of the structure controls the aerial extent of the oil accumulation.

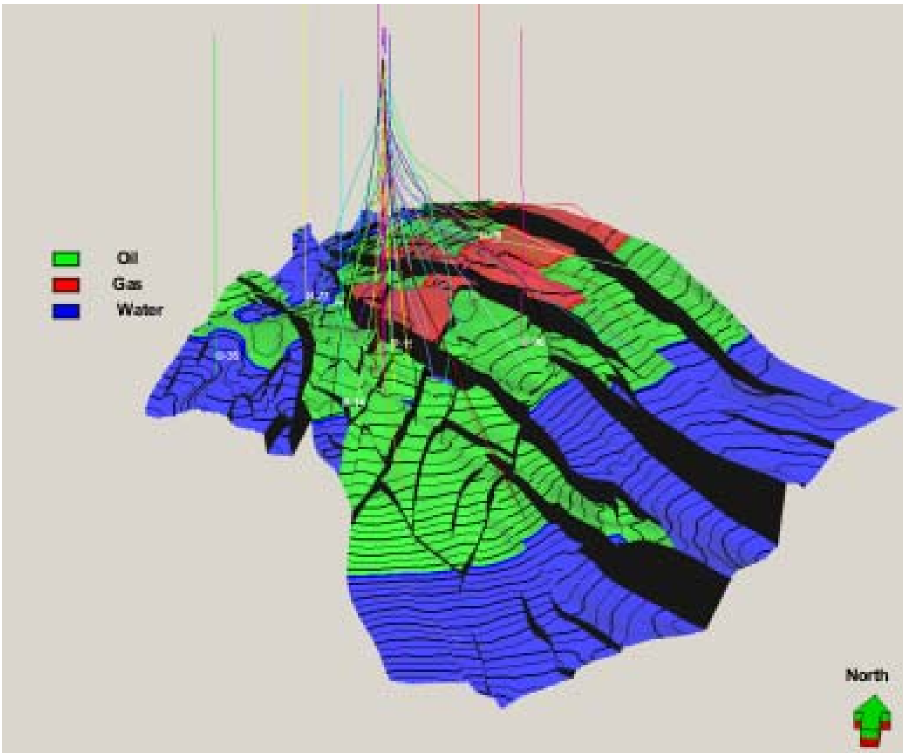


Figure 2.3: Depth-Structure Map of Hibernia Field Showing Fluid Contacts (Source: C-NLOPB)

At the time of approval of the Hibernia Development Plan in 1986, the depth of the oil-water contact was uncertain in many parts of the field. In Decision 86.01, Board staff reported that the oil-water and gas-oil contacts used by the Proponent for the Hibernia sandstones were acceptable for planning purposes. However, the pressure/depth data indicated the presence of multiple hydrostatic pressure systems and the possibility of multiple additional oil-water contacts.

The early stages of development drilling at the Hibernia Field confirmed that the oil-water contact was deeper than the 3930 m TVDss assumed as a basis for initial development planning. Table 2.1 shows the progression of the Board's interpretation of oil-down-to and oil-water contacts in the Hibernia reservoir as development drilling occurred.

Table 2.1: Summary of Oil-Down-To and Oil-Water Contacts for Hibernia Reservoir at Hibernia Field. (Source C-NLOPB)

Year	Well	Area	Fault Block	
1986				Hibernia Development Plan 3930 m TVDss
1998	B-16 7	Central	R	Confirmed oil down to 3935 m TVDss
1999	B-16 14	North	B	Confirmed oil down to 3980 m TVDss
2000	B-16 18	North	G	Encountered oil-water contact at 3996 m TVDss. Data suggest that oil-water contact may be as deep as 4030 m TVDss
2001	B-16 24	South	CC	Confirmed oil down to 3950 m TVDss
2002	B-16 31	South	CC	Confirmed oil down to 4030 m TVDss
2004	B-16 46	South	DD	Confirmed oil down to 4060 m TVDss
2005	B-16 50	South	DD	Confirmed oil down to 4333 m TVDss
2006	B-16 13	Central	EE	Encountered an oil-water contact at 4014 m TVDss
2006	B-16 54	South	MM	Limited data suggests oil down to 4600 m TVDss

Integration of drilling and production data acquired from the Hibernia Field since production began in 1997 has contributed to a number of revisions to recoverable reserves estimates for the field. Table 2.2 presents the most likely reserves estimates provided by the Proponent as well as the reserves estimates reported by the Board. From Table 2.2, it can be observed that there was a steady increase in the Proponent's reserves estimates from 1985 to 2009. In this Application, the Proponent has reduced its most likely reserves estimate by 54.7 million barrels (4.3%), due to a revised geological interpretation in the HSE Unit**.** (See Appendix A for more details)

Table 2.2: Summary of Most Likely Oil Reserves Estimates for Hibernia Field

	Oil Reserves in Millions of Barrels (Millions Sm^3)	
Year	**Proponent**	**C-NLOPB**
1986	522 (83)	711 (113)
1996	616 (98)	666 (105)
2000	750 (119)	884 (140)
2002	780 (124)	865 (138)
2006	1203 (191)	1244 (198)
2009	1265 (201)	1244 (198)
2010	***1211 (193)***	***1395 (222)***

Numerous factors have contributed to the change in oil reserves estimates for the Hibernia Field. Acquisition of additional information from drilling and production activities has contributed significantly to a better understanding of the field. This information enabled the Proponent to construct improved geologic and reservoir simulation models that allow the Proponent:

- to better estimate the oil-in-place and gas-in-place volumes;
- to assess performance of the waterflood and gasflood exploitation schemes; and
- to assess the merits of alternate exploitation schemes.

The 2010 reserves estimates are discussed later in the Resource Management section of this report.

2.2.2 Definition of Hibernia Field

Several pools within the Hibernia Field oil accumulation have been formally defined by the Chief Conservation Officer. In terms of the general surface area of a field, the Significant Discovery Area or the Commercial Discovery Area provide for the maximum extent of known hydrocarbon accumulations identified in relevant discovery and delineation wells. These areas are used to define the field boundary. Both the Significant Discovery and Commercial Discovery Areas, as appropriate, may be reduced or expanded based on drilling results. In October 2002, the Board extended the Hibernia Commercial Discovery Area based on development drilling information. Production Licence 1005 was subsequently issued in January 2004.

The Board's staff has considered geophysical, geological and pressure data acquired from the field and surrounding area. The staff concluded, on the basis of this engineering and geoscience information, that the oil accumulation in the HSE Unit area is within the Hibernia feature drilled by the Hibernia P-15 discovery well. Also, the pressure data acquired from Hibernia B-16 54W suggested that the oil accumulation encountered in this well is also part of the same oil accumulation encountered by up-dip Hibernia development wells.

In conclusion, the Board's staff believes the HSE Unit area oil accumulation is part of the Hibernia Field and is not a new field. The information gained by drilling the B-16 54 well and its sidetracks provides a basis for extending the Hibernia Commercial Discovery Area to include a portion of Exploration License 1093. The inclusion of EL 1093 into the Hibernia Commercial Discovery Area will be addressed in a separate application process that is not dealt with in this analysis.

2.2.3 Status of Hibernia Conditions

A listing of the status of Hibernia conditions is in Appendix H. This contains an update of the conditions since 2003.

3.0 PROTECTION OF THE ENVIRONMENT

The Board's staff has reviewed the Proponent's Application to determine whether this Development Plan Amendment raises any new environmental issues. Based on the information presented in the Proponent's documentation, the proposed activities are within the scope of the original environmental assessment and the Hibernia Drill Centers Construction and Operations Program environmental assessment.

HMDC will be required to implement, or cause to be implemented, all the policies, practices, recommendations and procedures for the protection of the environment included in or referred to in the Screening Report "Hibernia Drill Centers Construction and Operations Program Hibernia Management and Development Company (HMDC)" (report updated by Stantec in 2010).

The currently approved Hibernia Environmental Protection Plan (EPP) as described in Section 5 of the Hibernia Operational Plan will continue to apply to all developments detailed in the Application. The EPP and its supporting documents should be revised as necessary to reflect the addition of any subsea developments.

The approved Hibernia EPP includes an Environmental Effects Monitoring program to monitor drilling and production discharges. HMDC will be required to amend its EEM program to account for Hibernia Southern Extension Unit activities.

The Board's staff has concluded that the Application does not require additional environmental assessment pursuant to the Canadian Environmental Assessment Act.

It is a condition of this approval that:

> *HMDC, no later than six months prior to commencing seabed excavation at the Hibernia Southern Extension Unit drill center, shall submit to the Chief Conservation Officer an amended Environmental Effects Monitoring (EEM) design that incorporates drilling and production activities associated with the new drill center and tie-back to the GBS. The amended EEM Plan should be consistent with the strategy in the Hibernia Development EEM Design Report, discuss any changes that may be required to existing sampling stations, and consider the necessity for collection of baseline data at any new drill centre location.*

4.0 RESOURCE MANAGEMENT

4.1 Application Summary

The Application includes a discussion of the following resource management aspects:

- Updates on production and development for the Hibernia B Pool, Hibernia AA Blocks and Hibernia A Pool;
- Proposed development of the Hibernia Southern Extension Unit (B Pool);
- Update on production and development for the Ben Nevis-Avalon reservoir;
- Proposed development of the Catalina Member and Cape Island Member within the Hibernia Field;
- An assessment of integrated development for the full field that includes a preliminary assessment of the deferred developments, criteria for a full-field development schedule, discussion of slot optimization, an updated production forecast and an update to the field economic life. Gas resources in the Hibernia Field are addressed as a deferred development opportunity.

The Application also contains information regarding geological, geophysical, petrophysical, reservoir simulation and production forecasting models. Summaries of the staff's analysis with respect to the following reservoirs and pools are included in Appendices A-G:

- Hibernia B Pool (full field, excluding HSE Unit)
- Hibernia AA Blocks
- Hibernia Southern Extension Unit (B Pool only)
- Hibernia A Pool
- Ben Nevis-Avalon reservoir
- Catalina Member
- Cape Island Member

Staff used the Proponent's information, as well as its own data and models, in its analysis of the Application.

4.2 Full Field Development

4.2.1 Overview

Development of the Hibernia Field is an integrated development of the main Hibernia B Pool reservoir, Ben Nevis-Avalon reservoir, Hibernia A Pool and several deferred secondary developments. According to the Proponent, the total field, including deferred development of secondary reservoirs, contains approximately 3625 million barrels (576.0

million m^3) of stock tank original oil in place (STOOIP) and 3924 billion cubic feet (111 billion m^3) of gas. The current Gravity Based Structure (GBS) well count (as of June 2010) is 57 active wells out of the possible 64 well slots.

The Proponent divides the area of the Hibernia B Pool identified as Hibernia Southern Extension into two parts for the purposes of this Application: Hibernia AA Block, and Hibernia South Extension (HSE) Unit. Development of the Hibernia AA Block was approved in August of 2009 (Decision 2009.10) and there have been no changes to the depletion plan for the AA Block since that time. This Application primarily addresses the B Pool development in the area referred to as the HSE Unit.

The secondary reservoirs shown in Figure 4.1 are included in the combined development of the Hibernia Field. The Ben Nevis-Avalon (BNA) is the largest of the four in terms of resources and development to date. The other three reservoirs are smaller and less developed. They include Hibernia A Pool, the Catalina Member and the Cape Island Member. Development of the Hibernia A Pool was approved in 2009 and is ongoing. The Proponent has proposed the development of those other members in this Application.

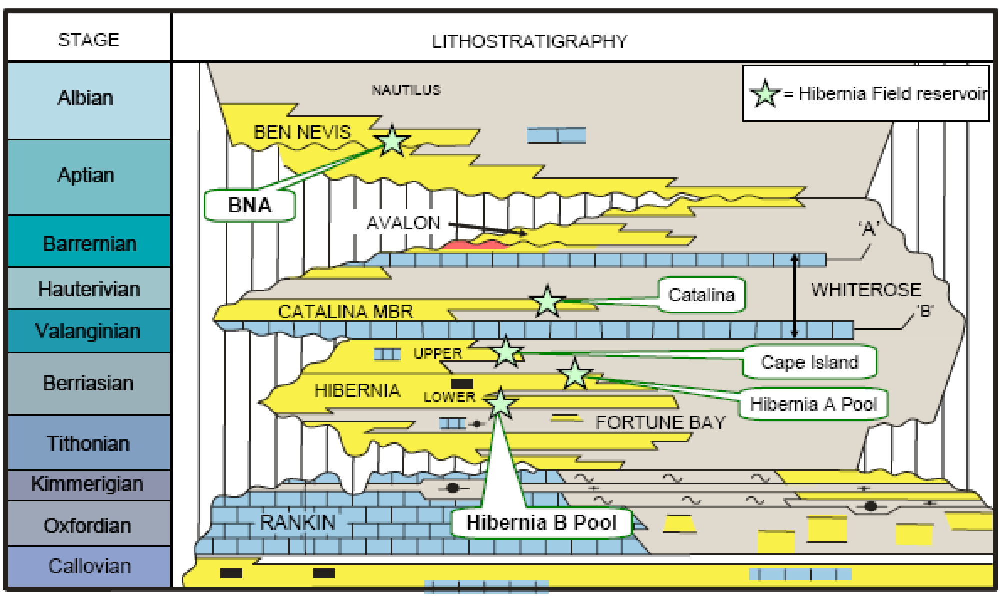


Figure 4.1: Hibernia Field Stratigraphy. Sandstone Reservoirs in Yellow (Source: HMDC)

4.2.2 Geology and Geophysics

The Proponent submitted a revised Petrel geological model for the Hibernia reservoir in the HSE Unit area. Other reservoirs and areas of the field addressed in the Application either were represented by models previously submitted to the Board, or were not able to be modeled due to complexity or lack of data.

4.2.2.1 HSE Unit

The Hibernia B Pool reservoir in the HSE Unit is expected to share similar reservoir characteristics with the remainder of the field in terms of lithologies and reservoir connectivity. However, the Proponent anticipates two important differences in reservoir quality in the HSE Unit. Firstly, porosity and permeability are expected to be lower than in the main part of the field, due to cementation and compaction related to deeper burial. Secondly, the Proponent has mapped a possible facies change toward the southeast that is expected to result in an increase in shale content and a decrease in overall reservoir thickness and quality in the outlying parts of the HSE Unit. This facies change was not recognized in the June 2009 DPA submission.

Seismic data for the HSE Unit has also been re-interpreted since 2009, leading to changes to the structural framework for the geological model. The result is a previously unrecognized thinning of the Hibernia reservoir toward the southeast. Combined with the degradation of reservoir quality and the changes in facies distributions noted above, the structural re-interpretation leads to a significant decrease in bulk reservoir volume, reservoir pore space, and ultimately, oil in place for the HSE Unit compared with the 2009 estimate.

Board staff acknowledges that these changes represent reasonable, though conservative, interpretations. The Board’s models and reserves estimates have not been revised to account for these changes at this time. Staff anticipates that drilling results from the initial wells in the HSE Unit will verify the validity of the Proponent’s changes to the model.

4.2.2.2 Catalina Member

The Catalina Member of the Whiterose Formation consists of interbedded shales and thin sandstones, interpreted to have been deposited in a marginal marine/delta environment. The gross thickness of the Catalina ranges from 250 to 350 metres. According to the Application, net sandstone thickness is typically no greater than 4-10 metres. Mapping by Board staff indicates that net pay in existing wells is somewhat thicker, from 5-21 m.

Because of the thin and discontinuous nature of Catalina Member sandstones, limited log data and the limits of seismic resolution, geological modeling of the Catalina is difficult. Board staff agree with the Proponent’s assessment that reservoir quality is generally poor over some portions of the field; however, preliminary analysis by Board staff suggests that areas of high quality reservoir do exist, and further assessment is required. The Proponent has indicated that it is working on improving analysis of the Catalina reservoir. A summary of this work will be submitted to the Board upon completion.

4.2.2.3 Cape Island Member

The Cape Island Member constitutes the uppermost part of the Hibernia Formation, and consists of a series of thin sandstones interbedded with thick silty shales.

Board staff agree with the Proponent's assertion that the heterogeneous and discontinuous nature of the Cape Island Member is likely to result in several small, unconnected hydrocarbon accumulations. Preliminary mapping by Board staff suggests that individual sandstones within the Cape Island occur in elongate trends, roughly oriented southwest-northeast.

Because of the thin and discontinuous nature of Cape Island sandstones, the scarcity of log data and the limits of seismic resolution, geological modeling is very difficult. The Proponent has indicated that it is working on improving analysis of the Cape Island Member. A summary of this work will be submitted to the Board upon completion.

4.2.3 Petrophysics

The Proponent has conducted a comprehensive logging and coring program of the Hibernia A and B Pools and the Ben Nevis-Avalon reservoir while drilling exploration, delineation and development wells in the Hibernia Field. In Part II of the Application, the Proponent summarized its petrophysical interpretation for wells in each of the field's reservoirs. The Proponent supplied supplemental information on the methodology, assumptions and criteria used in the Hibernia Formation petrophysical analysis.

Staff reviewed the petrophysical data and determined that the Proponent's interpretation of the Hibernia A and B Pools and the Ben Nevis-Avalon reservoir is similar to staff's assessment, with slight differences attributed to different methodology, assumptions and criteria used in interpreting the data. Based on its analyses, Board staff believe the interpretation presented by the Proponent is reasonable and appropriate to evaluate the Application.

The Proponent also provided a summary of the Cape Island Member, in addition to the methodology used in assessing this unit. All wells that encountered porous sands in the Cape Island Member have a resistivity profile that suggests they are hydrocarbon bearing. Eight wells have a net pay greater than three metres using a 10% porosity cut-off. This cut-off may be optimistic, as there are no cores in the Cape Island Member, so a porosity-permeability relationship cannot be established.

Many Hibernia B Pool wells intentionally penetrated poor quality or faulted out Catalina Member strata in order to avoid drilling challenges within the unit. This has resulted in sporadic data collection in this interval. Only a small number of wells have good quality log data over the complete Catalina Member.

Board staff believe that future strategic data acquisition will enhance all parties' understanding of the resource potential of the Cape Island and Catalina Members.

4.2.4 Stock Tank Original Oil In Place (STOOIP)

The following table displays the Proponent's STOOIP estimate for the Hibernia Field based on volumetric assessment, compared with the Board's assessment.

Table 4.2.4.1 Hibernia Full-Field STOOIP Assessment (Source: C-NLOPB)

Pool	STOOIP (MMbbls) CNLOPB (2006)	STOOIP (MMbbls) HMDC (2010)	Difference
Hibernia B Pool	1723	1464	+259.0
Hibernia AA Blocks	124.7	117	+7.7
Hibernia HSE Unit	378.4	261	+117.4
BNA (Total)	1893	1539	+354.0
Hibernia A Pool	177.2	135	+42.2
Catalina	138	103	+35.0
Cape Island	N/A	8	-8.0
Total	4434.3	3627	**+807.3**

The Proponent's estimate for the Hibernia HSE Unit assumes a most likely case of an oil-water contact at 4816 m TVDss, based on a reservoir juxtaposition interpretation. As discussed in Section 4.2.2, the Proponent's structural reinterpretation has resulted in an upward shift in depth of the southeastern part of the field, and reservoir quality is also expected to degrade toward the southeast. These two factors result in a lower STOOIP estimate than previously presented by the Proponent.

The Proponent acknowledges that the estimates for the Hibernia A Pool, the BNA and the Catalina Member are preliminary at this time, and estimates will become more refined as more data becomes available from drilling. Volumetric estimates for the Cape Island Member are tentative, and based on analysis of limited data by both the Proponent and the Board's staff.

4.2.5 Reservoir Engineering

The reservoir engineering details for each of the reservoirs and pools is specifically addressed in the individual appendices where appropriate.

4.2.5.1 Reservoir Modeling – Full Field Development

The reserves estimates and production profiles presented in the Application were generated from the Proponent's Hibernia full-field model. The Hibernia full-field model is made up of six individually built sector models controlled by a complex set of Well Management Logic. The six Hibernia sector models include two for the Ben Nevis-Avalon reservoir and four for the Hibernia B and A pools, including North Sector, Middle Sector JKL Sector and South & HSE Sector Model. The Proponent's Well Management Logic allows the simulator to account for field oil, gas and water processing and injection capacities and field management strategies.

Since the June 2009 DPA, the Proponent has made significant changes to the geological model representing the HSE Unit. Those changes are reflected in the reservoir simulation model. The Proponent has yet to develop a reservoir simulation model that encompasses the Catalina and Cape Island Members.

The Proponent used in-house reservoir simulation software rather then a commercially available reservoir simulation package. The Proponent has discussed the development logic, inputs, constraints and results of its reservoir simulation model with Board staff, and its reservoir simulation model has been determined to be reasonable. Board staff will continue to look for updates of the model as more information, particularly in the HSE Unit area and the Catalina and Cape Island Members, becomes available.

4.2.5.2 Reserve Estimates – Full Development

The Proponent's oil reserves presented in Table 4.2.5.1 are within the range of 1059 to 1466 million barrels (168 to 233 million m^3) of oil and NGL's recoverable.

Table 4.2.5.1: Field Oil Recovery Range (Source: HMDC)

Reservoir	Upside Recoverable		Most Likely Recoverable		Downside Recoverable	
	(Mm3)	(MB)	(Mm3)	(MB)	(Mm3)	(MB)
Hibernia B Pool (Non HSE Unit)	152.0	956.3	145.0	911.8	132.7	834.4
Hibernia AA Blocks	11.1	69.8	7.7	48.4	5.9	37.0
Hibernia (HSE Unit)	26.9	169.3	17.1	107.6	10.9	68.3
Ben-Nevis Avalon (Non HSE Unit)	34.6	217.4	17.3	108.5	14.7	92.5
BNA (HSE Unit)	5.1	32.0	4.2	26.7	3.6	22.8
Hibernia A Pool	2.2	14.0	1.3	8.4	0.7	4.1
Catalina	1.1	6.9	0.0	0.0	0.0	0.0
Cape Island	0.1	0.4	0.0	0.0	0.0	0.0
Total	233	1466	193	1211	168	1059

The Board's 2006 Hibernia recoverable reserves review reported a P50 of 1446 million barrels which includes 1244 million barrels of oil and 202 million barrels of NGL's, and an upside oil reserve estimate of 1916 million barrels (305 million m^3).

Several of the main Hibernia reservoir B Pool blocks have outperformed the Board's estimated ultimate recovery from the 2006 reserves assessment. In all blocks of the gasflood region and selected blocks of the waterflood region, a revision of the reserves estimate was conducted using decline trends of wells that have outperformed the latest estimates. In the gasflood region, the Board's reserves estimate is being increased from 277.8 million barrels to 387.3 million barrels. The Proponent's reserves estimate for this region is 426.8 million barrels.

In the waterflood region, a reassessment was conducted on K, L, Q, R, V, BB, EE, X, Y and Z Blocks. Analysis of the production data from these blocks shows that reserve estimates should be increased in all but the EE Block. In total, the Board's reserves estimate in the waterflood area has increased from 275.7 million barrels to 316.9 million barrels. The Proponent's reserves estimate for these select blocks is estimated at 315.9 million barrels.

It is beyond the scope of this analysis to conduct a full re-assessment of Hibernia Field reserves and resources. However, production decline analysis from the main Hibernia B Pool reservoir indicates that it is reasonable to increase the Board's reserve estimate from 1244 million barrels to 1395 million barrels. A more detailed description of the reserves revision for B Pool is contained in Appendix B of this document.

The upside estimate provided by the Proponent incorporates several assumptions, including 10% improved recovery in Hibernia B Pool and additional developments of BNA fault blocks. It also assumes a deeper oil-water contact in the southern part of the field and better reservoir quality than the most likely prediction. The Board's upside reserves estimate is also based upon a deeper oil-water contact, better recovery from the BNA and a higher recovery rate from the Catalina Member.

Staff is encouraged by the Proponent's progress in improving BNA development with drilling in 2008 in the northwest wedge area. The Board's staff notes that while recovery in selected areas currently proposed for development are within industry norms (i.e. 25-30% recovery), the overall BNA recovery is below industry norms. The Proponent is continuing to explore ways to best exploit the oil resources in the Ben Nevis-Avalon reservoir, including the application of new technologies and approaches to recovering these resources. As a condition of approval of the Ben Nevis-Avalon Development Plan, these activities will be reported annually in the Proponent's Annual Production Report. The Board's staff will continue to monitor development activities for this reservoir.

As discussed earlier, the Proponent reports a most likely oil reserve of 107.6 million barrels (17.1 million m^3) for the HSE Unit, and an upside potential of 169.3 million barrels (26.9 million m^3). This assessment is considerably less than the Proponent's reserves estimate for the HSE Unit from the June 2009 DPA (AA Blocks), which had a most likely oil reserve of 171.6 million barrels (27.3 million m^3) and an upside potential of 280.2 million barrels (44.6 million m^3). This reduction is primarily due to the Proponent's reassessment of the HSE Unit geological model that predicts thinning to the southeast, as opposed to a constant thickness as was previously assumed. The Board's most likely estimate of oil reserves in the HSE Unit is 167 million barrels (26.6 million m^3). While the Board considers the Proponent's reassessment of the HSE Unit geological model to be possible, this model has yet to be fully accepted by the Board.

Other secondary reservoirs are listed by the Proponent with upside recoverable estimates, such as the Catalina with 6.9 million barrels (1.1 million Sm^3), and the Cape Island with 0.4 million barrels (0.1 million Sm^3). These estimates could be conservative and will be subject to future assessment by staff and the Proponent.

Table 4.2.5.2:Field Oil Recovery Range (Source: C-NLOPB)

Pool	Recoverable Reserves (MMbbls) CNLOPB (2010)	Recoverable Reserves (MMbbls) HMDC (2010)	Difference
Hibernia B Pool	963.3	911.8	**+51.5**
Hibernia AA Blocks	48	48.4	**-0.4**
Hibernia HSE Unit	167	107.6	**+59.4**
BNA (Total)	182	135.2	**+46.8**
Hibernia A Pool	35	8.4	**+26.6**
Catalina	0	0	**0**
Cape Island	0	0	**0**
Total	1395.3	1211.4	**+183.9**

In conclusion, the oil reserves estimates provided by the Proponent for the most likely case of 1211 million barrels is considered a conservative but possible estimate for the Hibernia Field. The Board's estimate of 1395 million barrels is an increase from the 2006 assessment based on strong performance from the Hibernia B Pool. It should be noted that there is uncertainty existing in STOOIP volumes, production performance and recovery factors. These estimates will continue to be reviewed and updated as new information is acquired.

4.3 Full Reservoir Exploitation

4.3.1 Integrated Development Criteria

The Proponent describes in the Application the criteria used to define the optimum timing for developing deferred reservoirs as follows:

1) Hydrocarbons in-place and recoverable;
2) Productivity;
3) Reservoir risk;
4) Value of information; and,
5) Drilling considerations

These criteria are considered reasonable, as they provide for resource management considerations including maximization of all resource recovery, facilities optimization and the prevention of waste.

4.3.2 Development Schedule

The Proponent's proposed drilling schedule (Figures 4.3.2.1) for the remainder of the field life indicates that drilling of the HSE Unit wells will occur from 2013 to 2015. As previously described in the HSE Unit development strategy, production wells will be drilled from the Hibernia Platform. Water injectors in the HSE Unit are planned for drilling commencing in Q2 2013, from a subsea template planned for construction during the summer of 2012.

Prior to the development of the HSE Unit, the Proponent plans to complete a second well pair in the AA Block and devote considerable rig time to converting a number of well completions to gas lift completions in advance of implementing gas lift on the Hibernia Platform. Gas lift implementation is scheduled for 2012.

The development of the HSE Unit falls in line with the combined development of the Hibernia Field and the drill times presented for the HSE Unit wells are consistent with past drilling performance on the Hibernia Platform. Board staff recognize that the long-term drilling schedule is dependent on field performance and needs, and that there is enough flexibility in the schedule to accommodate potential future development. On this basis, the Board's staff concludes that the proposed drilling schedule is reasonable.

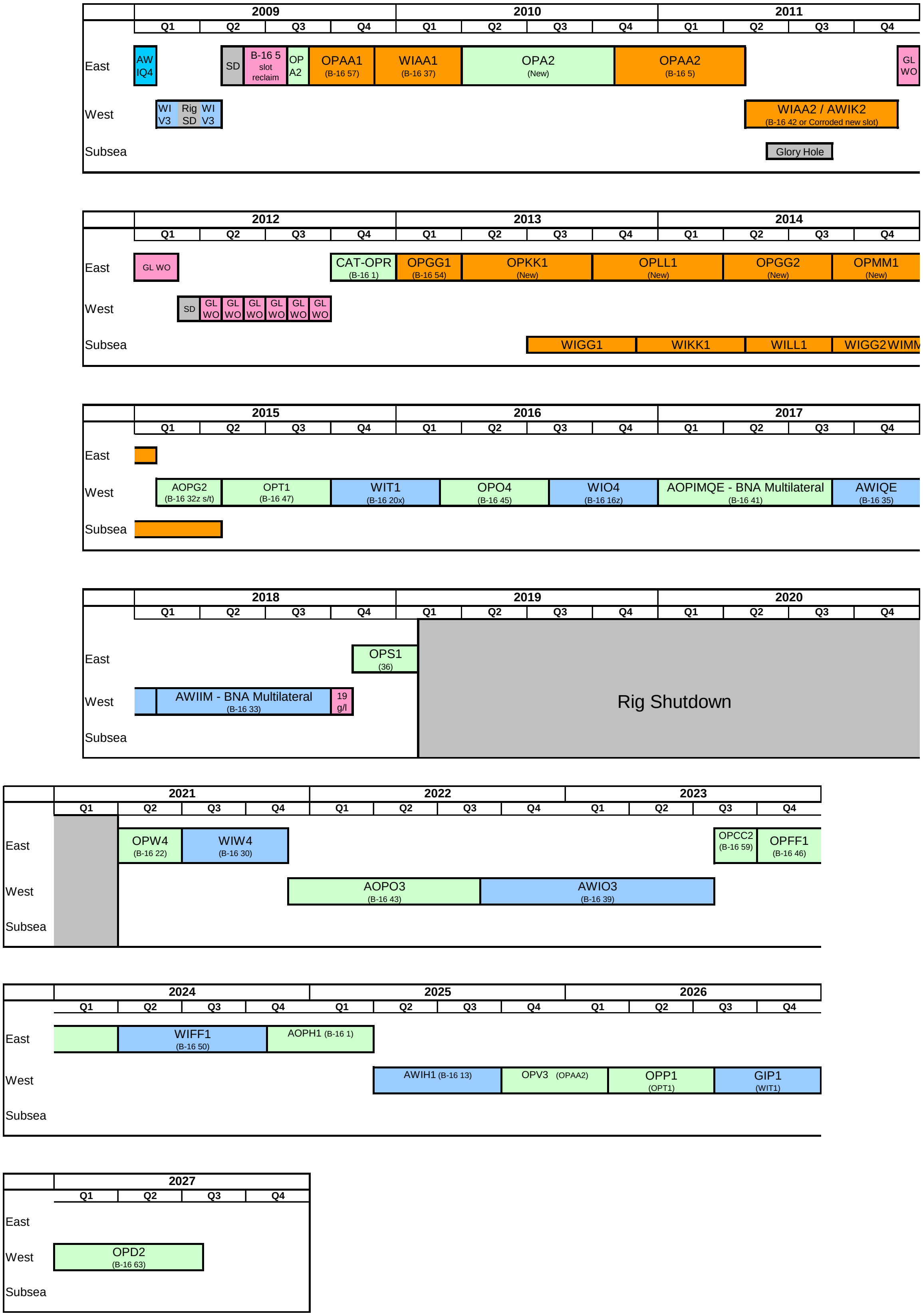


Figure 4.3.2.1: Drilling Schedule for Each Rig and Slot Allocation (Source: HMDC)

4.3.3 Slot Optimization

Figure 4.3.3.1 shows the November 2009 Hibernia GBS well slot configuration. The Proponent's plan is to utilize five slots to develop HSE Unit production wells along with a subsea template to develop the water injection wells. Based on the Proponent's drilling schedule (above), staff concludes that the HSE Unit development slot optimization strategy is reasonable.

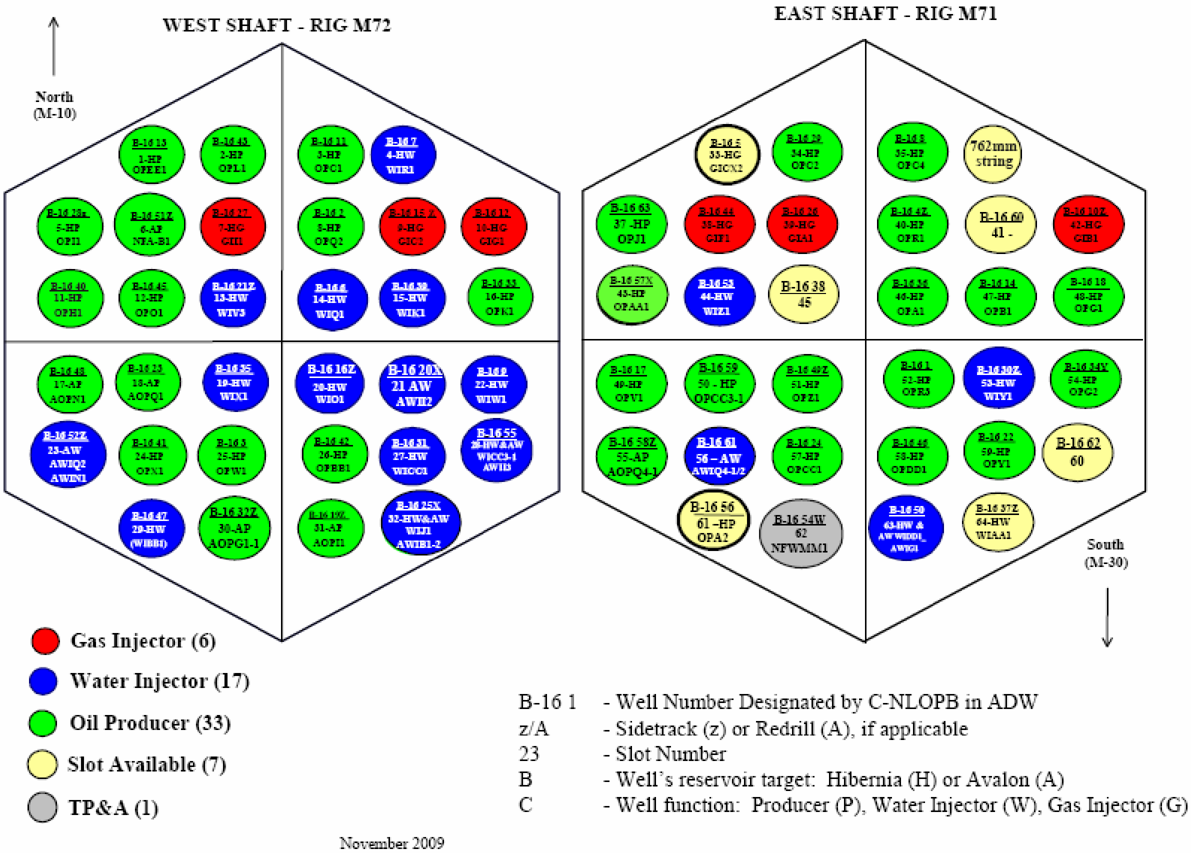


Figure 4.3.3.1: Hibernia Drill Slot Assignments (Source: HMDC January 2010)

Board staff reviewed *GBS Slot Additions Technical Feasibility Assessment* and *Hibernia Debottlenecking and Expansion Report*, both submitted as Part II supplemental documents to this Application, and agree with the Proponent's assessment that it is not feasible to add additional slots to the Hibernia Platform. Any further development opportunities will be dependent on reclaiming slots following the production life of developed wells, or through subsea development tied back to the platform through the existing J-tubes.

4.3.4 Production Forecast

The Board's staff has reviewed the oil production forecasts provided by the Proponent (Figure 4.3.4.1). Several assumptions could affect the forecasts, including drilling schedule, criteria to determine when zones, pools and wells are shut-in, operational upsets and assumptions related to well slot availability.

The Proponent's production forecast for Hibernia Field appears reasonable. According to the Hibernia full-field forecast, the HSE Unit will provide the last significant peak of production (See figure 4.3.4.1) from the Hibernia Platform and will reach peak production in 2015, averaging 46,500 barrels per day, two years following initial production in 2013.

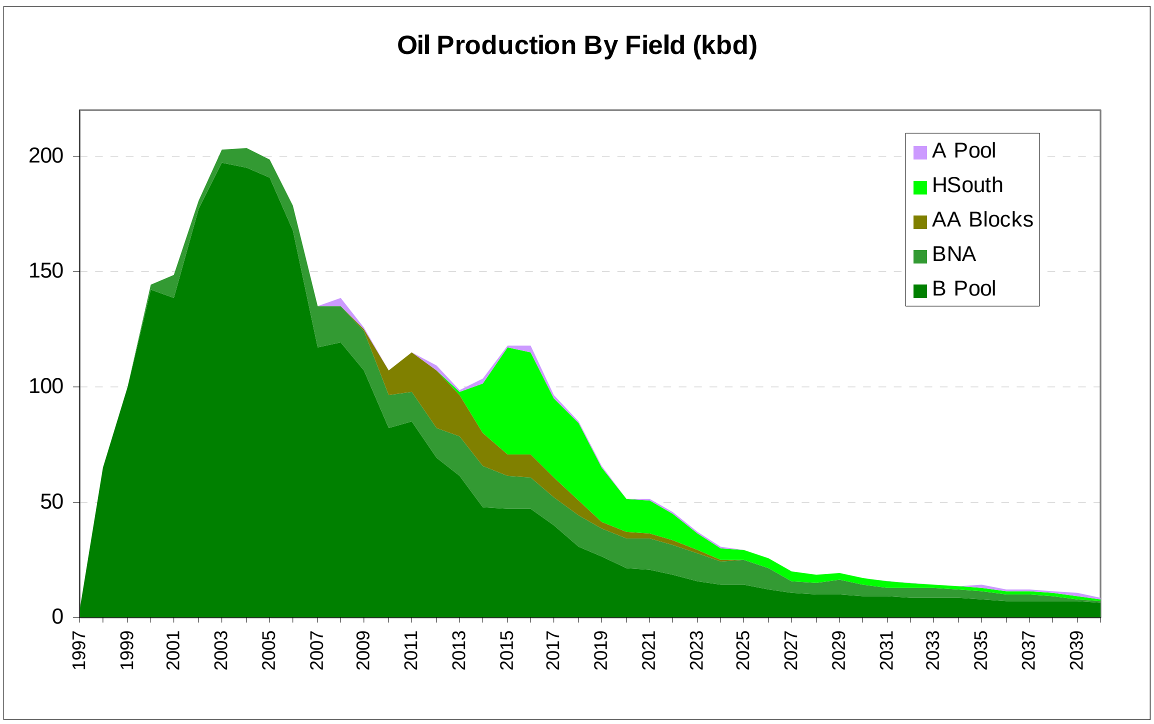


Figure 4.3.4.1: Hibernia Full-Field Production Forecasts for Each Reservoir, Pool or Unit (Field Units) (Source: HMDC)

Table 4.3.4.1 also highlights a significant production shift over the next six years, starting in 2009, from the Hibernia B Pool to deferred reservoir developments. Production from the original Hibernia B Pool (excluding AA Block) will go from 85% of the total platform production in 2009 to an estimated 40% in 2015. This shift in production is due to the onset of production from what was originally considered the Hibernia Southern Extension, comprised of the AA Blocks and the HSE Unit.

The field life for the Hibernia development presented in this Application is significantly different from what the Proponent presented in the June 2009 DPA addressing the AA Block. That is, the Proponent indicates that the field life has been extended from 2036 to

2040.

Table 4.3.4.1: Hibernia Production Forecast for Most Likely Case (Source: HMDC)

	Most Likely Oil Production (kbd)							
Year	Total	B Pool	AA Blocks	HSE Unit	BNA	A Pool	Catalina	Cape Isl
1997	3.5	3.5	0.0	0.0	0.0	0.0	0.0	0.0
1998	65.2	65.2	0.0	0.0	0.0	0.0	0.0	0.0
1999	99.7	99.7	0.0	0.0	0.0	0.0	0.0	0.0
2000	144.2	141.9	0.0	0.0	2.4	0.0	0.0	0.0
2001	148.7	138.7	0.0	0.0	10.1	0.0	0.0	0.0
2002	180.5	177.3	0.0	0.0	3.1	0.0	0.0	0.0
2003	203.1	197.4	0.0	0.0	5.7	0.0	0.0	0.0
2004	203.6	194.8	0.0	0.0	8.7	0.1	0.0	0.0
2005	198.9	191.1	0.0	0.0	7.8	0.0	0.0	0.0
2006	178.4	168.1	0.0	0.0	10.2	0.0	0.0	0.0
2007	134.9	117.4	0.0	0.0	17.4	0.0	0.0	0.0
2008	138.6	119.3	0.0	0.0	15.8	3.6	0.0	0.0
2009	125.6	106.9	0.7	0.0	17.2	0.8	0.0	0.0
2010	107.2	82.3	10.5	0.0	14.2	0.3	0.0	0.0
2011	115.0	85.2	17.2	0.0	12.7	0.0	0.0	0.0
2012	109.1	69.6	25.2	0.0	12.4	1.8	0.0	0.0
2013	98.5	61.6	18.2	1.3	16.9	0.5	0.0	0.0
2014	103.8	47.6	14.1	21.7	18.3	2.1	0.0	0.0
2015	118.0	46.9	9.5	46.5	14.4	0.7	0.0	0.0
2016	117.5	47.0	10.0	44.1	14.0	2.5	0.0	0.0
2017	96.1	40.3	8.6	34.9	11.5	0.8	0.0	0.0
2018	84.8	30.7	6.6	33.2	13.7	0.6	0.0	0.0
2019	65.7	26.3	3.4	23.6	11.9	0.4	0.0	0.0
2020	51.6	21.5	2.9	14.2	12.7	0.3	0.0	0.0
2021	51.4	20.6	2.1	14.4	13.9	0.3	0.0	0.0
2022	46.0	18.8	1.8	11.8	12.9	0.8	0.0	0.0
2023	37.0	15.8	1.4	7.1	12.3	0.5	0.0	0.0
2024	30.8	14.4	0.5	5.3	9.9	0.6	0.0	0.0
2025	29.4	14.6	0.0	4.5	10.1	0.2	0.0	0.0
2026	25.9	12.4	0.0	4.0	9.1	0.4	0.0	0.0
2027	19.7	10.8	0.0	3.6	5.2	0.0	0.0	0.0
2028	18.6	10.3	0.0	3.4	4.9	0.1	0.0	0.0
2029	19.3	9.9	0.0	3.0	6.5	0.0	0.0	0.0
2030	17.1	9.3	0.0	2.7	5.1	0.0	0.0	0.0
2031	15.4	9.2	0.0	2.3	4.0	0.0	0.0	0.0
2032	15.0	8.9	0.0	2.1	4.1	0.0	0.0	0.0
2033	14.3	8.8	0.0	1.8	3.7	0.0	0.0	0.0
2034	13.4	8.2	0.0	1.5	3.7	0.0	0.0	0.0
2035	13.9	8.0	0.0	1.4	3.4	1.2	0.0	0.0
2036	12.1	6.8	0.0	1.3	3.2	0.8	0.0	0.0
2037	12.5	7.0	0.0	1.3	3.1	1.0	0.0	0.0
2038	11.5	6.8	0.0	1.3	2.5	0.8	0.0	0.0
2039	10.5	6.8	0.0	1.2	1.2	1.3	0.0	0.0
2040	8.6	6.7	0.0	1.2	0.1	0.6	0.0	0.0
Total	**1210.7**	911.1	48.4	107.6	135.2	8.4	0.0	0.0

The Proponent provided upside and downside production profiles for the total development (Figure 4.3.4.2).

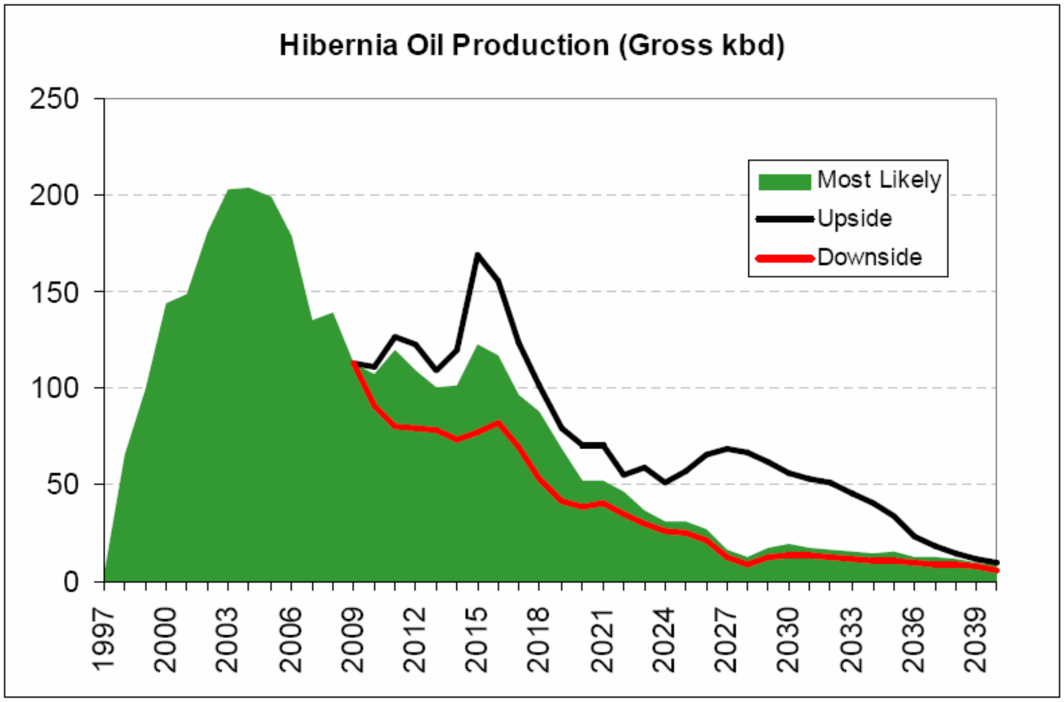


Figure 4.3.4.2: Hibernia Oil Production Forecast for Upside, Most Likely, and Downside Cases (Source: HMDC)

The Proponent's reservoir simulation model assumes 95% water cut or less than 1000 barrels per day oil production as the cut-off for zone or well abandonment. The Board's staff has determined that these abandonment criteria are reasonable; however, staff will continue to work with the Proponent to define the specific criteria for zone and well abandonment.

Under the Board's mandate, staff believe that it is important to maximize the use of the facility with maximizing the recovery of the resource. Staff will assess the abandonment of each well through its approval to abandon a well. This process ensures that maximum recovery of the resource is considered and waste of the resource is minimized.

Board staff will also consider whether wells intersect oil-bearing zones in secondary reservoirs and ensure that these zones are perforated and tested prior to well abandonment when appropriate.

4.3.5 Field Economic Life

In the Decision Report 97.01, the Proponent had a field economic cut-off of 31,500 barrels per day (5000 m^3 per day). This cut-off was based on 1994 estimates of capital and operating expenditures. This field economic cut-off was revised in the June 2009

DPA and lowered to 10,000 barrels per day (1590 m^3 per day) (Figure 4.3.5.1). This economic cut-off has been maintained in the current Application. Board staff agree that this is reasonable at this time.

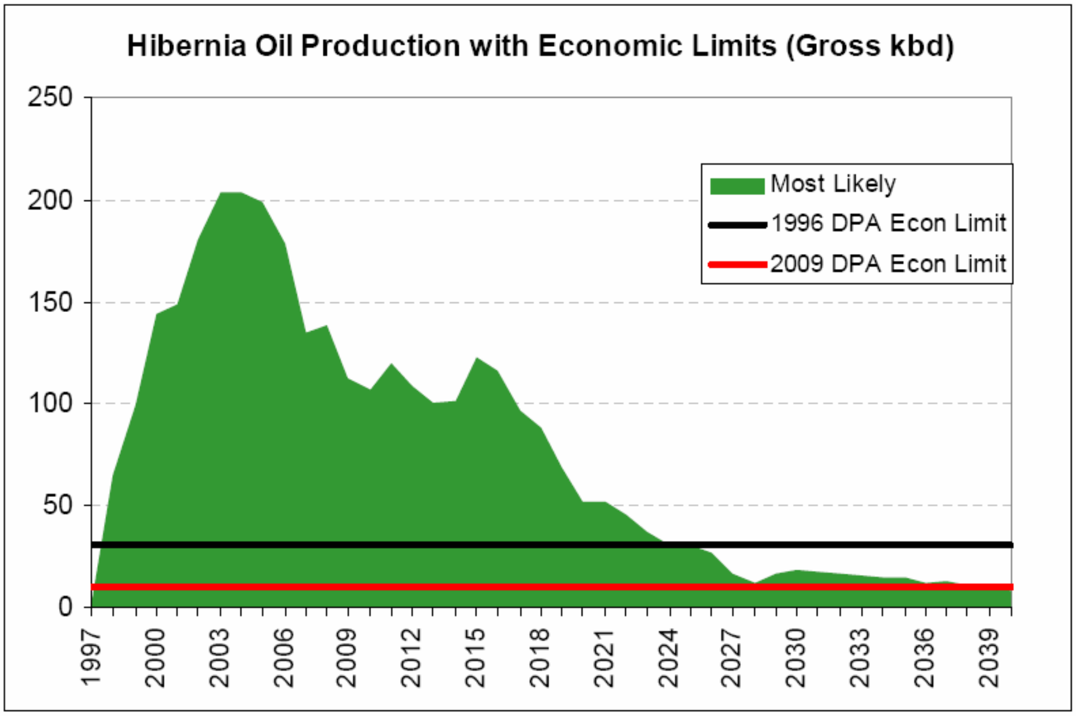


Figure 4.3.5.1: Hibernia Oil Production Forecast with Economic Limits (Thousands of Barrels per Day) (Source: HMDC)

4.3.6 Gas Utilization

In addition to oil production, the Hibernia facility is involved with the production and handling of gas from the Hibernia Field. Figure 4.3.6.1 shows the forecast of gas utilization from oil production for the field life. Since gas injection began in 2000, 90% of the gas produced has been re-injected into the reservoir for pressure maintenance and to optimize oil recovery in Hibernia gasflood fault blocks. Produced gas is also used as the primary fuel source for the platform, accounting for 6-8% of gas production on average. A certain amount of gas is flared to maintain a pilot flare for unplanned production upsets, which accounts for less than 1-2% of the total gas volume produced. The Proponent has reducing the annual amount flared for the last three years, staying well below the regulated annual limit. Starting in 2012, a portion of the gas produced will be used for gas lift as well, as seen in Figure 4.3.6.1.

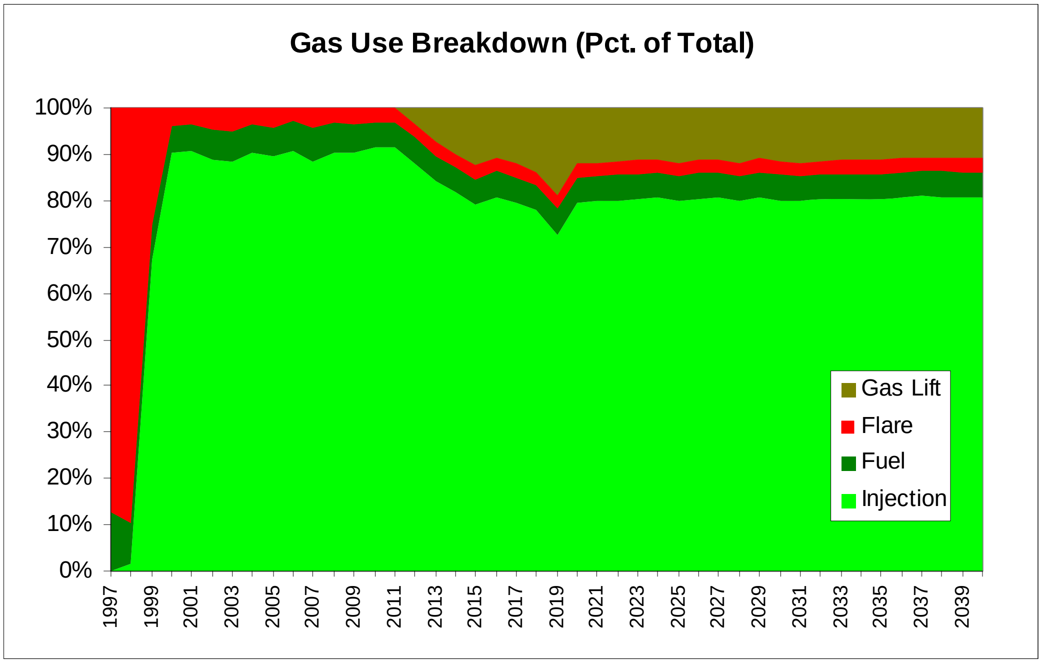


Figure 4.3.6.1: Hibernia Full Field Gas Utilization Breakdown (Source: HMDC)

The Proponent has been able to achieve high recovery from the gasflood area by maintaining minimum reservoir pressure of at least 1000 kPa above bubble point. Because the Hibernia Field's life has now been extended to 2041, the amount of gas that will be required to support voidage replacement in the gasflood area may become challenging.

The Proponent has proposed several options in order to maintain gas compression capacity in the gasflood area. These include:

1. Produce gas zones in the Hibernia or other reservoirs to provide a source of gas to maintain gasflood pressure. The first application of this option was production of the gas cap in the Q Block from B Pool Zone 2 Upper in 2008.

2. Overproduce isolated, low-volume, high gas-oil ratio areas of the existing gasflood to allow the pressure in the remainder of the gasflood to be maintained, such as I Block.

3. If it can be demonstrated that there is no detriment to ultimate recovery, then measured decline in pressure may be allowed over the entire gasflood region.

Although the Proponent's compositional study shows that the potential impact of pressure decline on ultimate recovery is nil, staff feel it is necessary that the Proponent should meet with Board staff to discuss each of the above options prior to any implementation.

Another pressure maintenance mechanism under consideration is water-alternating-gas (WAG) injection. The Proponent has submitted a document entitled *Study of Recovery by Double Displacement Process (DDP) for the R Fault Block in Hibernia Field, Newfoundland and Labrador, Canada* as a Part II document supporting this Application. This study indicates that WAG injection could lead to additional oil recovery, primarily through vaporization. However, the effectiveness of vaporization in a watered-out zone is uncertain. It concludes that WAG may be more appropriate later in the life of the field. Near-term limitations on slot requirements and gas availability make WAG injection unfeasible at this time. Currently, produced gas is most effectively used for re-injection in the gasflood region.

Board staff are encouraged by the Proponent's efforts to examine the potential for additional oil recovery using newer technologies and processes. The progress of this development scheme will be reviewed in the future with the annual review of the Proponent's Resource Management Plan.

4.3.7 Deferred Developments

In this Application, the Proponent highlights only gas commercialization as a deferred development opportunity.

Reserves estimates for natural gas liquids (NGL's) that were previously included as deferred development have been included in the individual pool reserves estimates in the Application.

The Board estimates natural gas liquid resources to range from 133 million barrels (21.1 million Sm^3) to 262 million barrels (41.7 million Sm^3). The Board's staff notes that the Proponent provided for the recovery of 43.8 million barrels of NGL's in its oil reserves estimates. However, there is potential to extract additional natural gas liquids from the Hibernia Field, in excess of that estimated by the Proponent. Data collected from the Hibernia reservoir gas cap suggest that the gas is very rich in liquids. To date, the Board has placed operating pressure limitations on the gasflood region to ensure that the drop-out of these liquids does not occur in the reservoir, and to preserve the opportunity to implement exploitation schemes to recover these resources in the future.

The Board's staff believes that potential exists to implement a gas cycling scheme to exploit the liquid resources. However, several reservoir and facilities issues need to be studied to assess the feasibility of applying such a scheme. The progress of NGL development will be assessed in the future during the annual review of the Proponent's Resource Management Plan.

The Proponent's updated estimates for original gas in place and gas reserves for the Hibernia Field are listed in Table 4.3.7.1.

Table 4.3.7.1: Hibernia Field Original Gas In Place and Recovery Range (Source: HMDC)

Reservoir	Original Gas In Place (GCF)			Gas EUR (GCF)		
	Gas Cap	Solution	Total	Gas Cap	Solution	Total
Hibernia B Pool	466	1970	2436	350	813	1163
Hibernia AA Blocks (B Pool)	0	119	119	0	40	40
Hibernia South Unit (B Pool)	0	139	139	0	47	47
Ben-Nevis Avalon	0	781	781	0	158	158
Hibernia A Pool	111	179	290	28	7	35
Catalina	89	65	154	4	2	6
Cape Island	0	5	5	0	0	0
Total	666	3258	3924	382	1067	1449

The Board's 2006 Hibernia recoverable reserves estimate lists the potential recoverable gas resources at the Hibernia Field as ranging from 953 billon standard cubic feet (26.9 billion m^3) to 2669 billon standard cubic feet (75.2 billion m^3), with a most likely estimate of 1796 billon standard cubic feet (50.6 billon m^3). Staff feels that the Proponent's estimate for total gas reserves is reasonable.

While the gas resource is currently used for fuel and for reservoir pressure support to exploit the oil reserves, it will eventually be available for production. Future exploitation of the gas resources may also extend the economic life of the Hibernia Field, permitting additional oil to be recovered. The Proponent conducted a preliminary review of gas commercialization in the Application. The timing of gas availability at the Hibernia Field for commercial purposes is dependent on the gas requirements for the exploitation of the oil reserves, and the natural gas liquids resources. According to the Proponent, Hibernia could support gas sales of 200-300 million standard cubic feet per day starting after 2020, in order to ensure that optimized reservoir oil exploitation occurs (Figure 4.3.7.1).

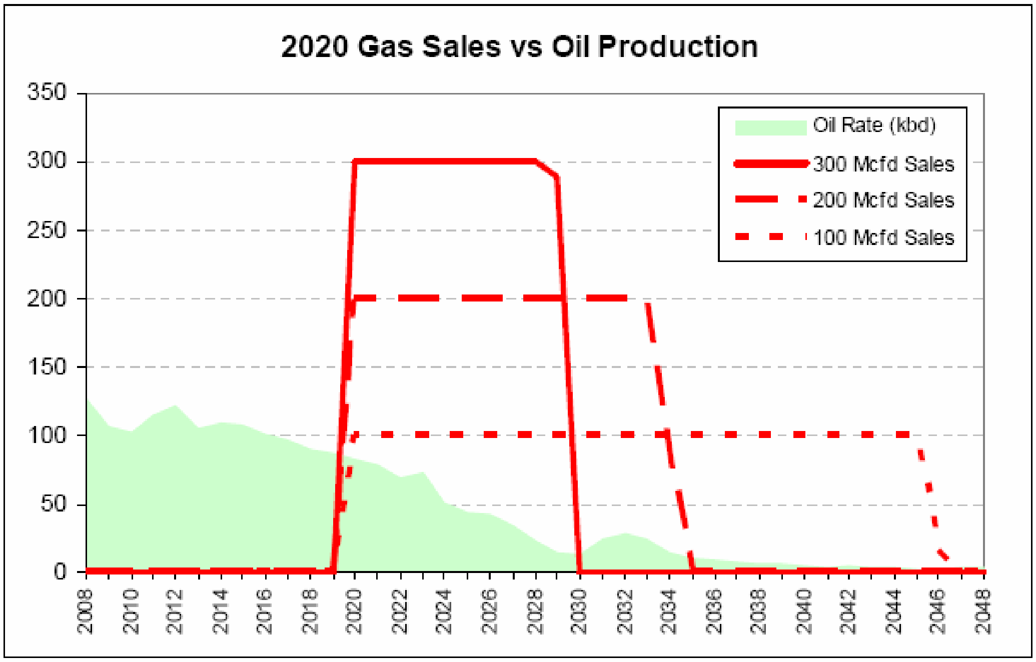


Figure 4.3.7.1: Possible 2020 Gas Sales vs. Oil Production (Source: HMDC)

Board staff agrees with the Proponent that further technical assessment will be required to define the viability and timing of gas commercialization. The progress of the Proponent's gas commercialization plans will be assessed in the review of the Proponent's Annual Resource Management Plan.

The Board's staff recognizes that oil has been encountered in other reservoirs within the Hibernia Field, specifically the Whiterose and Jeanne d'Arc Formations. The Proponent has already acquired data from drilling to aid in characterizing these potential reservoirs, and plans future geologic studies to further assess their development potential. It is likely that some of these potential reservoirs will be exploited in the future, adding to the Hibernia Field reserves. The Board expects that the Proponent will continue to study these resources and will review the progress of this study in the Annual Resource Management Plan.

4.3.8 Facilities

The Hibernia facilities are currently fully utilized for oil production. Consequently, opportunities for deferred development must be considered in this context. This circumstance is not unusual for production facilities.

The Proponent has assessed potential opportunities for de-bottlenecking of the facilities in *Hibernia Debottlenecking and Expansion Report*, submitted as a Part II supplemental document to this Application. This development planning study evaluated facility expansion options and investigated the potential to add drill slots to the Hibernia Platform. The Proponent has concluded that the limited uplift benefit did not justify the cost of facility upgrades and the facility will allow for full exploitation of the resources.

In terms of metering and production accounting of HSE unit, the Proponent will provide a separate application in accordance with the flow system, flow calculation procedure and flow allocation procedure regulations

4.4 CONCLUSIONS AND RECOMMENDATIONS:

Full Field Exploitation

- The Proponent has proposed in the Application to develop the HSE Unit using ten wells (five oil producers drilled from the Hibernia Platform and five subsea water injectors). Development of the HSE Unit will not negatively impact the development of Hibernia B Pool, AA Blocks, Ben Nevis-Avalon reservoir or A Pool. Board staff are satisfied that the HSE Unit development strategy is appropriate for the Hibernia Field at this time.

    - **Board staff recommend that the development of the HSE Unit be approved as described in the Application.**

- The Proponent has proposed in the Application to develop the Catalina and Cape Island Members, and has addressed the development of these resources in the context of the full Hibernia Field; however, it acknowledges that further evaluation is required. Board staff concur with this assessment.

    - **Board staff recommend that the Proponent's proposed approach for the development of the Catalina and Cape Island Members be approved and that production from these members should be addressed on a well-by-well basis. The progress of the development of these resources will be reviewed and updated in the Proponent's Annual Resource Management Plan.**

- Several areas for future development have been highlighted in the Board's analysis including NGL resources, gas commercialization and the Whiterose and Jeanne d'Arc reservoirs.

    - **Board staff recommend that any other future developments within the Hibernia Field will be reviewed and updated in the Proponent's Annual Resource Management Plan. The development of these resources will require a Development Plan Amendment.**

The additional conclusions below are based on the individual assessment of each of the reservoirs/pools in the Hibernia Field that impact the decision regarding this Application. The appendices include a more detailed discussion of these conclusions, and additional conclusions for the remaining pools are presented in individual appendices.

HSE Unit

- The structural model, reservoir quality, and position of oil-water contacts for the HSE Unit are the primary sources of uncertainty leading to a range of possibilities in estimating volumes for this area of the field.
- The Proponent's most likely estimates of STOOIP volumes [260.8 million barrels (41.5 million m^3) of oil and 139.1 billion cubic feet (3.9 billion m^3) of gas] based on an oil-water contact of 4816 m TVDss are considered possible.
- The Proponent's depletion strategy, consisting of ten wells (five oil producers drilled from the Hibernia Platform and five subsea water injectors), is reasonable.
- The Proponent's range of estimated ultimate recovery from 68.3 million barrels to 169.3 million barrels, with 107.6 million barrels being the most likely, is reasonable given the geological/geophysical uncertainty that exists within the HSE Unit.

Hibernia B Pool

- Analysis of production from B Pool indicates that the Board's latest reserves estimate for the Hibernia Field, conducted in 2006, needs to be updated.
    - **Board staff recommends that an additional 150.8 million barrels of oil reserves should be added to the Hibernia B Pool reserves, increasing the Hibernia Field oil reserves estimate to 1395 million barrels from 1244 million barrels.**

5.0 Operations and Safety

The safety review of the Application included an assessment of the Proponent's conceptual plans to excavate a glory hole, install subsea templates, tie-in water injection manifolds and drill subsea water injection wells utilizing a semi-submersible drilling installation for the Hibernia South Extension. In addition, the safety review of the Application included an assessment of the Proponent's plans for the installation of a gas lift system for existing and future wells. The drilling of wells from the Hibernia Platform into the proposed new blocks and the subsequent production or workovers of these wells were not reviewed as there are no significant impacts introduced to equipment, processes or training.

The installation of subsea templates was discussed briefly in the 1986 and 1990 Hibernia Development Plan submissions and is the subject of Condition 9 of the C-NLOPB's 86.01 Decision Report, which required 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." The Proponent's approach to subsea development is an acceptable methodology, which has been successfully implemented for both the Terra Nova and White Rose Field Developments. The concept of the installation of a gas lift system was previously mentioned in the 1990 Hibernia Development Plan submission, although it was not deemed necessary in the original Hibernia project design.

The production of hydrocarbons from subsea templates is discussed briefly in the Application; however, as sufficient information has not been provided in the Application it is not part of the scope of this review of this Development Plan submission. The Proponent has also confirmed that production of hydrocarbons from subsea templates is not anticipated.

5.1 Conceptual Plans

The following provides an overview of the conceptual plans for each element of the project:

5.1.1 Excavation of Glory Hole, Installation of Subsea Templates and Tie-in of Water Injection Manifolds

The Hibernia South Unit is proposed to be initially developed with the drilling of production wells from the Hibernia Platform.

The Proponent has committed to undertaking geophysical surveys for the pipeline routes and glory hole locations for subsea developments. The Proponent carried out the surveys in June and July 2010.

The Proponent has proposed that the glory hole will be located approximately 7 km southeast of the Hibernia GBS and will include manifold template(s) for six wells. It is proposed that the total depth of the glory hole will be 10 m below the seafloor and the minimum distance between the top of the subsea installation to the seafloor will be 3 m. The construction of the glory hole will use methods similar to those used previously on the Grand Banks. Well tie-ins and other installations may be performed using diving support vessels, mobile offshore drilling units, divers and/or remote operated vehicles.

The tie back will include stimulation lines and control umbilical, with weak links and a water injection pipeline. It is proposed that the water injection pipeline and umbilical will utilize two existing J-tubes within the Hibernia GBS. Rock dumping will be used to protect the pipeline and umbilical and additional dropped object protection may be installed. It is proposed that modifications required on the topsides will include the addition of:

- Subsea control equipment
- Construction of a new local electrical and instrumentation room (LEIR) to accommodate this equipment
- Methanol equipment to prevent hydrate formation in water injection well during periods of shutdown
- Replacement of current fire fighting foam with foam more suitable for methanol fires
- Automated sampling and meter systems for existing test separators
- HP water injection stimulation and booster pumps
- Additional flowlines to existing production, test and water injection manifolds
- Integration of new systems with existing control and safety systems and utility systems

The Proponent considers that the capacity of existing production facilities are considered to be adequate for current reservoir production profiles and other than the installation of a gas lift system, that no other major system additions outside the scope of the Development Plans are anticipated at this time. If modifications are to occur, the Proponent will use the existing management of change process described in the Hibernia Operational Plan. This process requires the involvement of the Certifying Authority. Additional details on the proposed project are provided in the Application and in the Concept Safety Analysis.

For well tie-ins and other installations may be performed using diving support vessels, mobile offshore drilling units, divers and/or remote operated vehicles.

Subsea construction and subsea installation activities involving the use of construction or diving vessels will require that the existing Work Authorization be updated or an application for new Work Authorization be submitted. The Proponent is required to submit revisions to existing work authorizations or to submit applications for new work authorizations for subsea construction and installation activities at least three months prior to commencement of these activities.

5.1.2 Subsea Drilling Program

The Proponent has proposed that a harsh weather semi-submersible mobile offshore drilling unit, suitably designed and rated for operation on the Grand Banks will be utilized to drill five subsea water injection wells from the glory hole. It is proposed that the subsea drilling program will occur from 2013 – 2015.

A description of drilling and completions are provided in the Application. Additional details regarding the station keeping and well control systems has been provided in the Proponents response on April 7, 2010 to the C-NLOPB's request for additional information in respect of the Application.

Subsea drilling activities involving the use of a mobile offshore drilling unit will require that the existing Work Authorization be updated or an application for a new Work Authorization be submitted. The Proponent is required to submit revisions to the existing work authorization or to submit an application for a new work authorizations for subsea drilling activities at least six months prior to commencement of these activities.

5.1.3 Subsea Workovers/Interventions

The Proponent has proposed to design the subsea wells to limit the need for intervention during the life of the field and has proposed to use vertical xmas trees to better facilitate workovers should they be required. Details and requirements for future workover/intervention capability should be specified in the Hibernia Operational Plan. If a mobile offshore drilling unit or light intervention vessel is required to carry out subsea workovers/interventions, it is required that the existing Work Authorization be updated or an application for new Work Authorization be submitted. The Proponent is required to submit revisions to the existing work authorization or to submit an application for a new work authorizations for subsea workover/intervention activities at least six months prior to commencement of these activities.

5.1.4 Installation of a Gas Lift System

The concept of the installation of a gas lift system was previously mentioned in the 1990 Hibernia Development Plan submission, although it was not deemed necessary in the original Hibernia project design. The installation of gas lift in future wells and retrofitting selected existing wells will help maximize the recovery of resources from the Hibernia field.

For the Proponent to utilize gas lift, modifications to the Hibernia Platform will include the following:

- Addition of a glycol dehydration and regeneration package
- Potential gas compressor modifications
- Addition of gas lift headers, east and west manifolds and flowlines to wells fitted with gas lift equipment
- East and West manifold structural decking extension
- Integration of new systems with existing control and safety systems and utility systems

Some modifications to the platform have already been performed. Some of this work was completed during the March 2009 planned facilities shutdown. In addition, to complete the installation, downhole gas lift equipment will be installed during well workovers. Additional details on the gas lift system and gas lift completion diagrams have been provided in the Application, in the Concept Safety Evaluation for the Gas Lift Project and Detailed Design Basis for the Gas Lift Project.

5.2 Concept Safety Analysis

As part of this Application, two updates to the Concept Safety Analysis were received and reviewed:

- Concept Safety Evaluation for the Hibernia South Extension Project
- Concept Safety Evaluation for the Gas Lift Project

These Concept Safety Evaluations have demonstrated that the Target Levels of Safety as described in Section 4.0 of the Hibernia Operational Plan have been achieved. The scope of the Concept Safety Evaluation for the Hibernia South Extension Project focuses on an assessment of the risk associated with modifications to the facility and the addition of subsea water injection and its effect on risk for the operations and maintenance of these systems. The scope of the Concept Safety Evaluation for the Gas Lift Project focuses on an assessment of the risk associated with modifications to the facility and to downhole well equipment for the installation of a gas lift system. The submitted Concept Safety Evaluations do not include a discussion of all phases of the project, i.e. they do not include a discussion of the effects on risk during the distinct phases of installation, hook-up, commissioning, subsea drilling, simultaneous construction and drilling/production, simultaneous drilling and production, simultaneous production and future subsea drilling and future workover/intervention activities, future workover/intervention activities and abandonment.

The Proponent has committed, however, to conducting specific hazard identification and risk assessments and implementing all actions necessary to manage the risks prior to commencing the following:

- Excavation of the glory hole
- Installation of subsea templates and tie-in of water injection manifolds
- Subsea drilling and subsequent well approvals
- Subsea workovers/interventions and subsequent well approvals
- Decommissioning and abandonment

All hazard identification and risk assessments will be carried out in accordance with the Proponent's project management system and hazard identification risk assessment system as described in Section 3 and Section 4 of the Hibernia Operational Plan. This includes conceptual design risk assessments, detailed design risk assessments, hazard identification (HAZID) sessions, hazard and operability (HAZOP) sessions, construction risk assessments and various other safety and loss control engineering assessments as the project progresses. The Proponent has committed that all recommendations from these assessments will be implemented prior to commencement of the above activities. At the time of application for an amendment to existing work authorization or at the time of application for a new work authorization for subsea construction, installation, drilling and/or workover/intervention activities, the Proponent is required to submit specific hazard identification and risk assessments conducted for those activities and describe how the hazards will be managed.

In addition, during construction, installation, hook-up and commissioning activities onboard the platform, there will be additional equipment installed, such as a winch and additional considerations regarding these activities, such as simultaneous construction and production and simultaneous construction and drilling, as well as, a number of other disruptions. The Proponent is required to submit specific hazard identification and risk assessments for the onboard construction activity and describe how the hazards will be managed.

The Concept Safety Evaluation for the Hibernia South Extension project has recommended the following:

- Prior to commissioning of the new plant, that an assessment is performed to quantify any expected changes in manning.
- A detailed explosion analysis is undertaken at the design stage in order to confirm that all equipment, including equipment added to the platform since 1999 and the equipment associated with the Gas Lift project and the Southern Extension, to confirm that potential explosion overpressures are not underestimated.
- Detailed studies will be required to confirm or refine some of the assumptions that have been made in the initial assessment.

The Concept Safety Evaluation for the Gas Lift project has recommended the following:

- The weight of the topsides should be reviewed in order to ensure that structural collapse as a result of overweight is not a potential hazard.

- Prior to commissioning of the new gas lift plant, that an assessment is performed to quantify any expected changes in manning.
- A detailed explosion analysis is undertaken at the detailed design stage once details of the additional wells and flowlines have been confirmed and other details are available.
- Detailed consequence modeling from additional release events be performed at the detailed design stage.
- During the detailed design stage, once the location of modified or new escape routes has been defined, that an evacuation and rescue study be performed and the risk assessment be revised accordingly.
- Detailed studies will be required to confirm or refine some of the assumptions that have been made in the initial assessment.

In addition, to the commitments to performing a fire and blast study and to identifying and conducting any additional studies during the detailed design phase, the Proponent has committed to updating the Quantitative Risk Assessment with the proposed design changes, and to include methanol hazards, increased probability of events from the addition of wells, and dropped objects. The Proponent has also committed to providing any new safety assessments and safety studies to the C-NLOPB for review and to updating Section 4 of the Hibernia Operational Plan to reflect the latest information as a result of its safety studies and assessments. During the detailed design phase, the Proponent is requested to keep Board staff informed of the detailed schedule for the project, including a schedule for any ongoing or future safety studies or safety assessments and to make new safety studies and safety assessments available to Board staff for review. The updated Quantitative Risk Assessment and Section 4 of the Hibernia Operational Plan is requested to be submitted to the C-NLOPB for review.

As part of the Application, the Proponent provided three safety-related studies:
- GBS Slot Additions – Technical Feasibility Assessment, 2007
- Hibernia Debottlenecking and Expansion Report, March 2008
- Hibernia Platform Service Life Extension, March 2008

A description of the purpose and results of each of these studies has been provided in the Application. The GBS Slot Additions – Technical Feasibility Assessment report identified that the drilling of additional slots in the GBS was not technically feasible, but identified that there is a significant presence of cuttings in the drill shafts, which pose additional hazards. Board staff have requested further explanation and evaluation of the additional hazards that may have been introduced as a result of the presence of cuttings in the drill shafts. The Proponent has been requested to provide plans for addressing additional hazards posed by the presence of cuttings in the drill shafts.

5.3 Design

The Proponent has committed in its Application to complying with existing Hibernia practices, standards and specifications originating from the original project and to conforming to the requirements of Canadian Federal and Provincial regulations and guidelines. In addition, the Proponent has committed to supplementing the above with current ExxonMobil Global Practices. Section 4 of the Hibernia Operational Plan also commits to designing the platform to internationally accepted design standards and to meeting the requirements of the Safety Design Philosophy. The Proponent has also specified fatigue, service life, cathodic protection and design sour service requirements in the Application. As part of the Application, the Proponent has submitted a list of design standards with respect to the subsea installation and the gas lift project.

In addition, Condition 5(ii) of C-NLOPB Decision Report 86.01 states “the design iceberg scour depth be determined by the Proponent and approved by the Board prior to the design of subsea well installations.” This condition is outstanding.

5.4 Certifying Authority Scope of Work

In accordance with the existing Scope of Work for Hibernia and the regulations, the Certifying Authority provides certification for all modifications, repairs and replacements and approves the inspection, monitoring, maintenance and weight control program onboard the Hibernia Platform. The Proponent has identified that the Certifying Authority will provide certification for all subsea and topsides tie-back project activities, and as a result, the Scope of Work will be updated to include these additional activities. The Proponent is required to ensure that the Certifying Authority provides an updated Scope of Work for approval by the Chief Safety Officer to address the additional scope and to incorporate the requirements imposed by the latest amendments to the Certificate of Fitness Regulations before commencement of subsea and topsides tie-back project activities.

With respect to diving vessels, mobile offshore drilling units and/or light intervention/workover vessels, either the existing Scope of Work or a new Scope of Work will have to be submitted with respect to these activities. With respect to Diving and Well Operations Installations, the Proponent is required to ensure that a Certifying Authority submit a new Scope of Work to the Board for approval by the Chief Safety Officer at least three months in advance of commencement of these activities with these installations.

5.5 Update and Submission of Other Documentation

5.5.1 Hibernia Operational Plan

The Hibernia Operational Plan, which serves as the Safety Plan, Environmental Protection Plan and Training Plan as per the Petroleum Drilling and Production Regulations, and the Operations Manual as per the Petroleum Installation Regulations, describes the hazard identification and risk assessment processes and design, mitigation and control measures in place to reduce risk to ALARP. It also includes a description of equipment, training and procedures and the management system in place to maintain risks to ALARP. During its review, the Proponent has proposed to update the following in the Hibernia Operational Plan:

- Relevant sections describing the hazard identification and risk assessment processes, safety studies and safety assessments, as well as, the associated results and mitigations required to maintain risk to ALARP
- Relevant sections regarding the additional platform and subsea equipment systems required for the subsea development will be added and other sections modified, as required, to reflect changes to other equipment systems, training and documentation.
- Relevant sections will be added regarding gas lift and other sections modified, as required, to reflect changes to equipment systems, training and documentation.
- Relevant sections will be updated to reflect changes to the platform safety exclusion zone.
- Relevant sections will be updated to include subsea drilling operations, subsea workover/intervention operations and subsea production operations in addition to current platform drilling, workover/intervention and production operations.

With respect to updates to the Hibernia Operational Plan:

- The Proponent is required to submit changes to the Hibernia Operational Plan for the gas lift project, at least three months prior to the start-up of gas lift operations from the Hibernia Platform.
- The Proponent is required to submit changes to the Hibernia Operational Plan, at the time of each application for amendment to the existing work authorization to include additional scope for subsea drilling activities. In addition, rig specific safety cases will be required to be submitted at this time.
- The Proponent is required to submit changes to the Hibernia Operational Plan, at least three months prior to start-up of subsea water injection from the Hibernia Platform.
- The Proponent is required to submit changes to the Hibernia Operational Plan, at the time of each application for amendment to the existing work authorization to include additional scope for subsea workover/intervention activities.

During these projects, the general arrangement drawings, fire and lifesaving plans and hazardous area drawings for the Hibernia Platform will be updated. The Proponent is required to submit the updated general arrangement drawings, fire and lifesaving plans and hazardous area drawings for the Hibernia Platform at the same time of submission of changes to the Hibernia Operational Plan.

5.5.2 Project-Specific Safety Plans

For construction and installation programs, the Proponent has committed to submitting project-specific Safety Plans and appropriate Bridging documents for each program associated with the installation of subsea facilities in the Hibernia field. Although it is not anticipated, it is possible that the Proponent may submit project-specific Safety Plans for subsea drilling or workover/intervention activities. It is expected the project specific safety plans will identify and address all hazards, specify the management system and describe the equipment, training and procedures that will be applied for the duration of the program. The Proponent is required to submit project-specific safety plans and bridging documents at the time of application for amendment to the existing work authorization or at the time of application for a new work authorization for subsea construction and installation activities. In the event that the Proponent decides to submit separate project-specific safety plans for subsea drilling or workover/intervention activities instead of submitting updates to the Hibernia Operational Plan then these documents are required to be submitted at the time of application for work authorization.

5.5.3 Hibernia Training Plan

As noted above, the Hibernia Training Plan has been incorporated into the Hibernia Operational Plan. The Proponent has committed to reviewing the qualifications, training and competency assurance requirements for various roles for the addition of future subsea facilities and to making appropriate updates to the Hibernia Operational Plan. Additional commitments were also in the Proponents response on April 7, 2010 to the C-NLOPB's request for additional information for the Application.

Subsea drilling, production and workover operations are different from current drilling, production and workover activities onboard the platform. The addition of subsea operations pose new hazards that must be considered in the qualifications, training and competency assurance requirements for both onshore and offshore personnel for both the relatively short-term subsea drilling program and in the long term, for production and future workovers from the Hibernia Platform. It is expected that during its reviews the Proponent will consider all these aspects and incorporate changes into its training program. The Proponent is requested to provide a description of changes to the organization, manning levels and associated qualifications, training and competency assurance requirements that will be in place for subsea drilling, production and workover activities for both onshore and offshore personnel for the subsea drilling program, for long-term production and future workovers. This information is to be provided at the time of each application for amendment to the existing work authorization to include additional scope for subsea drilling activities.

With respect to the gas lift project, the Proponent is required to provide a description of changes to manning levels and associated qualifications, training and competency assurance requirements for the gas lift project, at least three months prior to the start-up of gas lift operations from the Hibernia Platform.

5.5.4 Operation and Maintenance Manuals

With both the gas lift project and the subsea development will be the requirement to maintain and operate additional topsides and subsea equipment. The Proponent requires accurate, up-to-date and risk classified Operating and Maintenance procedures and Operation Systems Manuals. The Proponent has committed to expanding and updating the existing suite of Operations and Maintenance procedures and Operation Systems Manuals onboard the Hibernia Platform and ensuring that personnel competencies are assessed against the procedures to ensure they have the knowledge and skills to operate the facilities in a safe and effective manner. The Proponent has committed to ensuring that operations and maintenance personnel provide input during early planning and development of operating and maintenance procedures and that maintenance procedure will be developed to achieve required system reliability and availability. Any changes to the maintenance, inspection and testing programs will also require approval by the Certifying Authority.

The Hibernia Operational Plan as described above will be updated to reflect changes from the addition or modification of these procedures from both the gas lift project and for subsea water injection. The Proponent has committed to updating the above operations and maintenance procedures prior to start-up of the gas lift project and prior to start-up of subsea water injection.

The Proponent has also committed to conducting risk assessments prior to start-up of subsea drilling and subsea workover and/or intervention activities. Mitigations deemed necessary to manage the risk associated with specific operations shall be incorporated into necessary operational procedures, equipment specifications, and personnel requirements. The Proponent has committed that Operations identified as requiring mitigations shall not be initiated until all follow-up actions have been closed or mitigations established. This information was requested to be provided in discussions above.

During this project, there will be several simultaneous operations ongoing at the same time, which is not discussed in the Application or in the Concept Safety Evaluations. There will be additional hazards introduced by simultaneous construction, hookup, installation and commissioning with drilling/production activities, simultaneous subsea drilling and production activities, and finally, simultaneous production and future subsea drilling and future workover/intervention activities, which will need special consideration. The Proponent is required to update and submit its Simultaneous Activities Guidelines prior to the start of construction onboard the Hibernia Platform.

5.5.5 Emergency Response Plans

Hibernia's response to emergencies both onshore and offshore is specified in the Emergency Response Plan. The Emergency Response Plan outlines the specific emergency response procedures in place for dealing with major hazards and other emergencies as detailed in the Hibernia Operational Plan. The Proponent has committed to updating the Emergency Response Plans to include specific risks for subsea templates and subsea wells and to incorporate other risks as identified during the design phase. In addition, the Proponent has committed to undertaking a complete review of all contingency plans.

With respect to updates to contingency plans:

- The Proponent is required to submit changes to the Emergency Response Plan, at the time of each application for amendment to the existing work authorization to include additional scope for subsea drilling activities and for subsea water injection.
- The Proponent is required to submit changes to the Emergency Response Plan or to submit Project Specific Emergency Response Plans at the time of application for amendment to the existing work authorization or at the time of application for a new work authorization for subsea construction and installation activities.
- The Proponent is required to submit changes to the Emergency Response Plan, at the time of each application for amendment to the existing work authorization to include additional scope for subsea workover/intervention activities.

5.5.6 Ice Management

The Ice Management Plan contains tools to track, measure and execute deflection actions for icebergs. The Proponent has committed to updating its Ice Management Plan to include any subsea development and to incorporate other risks as identified during the design phase. In addition, the Proponent has committed to undertaking a complete review of all contingency plans. It is not anticipated that construction and installation will occur during the ice season. The Proponent is required to submit changes to the Ice Management Plan, at the time of each application for amendment to the existing work authorization to include additional scope for subsea drilling activities, subsea workover/intervention activities and for subsea water injection.

5.5.7 Logistics

The Proponent has committed to conducting a review of its support vessel configuration with the addition of the subsea development and addition of construction and installation vessels and subsea drilling and future workover/intervention activities. The support vessel configuration was approved previously under Condition 3(i) of C-NLOPB Decision Report 90.01. The Proponent is required to submit an updated support vessel configuration for its support fleet, during the detailed design stage. As part of this review, the Proponent is requested to review the latest requirements for the functional specifications and performance of support craft as outlined in the Drilling and Production Guidelines and the requirements as outlined in the Escape, Evacuation and Rescue Performance Based Standard. The Proponent will be requested to demonstrate the performance of their rescue capability.

5.5.8 Security Plans

The Proponent has stated that existing HMDC security plans and programs will apply to the project and that all vessels and mobile offshore drilling rigs engaged in the project will be expected to comply with applicable international and national codes or standards.

5.6 Future Considerations

5.6.1 Design Life

As discussed in the Application, the development of Hibernia AA Block and the Hibernia South Extension Unit will extend the Facility Life from 2027 to 2036. The Proponent has also submitted a report, entitled the Hibernia Platform Service Life Extension, March 2008. This report discusses several key issues associated with a design life extension, however is not complete with respect to all the issues which need to be considered as part of a facility life extension. As previously communicated in the C-NLOPB Decision Report 2009.10 Hibernia Development Plan Application, the facility life of the Hibernia Platform has not been approved beyond 2027. As requested in the previous Application, the Proponent will be required to submit the results of such an analysis to the Chief safety Officer for consideration before the end of 2024.

5.6.2 Decommissioning and Abandonment of Subsea Facilities

Condition 10 of C-NLOPB Decision Report 86.01 stated that “design provisions be made so that upon termination of production, subsea facilities and GBS are capable of being removed and the area returned to a fishable condition.” This condition was satisfied after the Proponent conducted a number of studies to develop a procedure for the removal of the GBS, which was reviewed and accepted by the Certifying Authority. The Proponent also submitted information acceptable to the Board regarding the removal of subsea crude loading facilities at this time. The Proponent has committed in this Application to decommissioning and abandonment of the existing platform and any subsea development will be in accordance with common industry practices and subject to the approval of the C-NLOPB. The Proponent is required to submit plans for decommissioning and abandonment of the proposed subsea development for approval by the C-NLOPB and the Certifying Authority before the commencement of this activity.

5.7 Conclusions and Recommendations

No safety concerns were identified which would preclude Staff from recommending approval of the Application. Activities in connection with this Application can be managed in accordance with established safety processes and procedures. All public comments received on this Application have been reviewed and have either been captured in the above analysis or will be addressed during the course of our review of applications for amendment to existing work authorizations or application for new work authorizations.

6.0 GLOSSARY

bbls (Barrels)
1 bbl = 0.15898 m3

BNA
Ben Nevis and Avalon

BOARD
The Canada-Newfoundland and Labrador 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-NLOPB
Canada-Newfoundland and Labrador Offshore Petroleum Board

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

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.

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

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

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.

m3
1 m3 = 6.2898 bbls

mTVDss

Meters true vertical depth subsea.

Member
A rock stratigraphic unit that is distinctive but local part of a formation.

Petrel
Trademark of Schlumberger product group geologic modelling software.

Petrophysics
The science and application of measuring borehole rock properties and establishing relationships between these properties.

Pool
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.

Reserves
The 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. Hibernia, Terra Nova, and Whiterose are classified as reserves.

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.

STOOIP
Stock tank original oil in place

7.0 LISTS OF APPENDICES

Appendix A

Hibernia Southern Extension Unit

A.1 Hibernia Southern Extension Unit – Hibernia B Pool

The Hibernia Southern Extension (HSE) Unit is located in the southern section of the Hibernia field and is contained within PL1001, PL1005 and EL1093. According to the Proponent's application, the HSE Unit is comprised of the KK, GG1, GG2, LL and MM Blocks. Previously, the HSE was also considered to include the AA Block and the NN Block. Development of the AA Block was addressed in the Hibernia June 2009 DPA and is currently underway. Development of the NN Block has not been addressed by the proponent and will be discussed later in this report. Also, the Ben Nevis-Avalon (BNA) reservoir in the HSE Unit area will be addressed in the separate review of the BNA reservoir (Appendix E).

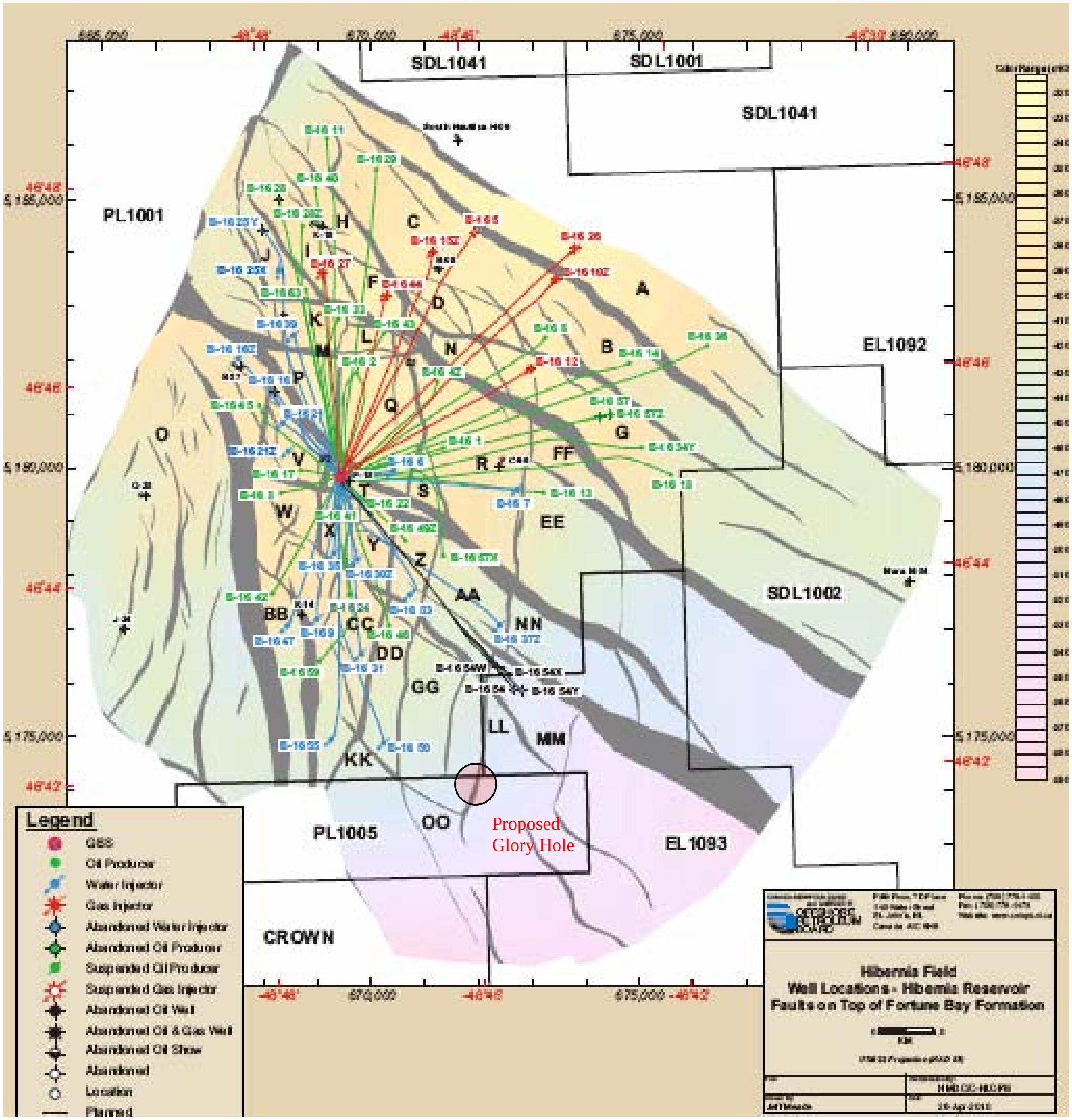


Figure A.1: Hibernia Field with proposed HSE Unit Glory Hole Location. (Source: C-NLOPB)

A.2 Geological/Geophysical Model Review

The Board's staff reviewed the Proponent's Petrel geological model for the HSE Unit. While the lithologies and reservoir connectivity are anticipated by the Proponent to be similar to what was encountered in other development wells in the area, there are some expected differences in facies distribution and reservoir characteristics toward the southeastern, structurally deeper part of the reservoir. The Proponent expects the Hibernia B Pool reservoir to exhibit degradation of porosity and permeability with increasing burial depth, and has mapped a possible facies change to the southeast that would result in an increase in shale volume and a decrease in overall reservoir quality and thickness. Consequently, the reservoir in the HSE Unit is anticipated to be poorer than at the crest of the field, and to decrease significantly in quality toward the southeast. Board staff acknowledge that this interpretation is within the realm of possibility, and will be confirmed by drilling results.

The Proponent has revised its interpretation of seismic data since 2009, and this has led to changes in the structural framework for the HSE Unit. The current submission is based on a model wherein the Hibernia reservoir thins to the southeast. This is a significant change from previous modeling by the Board and the Proponent, which assumed constant thickness of the reservoir units. This new interpretation results in a lower bulk reservoir volume, and consequently lower hydrocarbon volumes than previously estimated in 2009. Board staff acknowledge that this revised interpretation is possible, but have not incorporated this revised interpretation into Board models and volume estimates. The validity of the Proponent's seismic reinterpretation is expected to be confirmed upon drilling of development wells in the HSE Unit.

The Proponent has suggested three possible cases for fluid contacts, based on well log and pressure data from existing wells in the southern part of the field, structural mapping and known fluid contacts in nearby developed blocks. The Board's staff acknowledges that these three scenarios are reasonable interpretations, and agrees that the best case of fill to a structural spill point is the deepest likely expectation for an oil-water contact. A map highlighting the three possible scenarios for fluid contacts is highlighted in Figure A.2.

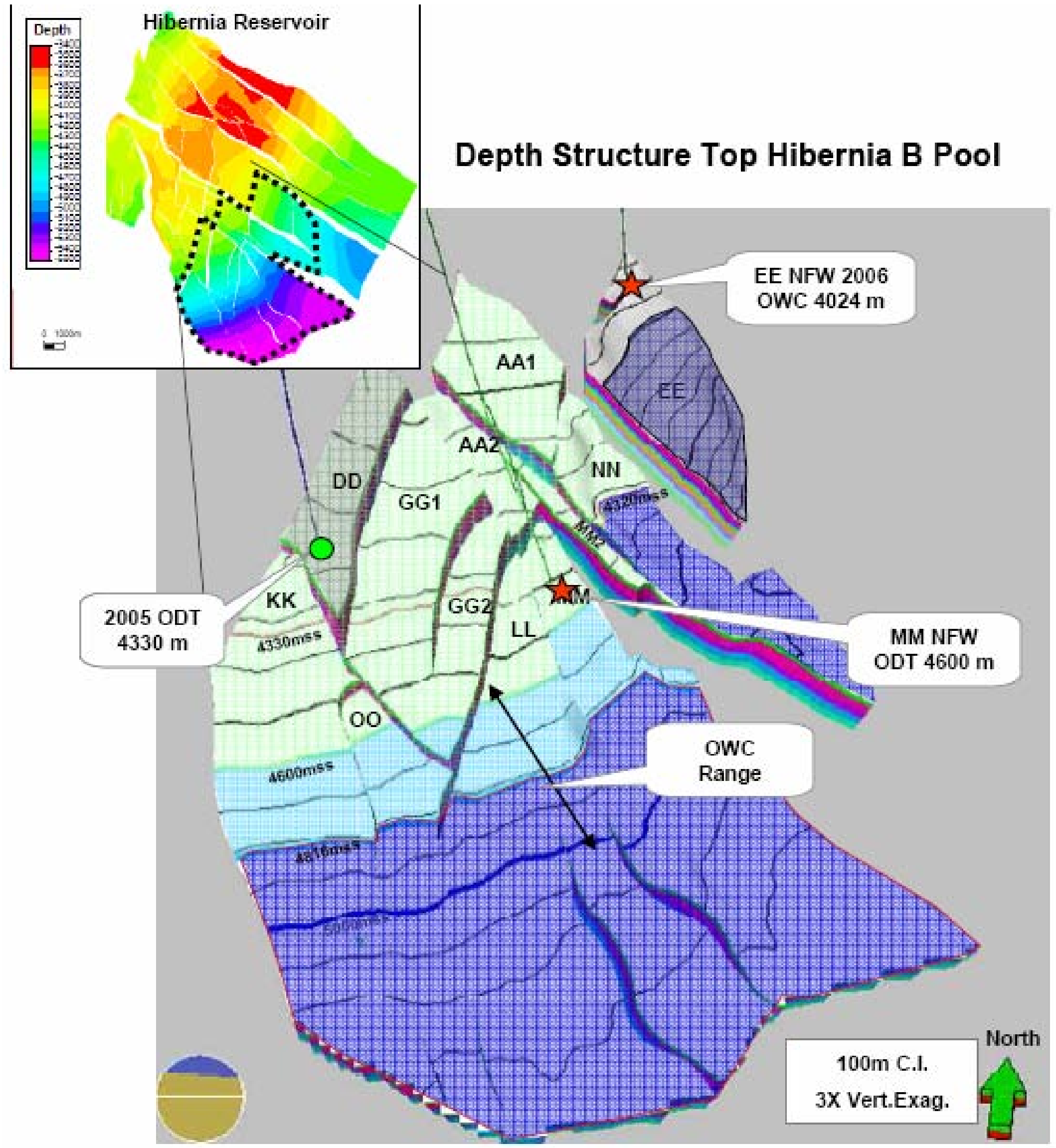


Figure A.2: Map of HSE Unit, Outlining the Three Possible Oil-Water Contact Scenarios. (Source: HMDC)

As the HSE is an outlying area of the field, Board staff expect that the Proponent will acquire additional core in keeping with its coring strategy as outlined in the *Hibernia Field Data Acquisition Program Update for 2007-2010*. The water injector wells, in particular, offer excellent opportunities to core Hibernia and BNA reservoir intervals in down-dip locations that will provide valuable information on facies distribution and reservoir quality. Coring requirements for individual wells will be assessed through the Approval to Drill a Well process.

A.3 STOOIP and Reserves Estimates

In late 2009 the Proponent made significant changes to its geological model for the HSE Unit, as previously discussed. These changes resulted in a revision to the reserves estimates for the HSE Unit.

Table A.1: Proponent's 2006, 2010 and C-NLOPB's 2006 Hibernia HSE Unit STOOIP and Reserves Estimate Summary (Field Units). (Source: Modified HMDC/C-NLOPB)

	HMDC 2006		HMDC 2010		C-NLOPB 2006	
Block	**STOOIP**	**EUR**	**STOOIP**	**EUR**	**STOOIP**	**EUR**
GG1	153	73	86.3	43.3	149.5	70.0
GG2			31.9	14.5		
KK	58	26	67.3	28.1	83.5	37.6
LL	42	19	32.7	13.6	46.6	21.0
MM	17	8	18.9	8.1	54.0	20.5
MM2			8.9	0		
OO	0	0	6.6	0	11.0	4.9
NN	0	0	8.2	0	33.8	13.0
Total	**270**	**126**	**260.8**	**107.6**	**378.4**	**167**

As discussed in the preceding section, Board staff acknowledge that the revised geological model for the HSE Unit, though conservative, is within the realm of possibility considering the limited data available. However, the Board's current model for the HSE Unit is also reasonable; therefore, no changes are planned to the Board's 2006 reserve estimate of 167 million barrels (MMbbls). Board staff feel that there is insufficient data to rule out either case, and drilling in the HSE Unit will resolve uncertainty with respect to the oil-water contact and reservoir quality.

Gas reserves are not included in this HSE Unit assessment, but gas production from the Hibernia field is discussed as a concept later under Deferred Development. Gas in place in the HSE Unit is expected to exist entirely in solution and is anticipated to be 139.1 billion cubic feet (GCF), as indicated in Table A.2.

Table A.2: Proponent's HSE Unit B Pool In-Place Volumes (Field Units). (Source: HMDC)

C-NLOPB Sub-Pool	Block	Oil STOOIP (MB)	GIP Free Gas (GCF)	GIP Solution (GCF)	Total GIP (GCF)
Developed Blocks					
Potential Future Blocks, included in Drill Schedule					
B2	GG1	86.3	0.0	57.7	57.7
B2	KK	67.3	0.0	31.1	31.1
B2	LL	32.7	0.0	13.5	13.5
B2	GG2	31.9	0.0	16.2	16.2
B2	MM	18.9	0.0	7.7	7.7
Other Blocks in the Hibernia South Unit (Volume assumes best estimate OWC)					
B2	OO	6.6	0.0	2.5	2.5
B2	MM2	8.9	0.0	5.0	5.0
B2	NN	8.2	0.0	5.4	5.4
Subtotal: Developed		**0.0**	**0.0**	**0.0**	**0.0**
Subtotal: Developed in Schedule		**237.1**	**0.0**	**126.2**	**126.2**
Subtotal: Other Blocks		**23.7**	**0.0**	**12.9**	**12.9**
Total South Unit		**260.8**	**0.0**	**139.1**	**139.1**

Note that gas is not part of the Unit.

The following table presents the Proponent's high, most likely and low case reserves estimates for the HSE Unit.

Table A.3: Proponent's HSE Unit B Pool High, Most Likely and Low Reserve Cases. (Field Units) (Source: HMDC)

C-NLOPB Sub-Pool	Block	Upside Recoverable (MB)	Upside Recoverable (Mm3)	Most Likely Recoverable (MB)	Most Likely Recoverable (Mm3)	Downside Recoverable (MB)	Downside Recoverable (Mm3)
Developed Blocks							
Potential Future Blocks, included in Drill Schedule							
B2	GG1	65.1	10.3	43.3	6.9	25.2	4.0
B2	KK	45.4	7.2	28.1	4.5	18.8	3.0
B2	LL	23.3	3.7	13.6	2.2	7.3	1.2
B2	GG2	22.0	3.5	14.5	2.3	12.5	2.0
B2	MM	13.5	2.1	8.1	1.3	4.4	0.7
Other Blocks in the Hibernia South Unit (Volume assumes best estimate OWC)							
B2	OO						
B2	MM2						
B2	NN						
Subtotal: Developed		0.0	0.0	0.0	0.0	0.0	0.0
Subtotal: Developed in Schedule		169.3	26.9	107.6	17.1	68.3	10.9
Subtotal: Other Blocks							
Total South Unit		169.3	26.9	107.6	17.1	68.3	10.9

A.4 Development Strategy

The Board's staff reviewed the Proponent's proposed depletion plan for the HSE Unit fault blocks (Figure A.3).

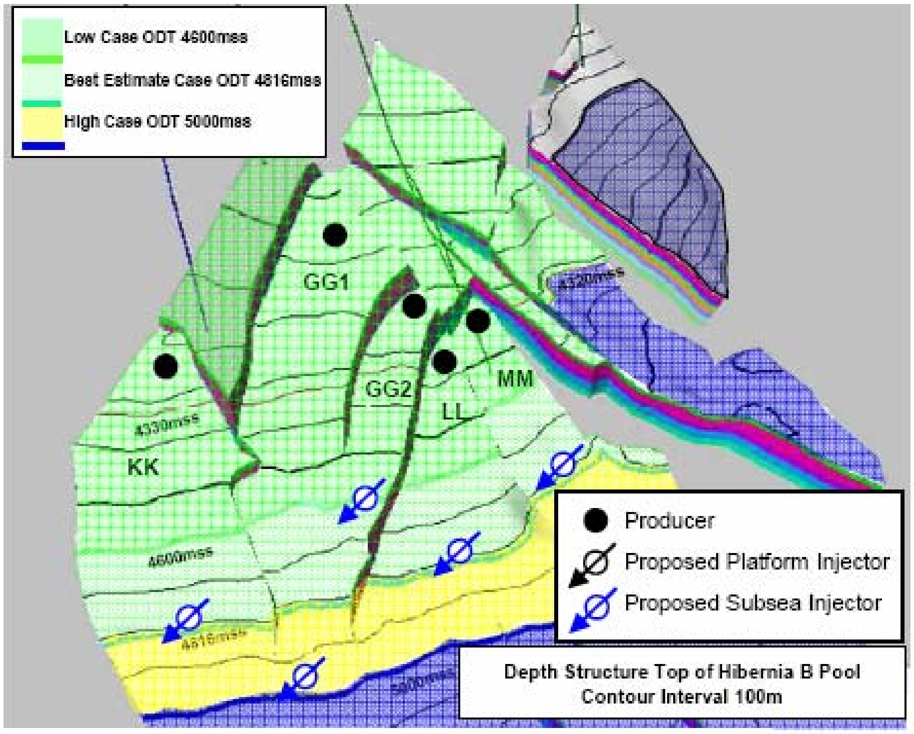


Figure A.3: Proposed HSE Unit Development Well Locations. (Source: HMDC)

The Proponent intends to develop the HSE Unit through waterflood, which is currently used in a large part of the existing Hibernia B Pool development. Board staff concur that waterflood is the optimal depletion strategy to maximize reserves from the HSE Unit. The Proponent has suggested that in some circumstances primary depletion may be used for smaller fault blocks where two-well development is not economical, or where thin bedding would limit communication between a producer and injector pair. Prior to developing any resources on primary production, a separate approval will be required from the Board.

The Proponent's selected proposal includes five oil producers drilled from the Hibernia GBS and five water injectors drilled from a sub-sea template located 7 km southeast of the Hibernia Platform. In the course of assessing the HSE Unit, the Proponent evaluated several combinations of platform and subsea wells including drilling all wells from the platform, drilling all wells from subsea templates and the combination that was ultimately proposed in the Application. The Proponent determined that, given the slot constraints on the platform and the drilling risk involved with long step-out wells, the selected option is preferred.

The wells will be drilled with each producer positioned at a structural high point in a fault block, and the associated water injector located downdip. The Proponent will seek approval for the final well locations in Approval to Drill a Well applications prior to commencing well operations.

The proposed drilling schedule presented in the document has five platform-based production wells drilled from existing GBS slots beginning in 2013. Drilling of the five sub-sea water injectors is expected to begin in Q2 2013. Recent drilling performance on the Hibernia Platform and the Proponent's latest drilling schedule (from June 2010) suggest that the drilling of the first platform producer (OPKK1) could begin as early as Q1 2011. Board staff recognize that earlier drilling of some of the platform producers will provide information that will help the Proponent reduce uncertainty and risk as it develops the remainder of the HSE Unit.

Due to the planned timing of the subsea campaign to install the water injection manifold, template and flowlines, it is not likely that the water injectors will be drilled earlier than Q2 2013. Should drilling of the HSE Unit production wells begin in 2011, early production without injection support must be limited to ensure good reservoir management. Board staff will expect this issue to be considered and discussed in applications for Approval to Drill a Well.

According to the Application, the Proponent plans to install two three-slot manifolds in a glory hole for the water injection wells. Board staff considered whether this configuration would allow for flexibility should drilling problems be encountered, or should drilling results indicate substantial upside potential for the HSE Unit. The Proponent plans to drill five water injectors, leaving one un-utilized drill slot available. In addition, the Hibernia Platform was designed to accommodate several remote tie-back projects through J-tubes built into the platform at the time of construction. The water injection manifold for the HSE Unit will only use one of these J-tubes, leaving additional J-tubes for possible future development. Board staff are satisfied that the design for the subsea template is adequate to exploit known resources from the HSE Unit area, and that there is flexibility in the Hibernia Platform design to allow for future expansion should drilling results indicate significant potential for upside development.

The HSE Unit development will incorporate some of the longest reach wells to be drilled within the waterflood region. Some issues have been encountered recently with producing oil with high water cut from wells on the flanks of the field. In the past, problems of this nature have been addressed by perforating additional zones in upper intervals, which decreases water cut by adding dry oil to the flowstream. The Proponent is currently undertaking a project to add gas lift on the Hibernia Platform, with a target implementation date of 2012. Board staff recognize that gas lift is an effective enhanced recovery method in waterflooded regions, and expects that HSE Unit production wells will be completed with gas lift capability if possible. This will be considered for each well in the Approval to Drill a Well process for the HSE Unit.

The Application indicates that injection fluid for the HSE Unit water injectors will be seawater that is sourced and treated in the same manner as water currently injected into the Hibernia reservoir. Board staff agree with the Proponent's assessment that compatibility issues are unlikely; however, data acquisition for the HSE Unit water injectors must include the collection and testing of a water sample, for at least the initial water injector, to ensure there are no compatibility issues.

The Board's staff notes that the Proponent's estimated costs for drilling and tie-in of HSE Unit development wells are estimated at $1,735,000,000 CAD. Table A.4 provides a breakdown of this cost estimate. Staff believe this estimate is reasonable based on internal review of historical drilling cost data for the Hibernia Field and the cost for other sub-sea installations in the NL Offshore Area.

Table A.4: Cost Estimate for HSE Unit Development Project. (Source: HMDC)

Pre-Development	$ 150 M
Glory Hole	$ 40 M
Subsea	$ 260 M
Engineering & Project Management	$ 100 M
Topsides Modifications	$ 30 M
Platform Drilling	$ 375 M
Subsea Drilling	$ 760 M
Well Tie-Ins / Workovers	$ 20 M
Total HSE Unit	$ 1735 M

A.5 Reservoir Simulation Model

The full-field model used to prepare the Application comprises six sector models controlled by a set of Well Management Logic. Both the Well Management Logic and the reservoir simulator EM^{Power} are proprietary to the Proponent. The Hibernia sector model that includes the HSE Unit is entitled 'South Sector and HSE' (see Figure A.4).

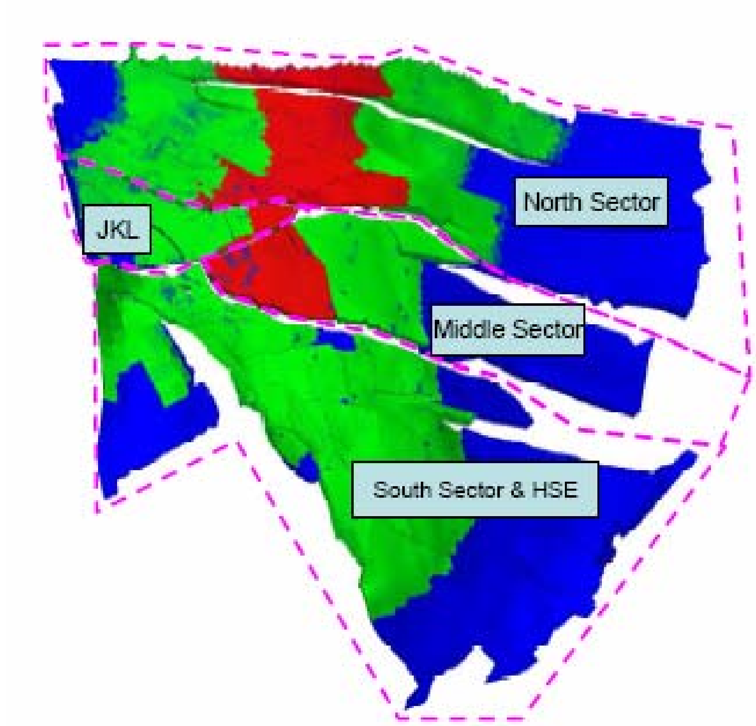


Figure A.4: Hibernia A and B Pool Sector Models Contained Within the Full-Field Model. (source: HMDC)

Board staff reviewed the simulation results and met with the Proponent in a workshop to review the South Sector and HSE model. Through this workshop and the review of the reservoir simulation results, Board staff determined that the methodology and constraints used to develop the model were reasonable. The simulation results are within the range of expected outcomes, given the uncertainty of the geological model that was previously discussed.

A.6 Production Forecast

The Board's staff reviewed oil production forecasts provided by the Proponent for the HSE Unit. Figure A.5 shows that production will begin in 2013 from GG1 Block at an average of 1300 bbls/d in 2013, up to a maximum of 45,500 bbls/d when all blocks are online in 2015. Production is expected to last until 2040 with a cumulative production of 107.6 MMbbls.

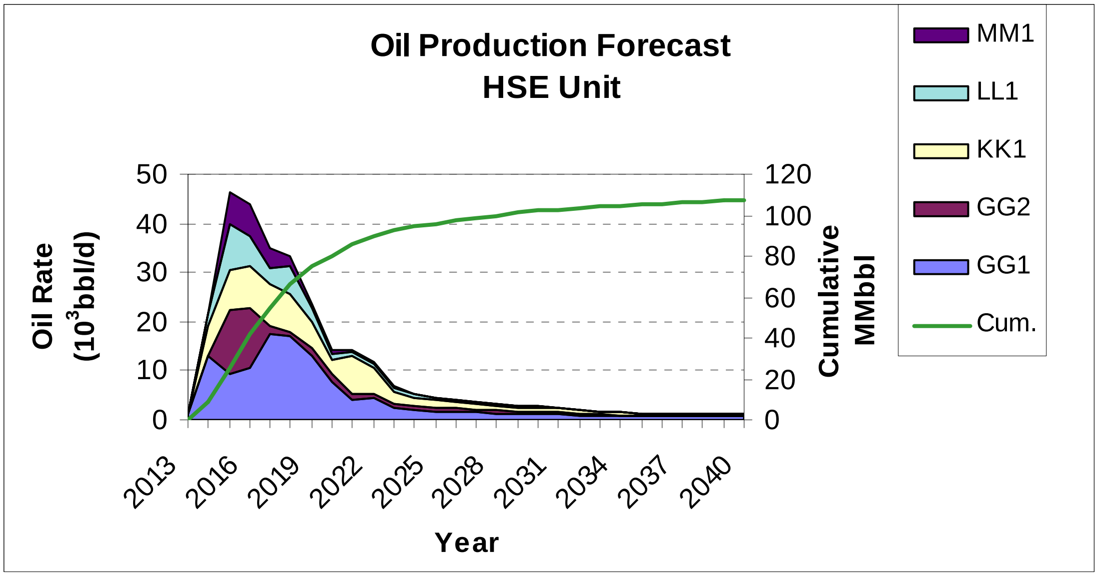


Figure A.5: HSE Unit Oil Production Forecast. (Source: C-NLOPB from HMDC)

Gas production is estimated to reach a maximum of 26.9 million standard cubic feet per day (MMscf/d) in 2015, and decline with decreasing oil production from the HSE Unit (Figure A.6).

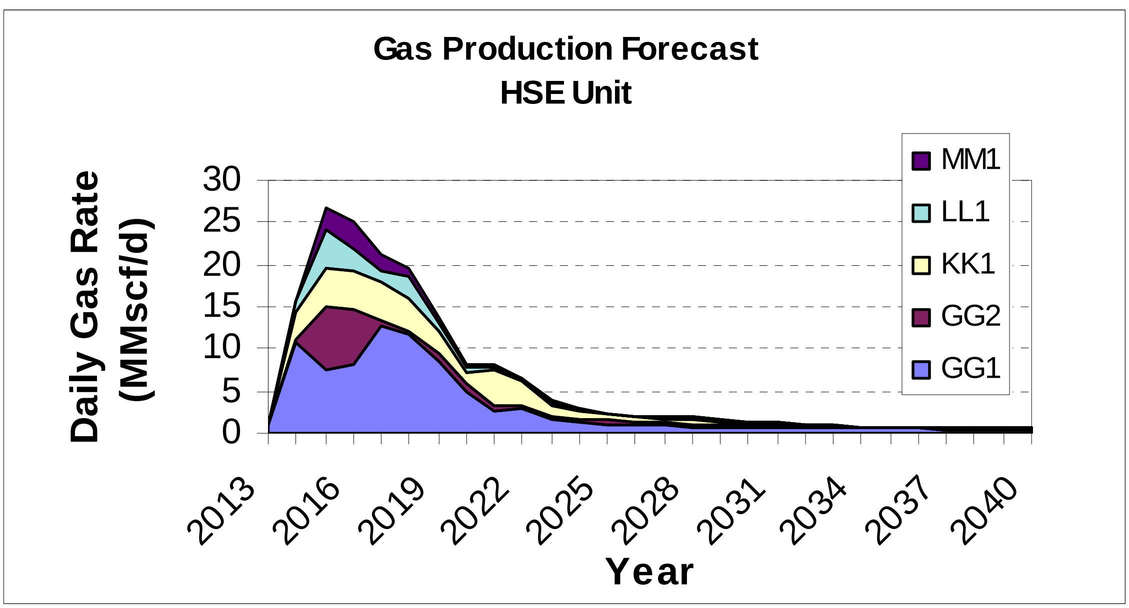


Figure A.6: HSE Unit Gas Production Forecast. (Source: C-NLOPB from HMDC)

Water production is estimated to reach a maximum of 46,680 bbls/d from the HSE Unit in 2023 (Figure A.7).

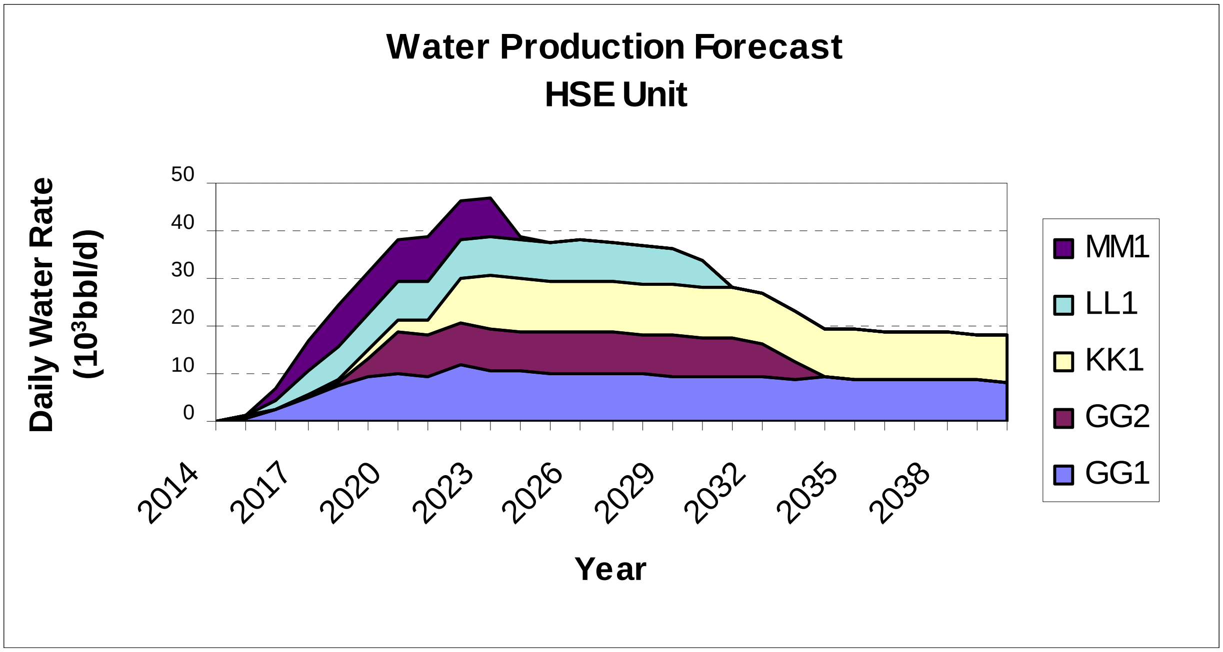


Figure A.7: HSE Unit Water Production Forecast (Source: C-NLOPB from HMDC)

A key consideration for the Board's staff is whether the current production facilities enable oil and gas recovery from the field to be maximized in accordance with sound economic and engineering principles. Staff are confident that continuing operations with the current facility capacities will not lead to a reduction in oil recovery from the HSE Unit. Staff analysis has also concluded that the anticipated current forecast of oil, water and gas production from the HSE Unit can be handled by the current facilities and will help the facilities remain near capacity as production from the main Hibernia Field declines.

An analysis of the water injection forecast for the field indicates that the water injection requirements for the HSE Unit are reasonable and will not cause strain on the systems currently in place on the Hibernia Platform. The current platform capacity for water injection is 295,000 bbls/d, however this requires all four water injection pumps to be running, and this is limited due to power constraints. The Hibernia Platform achieved a daily water injection average up to 265,100 bbls/d in 2006. According to the forecast, the maximum daily average water injection that will be required in the future, including all current development along with the HSE Unit, will be 256,700 bbls/d, well within the capacity of the platform facilities. The historical and forecasted water injection rates are presented in Figure A.8. Board staff recognize that the Hibernia Platform has the facilities to handle the volume of water injection required to develop the HSE Unit.

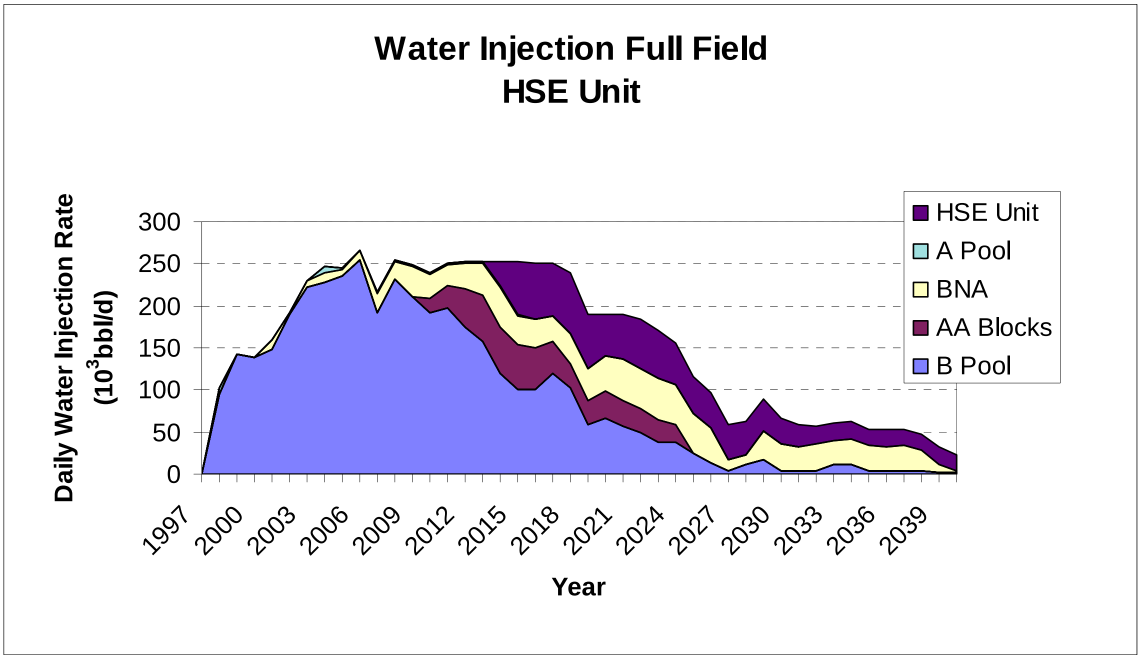


Figure A.8: Hibernia Full-Field Water Injection Forecast. (Source: C-NLOPB from HMDC)

The HSE Unit development will follow a reservoir management plan similar to the rest of the Hibernia waterflood blocks. The plan is to target a voidage replacement ratio of one, to maximize ultimate recovery. A "bottoms-up" strategy of perforating the lowermost intervals first will be employed in the platform producers; however, in the subsea injectors, the plan is to open all reservoir intervals with the initial completion. This is a reasonable approach given the operational and economic costs of performing intervention work on subsea wells. The Proponent and Board staff agree that this strategy is not likely to impact ultimate recovery from the HSE Unit.

The proposed depletion scheme for the HSE Unit is reasonable. The Board's staff will continue to work with the Proponent to ensure future development of the HSE Unit will not negatively impact other undeveloped fault blocks within the field.

A.7 Development of the HSE Unit Within the Context of Hibernia Full Field

Board's staff considered the HSE Unit development in the context of its impact on the overall Hibernia Field development, including opportunities within pools/reservoirs under development. It is the assessment of Board staff that development of the HSE Unit will not negatively impact the development of the Hibernia B Pool, AA Blocks, Ben Nevis-Avalon reservoir or A Pool.

Staff have determined that the HSE Unit development is timely, as it represents one of best development opportunities remaining in the field, and will help offset production decline in the main Hibernia Field.

A.8 Conclusions and Recommendations

- The structural model, reservoir quality, and position of oil-water contacts for the HSE Unit are the primary sources of uncertainty leading to a range of possibilities in estimating volumes for this area of the field.

- Board staff emphasize the importance of thorough data acquisition in the initial stages of development of the HSE Unit to resolve geological uncertainties in further development.

- The Proponent's most likely estimates of STOOIP volumes [260.8 MMbbls (41.5 MMm^3) of oil and 139.1 GCF (3.9 Gm^3) of gas] based on an oil-water contact of 4816 m TVDSS are considered possible.

- The Proponent's recovery factor (41%) is consistent with the Board's staff estimate.

- Based on a review of geological, petrophysical and reservoir engineering data, staff concur with the Proponent that the proposed waterflood strategy is the best approach.

- The Proponent's depletion strategy, consisting of ten wells (five oil producers drilled from the Hibernia Platform and five subsea water injectors), is reasonable.

- The Proponent's expected production forecast for the HSE Unit will reach a maximum of 46,500 bbls/d with an estimated cumulative production of 107.6 MMbbls.

- The Proponent's range of estimated ultimate recovery from 68.3 MMbbls to 169.3 MMbbls, with 107.6 MMbbls being the most likely, is reasonable given the uncertainty that exists within the HSE Unit.

- Significant facilities work will be required to bring a subsea template online for water injection in the HSE Unit. No significant plant upgrades will be required.

- The development of the HSE Unit as described in the Application will not negatively impact the development of the Hibernia B Pool, AA Blocks, Ben Nevis-Avalon reservoir or A Pool.

- HSE Unit development is timely as it will offset Hibernia field decline and optimize facility utilization.

Board staff recommend that the development of the HSE Unit be approved as described in the Application.

Appendix B

Hibernia B Pool

B.1 Hibernia B Pool Update

The Hibernia B Pool has been the main reservoir exploited since first oil from the Hibernia Field in 1997. In this appendix, the B Pool refers to the Hibernia main field, the area addressed in the original Hibernia Development Plan. The B Pool is located entirely within PL1001 and does not include B Pool in AA Block or within the Hibernia Southern Extension (HSE) Unit area, as those reservoirs are addressed in separate appendices. As of June 2010, the B Pool has contributed 649 MMbbls of the 690 MMbbls (94%) produced from the Hibernia Field to date.

B.2 Geological/Geophysical Review

As the Proponent's geological model for the Hibernia reservoir has not changed significantly in the developed portion of the field, no new geological model for the full field was submitted in support of this Application. The Proponent's 2008 full-field model, reviewed previously by Board staff, continues to represent an appropriate and reasonable geological and geophysical interpretation of the field.

B.3 Petrophysical Review

The Proponent has conducted a comprehensive logging and coring program of the Hibernia B Pool while drilling the exploration, delineation and development wells in the Hibernia field. In the document, the Proponent summarized their petrophysical interpretation for these wells. HMDC supplied supplemental information on the methodology, assumptions and criteria used in the Hibernia Formation petrophysical analysis.

Staff reviewed the petrophysical data and determined that the Proponent's interpretation of the Hibernia B Pool is similar to Staff's assessment with slight differences attributed to different methodology, assumptions and criteria used in interpreting the data. Based on its analyses, Board staff believes the interpretation presented by the Proponent in support of this application is reasonable and appropriate to evaluate this application.

B.4 Development Strategy Update

As the Proponent indicated in the Application, the development strategy for the Hibernia B Pool has remained unchanged since the start of the project. The overall development strategy includes: pressure maintenance by water or gas injection; focus on expansion and optimization of existing production; and injection wells within structurally defined fault blocks using existing platform infrastructure. Primary depletion is only considered in special circumstances where two-well development is uneconomic or where thin reservoirs exist with no communication to nearby wells. No primary depletion project can be carried out without Board approval.

The Hibernia B Pool can be divided into two primary regions, the gasflood region in the northeast wedge of the field, consisting of A, B, C, G, F/H, I and D/N Blocks, and the waterflood region consisting of the remaining fault blocks in the field. These regions are highlighted in Figure B.1.

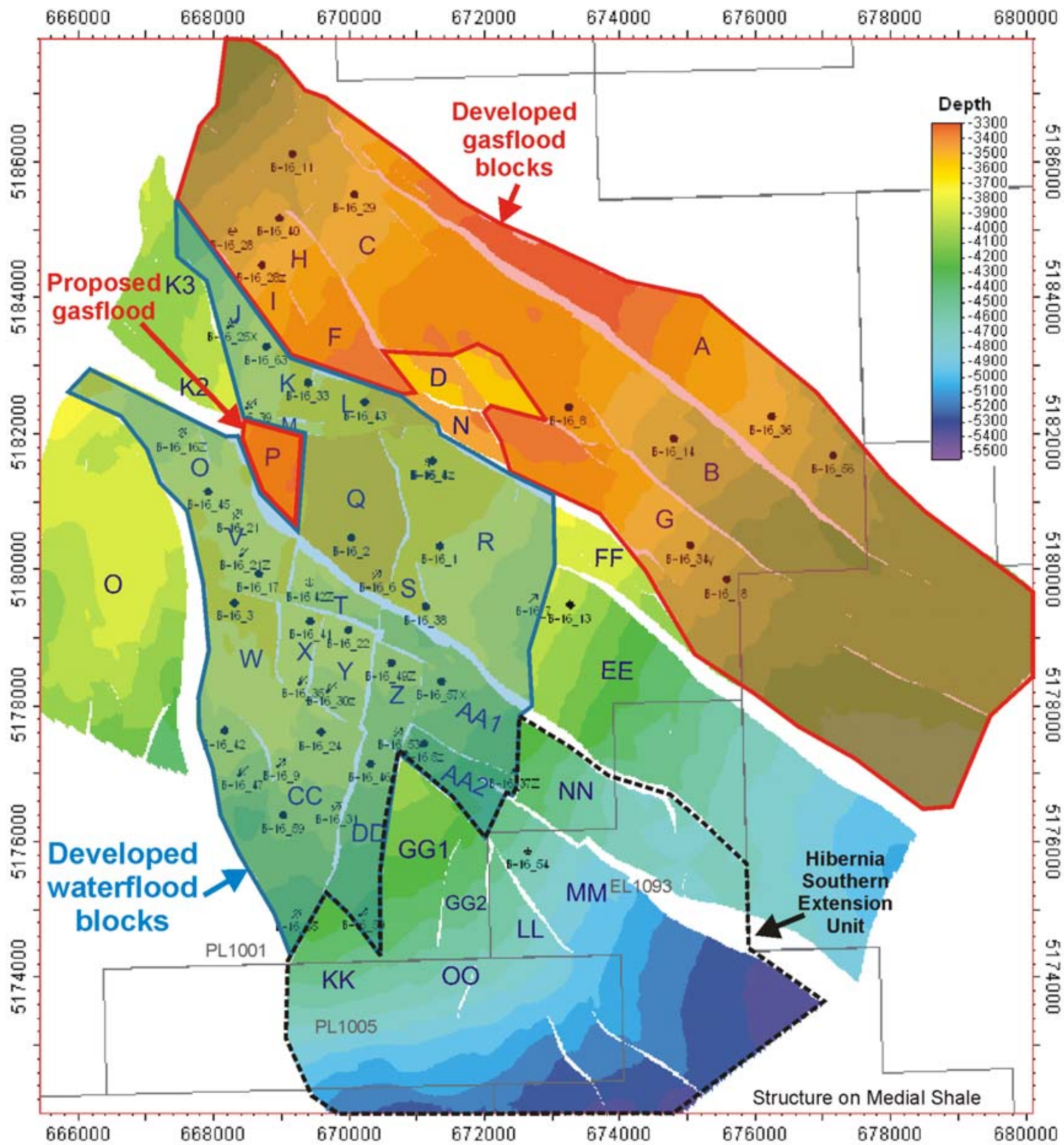


Figure B.1: Map of Hibernia Field Showing Developed Waterflood and Gasflood Areas. (Source: C-NLOPB)

B.4.1 Gasflood Region Update

In the northeastern part of the Hibernia reservoir, gas re-injection provides pressure support to oil production. In addition to gas produced from the wells in this region, gas produced in association with oil from the waterflood area is also injected into this region. The gasflood region is mature and contains ten producers and six gas injectors that are located in six of the seven blocks. The tenth producer, B-16 56 was drilled in A Block and was completed in Q2 2010.

Several of the production wells in the gasflood area have experienced gas break-through; however, oil production from this region has remained relatively stable, and has been increased to offset production decline in the waterflood area.

Gas processing and injection capacity are the main factors limiting oil production from the gasflood region to date (Figure B.2). The processing and injection facilities are currently operating at or near capacity, i.e. gas injection capacity is 260 MMscf/d (7.4 million Sm^3/d) according to the Application. The Proponent has been able to stabilize the gas-oil ratio by reducing or suspending production at wells that experience gas breakthrough, and prioritizing production from low gas-oil ratio wells in the waterflood region. This is possible because there is sufficient production capacity in other wells, or new wells coming on-stream, to make up for the loss of production in any particular well. In addition, there is sufficient gas supply from the waterflood area to maintain oil production rates.

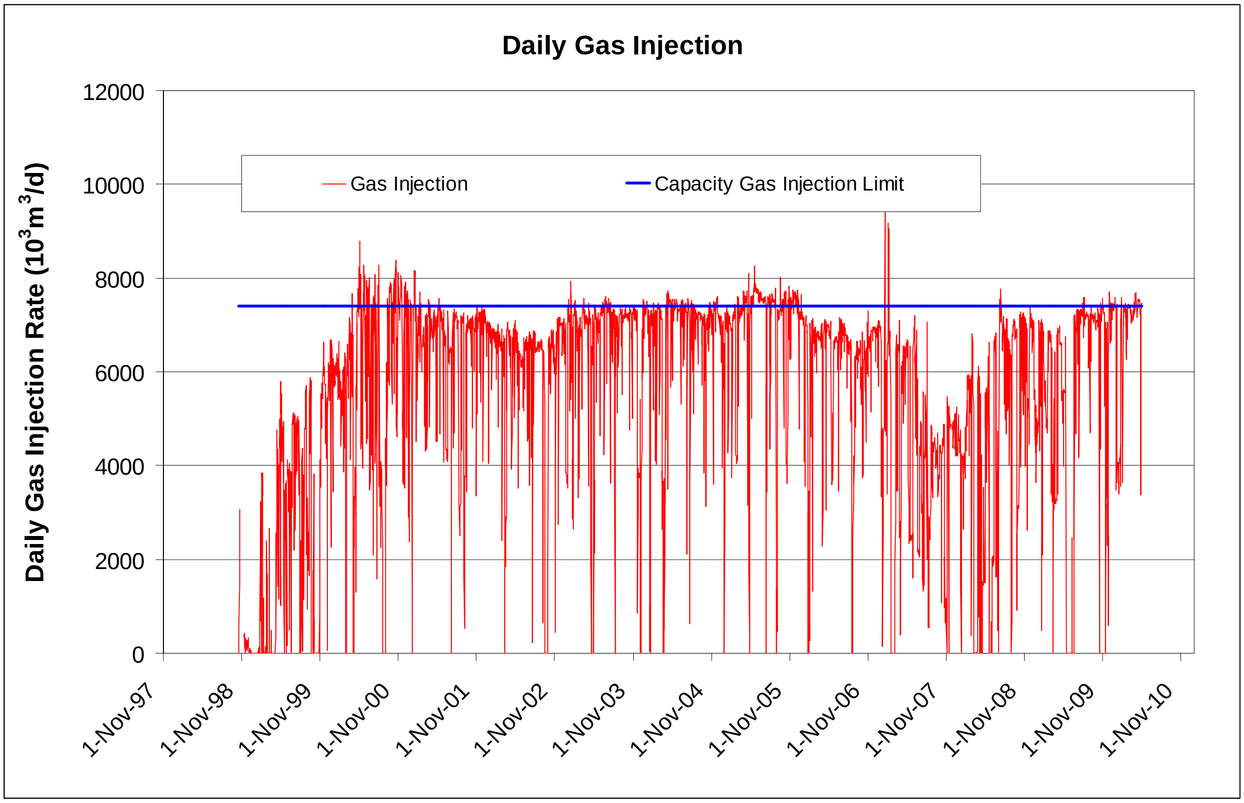


Figure B.2: Hibernia Field Gas Injection Rate. (Source: C-NLOPB)

As the gasflood region continues to mature, the gas-oil ratio is expected to increase significantly, limiting the gas handling capacity available for processing gas from the waterflood region. In addition, as production from the waterflood region declines, there will be less gas available to support the gasflood. This situation, along with decreased oil production from wells experiencing gas breakthrough, is expected to lead to an eventual decline in production from the gasflood region. This may be somewhat offset by injection of gas that will be produced as part of HSE Unit development.

In the gasflood area, the B-16 56 oil producer was recently completed in the A Block. Other areas of opportunity considered upside and not listed on the current drilling schedule are the A-West, D2 and N Blocks. Board staff will continue to assess potential for upside development in the gasflood region in the annual review of the Proponent's Resource Management Plan.

B.4.2 Waterflood Region Update

The Hibernia B Pool waterflood region is at an advanced stage of depletion, with 17 oil producers in 16 blocks, supported by 14 water injectors.

Recently, development of the waterflood region in the Hibernia South area began with the first well being drilled in the AA1 Block. To date there are two oil producers and one water injector in the AA Blocks.

As with the gasflood region, the Board's staff acknowledges that in some blocks the recoverable reserves from the waterflood area could are likely higher than the 2006 Board estimates. A detailed examination of the reserves in the waterflood region is discussed in Section B.4.4.

The Proponent continues to utilize a "bottoms-up" strategy of isolating lower, watered-out zones and opening higher oil zones. However, in some recent instances, in outlying areas of the waterflood region, the Proponent has perforated multiple zones at once in order to minimize hydraulic lift issues until gas lift becomes operational. Installation of gas lift is anticipated in 2012.

Overall, Board staff are satisfied that the waterflood region is being well managed by the Proponent in order to maximize recovery and optimize facility use. The challenge for the Proponent will be to manage water production from existing wells while bringing on new opportunities.

B.4.3 P Block Depletion Scheme

The Proponent now plans to implement gasflood in the Hibernia P Block, as opposed to the waterflood scheme that has already been approved. In the initial (1990) Development Plan for the Hibernia Field, a gas flood scheme was proposed; however, this was changed to waterflood in the 1996 Development Plan Amendment Application.

Oil reserves for the P Block are estimated to range from 11 to 29 MMbbls (1.8 to 4.6 MMm^3). The P Block is located in a structurally complex part of the field where there is some uncertainty in the structure and fluid contacts. Based on waterflood and gasflood performance in areas of the reservoir currently being exploited, Board staff believe that either a gasflood or waterflood scheme may be successfully applied to the P Block, depending on the nature of the fluids in the reservoir at this location.

The Board's staff reviewed the latest structural interpretation and estimated location of the gas-oil and oil-water contacts. This review suggested that a gas cap is likely to exist in the P Block. Staff believe that the proposed depletion scheme, consisting of gasflood with a producer and a gas injector, is reasonable and should efficiently deplete the oil reserves in this block. As noted previously, there is uncertainty in the structure and fluid contacts so it is possible that a gas cap may not be present. In this case, a waterflood scheme may be more appropriate.

Following drilling of the proposed development wells in the P Block (scheduled for 2026), the Board's Chief Conservation Officer will review the information and assess the adequacy of the proposed gasflood depletion scheme P Block.

B.4.4 Reserves Estimates

The Proponent's most likely recoverable reserves estimate for the Hibernia B Pool (excluding the HSE Unit and AA Block) is 911.8 MMbbls, which includes areas that have been developed and areas that are currently on the drilling schedule. Upside development brings the Proponent's estimate for the B Pool to 956.3 MMbbls.

The latest reserves estimate conducted by the C-NLOPB was completed in 2006. The estimated ultimate recovery from the B Pool in this area was 812.5 MMbbls; however, production from some blocks has outperformed the expected recoveries.

In the gasflood region, decline analysis indicates that recovery factors will be much higher than originally anticipated. In the 2006 reserves estimate, recovery factors from the gasflood region were expected to average 50.3%. Based on production decline analysis, recovery factors are now expected to be approximately 70%. Subsequently, the reserves estimate from the gasflood region has increased from 277.8 MMbbls to 387.3 MMbbls. The Proponent's estimate for this region is 426.8 MMbbls. The Proponent's estimate includes NGL's generated from gas processing and compression. Previously, NGL's were estimated to be 45.3 MMbbls.

Table B.1 shows a comparison of the Board's 2006 reserves estimate, newly revised estimates based on analysis of the production data and the Proponent's reserves estimates for the gasflood region as presented in the Application. No changes have been made to the 2006 STOOIP estimates. Board staff recognizes that the STOOIP estimate for the F/H Block is low based on production to date. All STOOIP estimates will be reviewed in the Board's next evaluation of reserves and resources in the Hibernia Field.

Table B.1: Comparison of C-NLOPB 2006 and 2010 Reserves Estimates, and Proponent's Current Estimates for the Gasflood Region. (Source: C-NLOPB)

		CNLOPB 2006			CNLOPB 2010		HMDC 2010		
Block	Well	STOOIP	CNLOPB 2006	RF	Decline Analysis	RF	STOOIP	HMDC 2010	RF
		(MMbbl)	(MMbbl)	%	(MMbbl)	%	(MMbbl)	(MMbbl)	%
G Block	B-16 18				31.8			37.9	
	B-16 34Y				32.8			28.9	
	Total	85.4	42.7	50.0%	64.6	75.6%	85.2	66.8	78.4%
F/H Block	B-16 40	23.1	11.6	50.2%	29.1	126.0%	44.6	36.4	81.6%
I Block	B-16 28Z	29.6	16.2	54.7%	23.8	80.4%	38.6	23.1	59.8%
B Block	B-16 14	86.2	43.1	50.0%	48.7	56.5%	79.5	54.9	69.1%
C Block	B-16 8				25			34.2	
	B 16 11				23.8			20.4	
	B-16 29				50			68	
	Total	152.1	76	50.0%	98.8	65.0%	149.6	122.6	82.0%
A Block	B-16 36				68.2		81.8	68.9	84.2%
	B-16 56				54.1		64.2	54.1	84.3%
	Total	176.4	88.2	50.0%	122.3	69.3%	146	123	84.2%
Gasflood Total		552.8	277.8	50.3%	387.3	70.1%	543.5	426.8	78.5%

A decline analysis of select blocks in the waterflood region also shows an increase in some recovery factors. Blocks that are now expected to outperform the Board's 2006 reserves estimates include K, L, Q, R, V, X, Y and Z. Blocks that have been abandoned, or are expected to be abandoned in the near future, namely BB and EE, were also reviewed.

Table B.2 presents a comparison of the Board's 2006 reserves estimates, a revised estimate based on analysis of the production data and the Proponent's reserves estimates for selected blocks in the waterflood region. In the 2006 reserves estimates, these blocks were expected to produce 275.7 MMbbls, and have an average recovery factor of 49%. Based on decline analysis of the most recent production data, these blocks are now expected to produce 316.9 MMbbls with an average recovery of 56.3%.

Table B.2: Comparison of C-NLOPB 2006 and 2010 Reserves Estimates, and Proponent's Current Estimates for Selected Blocks from the Waterflood Region. (Source: C-NLOPB)

		CNLOPB 2006			CNLOPB 2010		HMDC		
Block	Well	STOOIP	CNLOPB 2006	RF	Decline Analysis	RF	STOOIP	HMDC 2010	RF
		(MMbbl)	(MMbbl)	%	(MMbbl)	%	(MMbbl)	(MMbbl)	%
K Block	B-16 33	40.7	14.2	34.9%	15.9	39.1%	31.9	15.1	47.3%
L Block	B-16 43	28	11.2	40.0%	14.2	50.7%	12.5	16.9	135.2%
Q Block	B-16 2	68.8	48.1	69.9%	53	77.0%	71.4	54.4	76.2%
R Block	B-16 1				44.9			45	
	B-16 4z				83.7			80.6	
Total		219	118.2	54.0%	128.6	58.7%	198.6	125.6	63.2%
V Block	B-16 17	75.4	29.2	38.7%	34.2	45.4%	54.8	32.7	59.7%
BB Block	B-16 42	12.1	4.21	34.8%	7.35	60.7%	12.6	8.2	65.1%
EE Block	B-16 13	14.8	4.47	30.2%	1.1	7.4%	14.5	0.8	5.5%
X Block	B-16 41	29.7	10.9	36.8%	16.6	56.0%	27.5	18.7	68.0%
Y Block	B-16 22	35.4	17.7	50.0%	22.2	62.7%	36.3	24.3	66.9%
Z Block	B-16 49Z	38.8	17.5	45.1%	23.7	61.1%	35.1	19.2	54.7%
Water Flood Total		562.7	275.68	49.0%	316.85	56.3%	495.2	315.9	63.8%

In summary, the Board's 2006 reserves estimate for the Hibernia B pool (excluding HSE Unit and the AA Blocks) was 812.5 MMbbls. Production data since 2006 has indicated that this assessment needs to be increased by 150.8 MMbbls bringing the revised reserves estimate for this area to 963.3 MMbbls.

Table B.3: B Pool Block-by-Block Reserves Summary. Gasflood Block are Shown in Red, Waterflood in Blue (Field Units). Reserve estimate for HMDC includes upside opportunities. (Source: C-NLOPB)

	C-NLOPB 2006	C-NLOPB 2010	HMDC
	B Pool Total	**B Pool Total**	**B Pool Total**
A	88.21	122.30	123
B	43.09	48.70	54.9
C	76.06	98.80	122.6
D	6.69	6.69	8.6
F	5.82	29.10	36.4
G	42.72	64.60	66.8
H	5.75		
I	16.25	23.80	23.1
J	5.72	6.09	8.2
K	14.24	15.90	15.1
L	11.20	14.20	16.9
M	0.00	0.00	0
N	0.00	0.00	0
O	53.42	53.42	12.1
P	4.51	4.51	8.5
Q	48.12	53.00	54.4
R	118.27	128.60	125.6
S	6.89	6.89	4.3
T	4.32	4.32	4.9
U	0.00	0.00	0
V	29.16	34.20	46.3
W	64.72	64.72	60.2
X	10.97	16.60	18.7
Y	17.71	22.20	24.3
Z	17.47	23.70	19.2
BB	4.22	7.35	8.2
CC	64.93	64.93	53.5
DD	29.49	29.49	37.3
EE	4.45	1.10	0.8
FF	18.08	18.08	2.9
Total	812.49	963.28	956.80

* AA Blocks and HSE Unit Reserves not included.

The Proponent's and the Board's reserves estimates are significantly different in the CC and O Blocks. The difference in the CC Block is primarily due to the difference in STOOIP (144 MMbbls for the Board vs. 99 MMbbls for the Proponent). The Proponent carries 53.5 MMbbls for the CC Block, whereas the Board's estimate is 64.9 MMbbls. The difference in O Block is primarily due to the Board accounting for reserves in O2 and O3 sub-blocks where the Proponent does not recognize any reserves. The Proponent's reserves estimate for O Block is 12.1 MMbbls, in contrast to the Board's estimate of 53.4 MMbbls.

Board staff considers the Proponents STOOIP and reserve estimate for B Pool to be reasonable. STOOIP and reserves will continued to be re-evaluated as more drilling and production data becomes available.

B4.4 Reservoir Simulation Model

The full-field simulation model used to prepare the Application comprises six sector models controlled by a set of Well Management Logic. Both the Well Management Logic and the reservoir simulator EM^{Power} are proprietary to the Proponent. The Hibernia sector model that incorporates the B Pool includes "North Sector", "JKL", "Middle Sector" and parts of "South Sector & HSE" (Figure B.3).

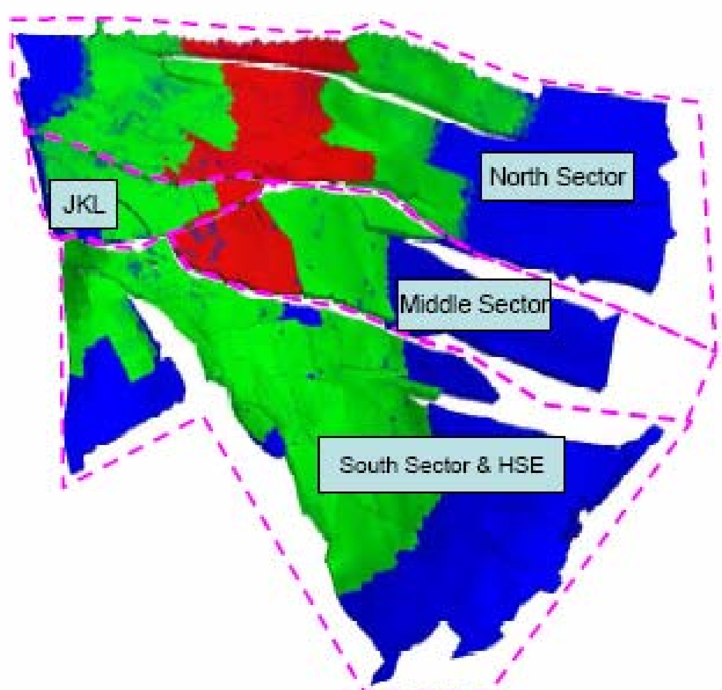


Figure B.3: Hibernia A/B Pool Sector Models Contained Within the Full-Field Model. (Source: HMDC)

The sector models that comprise the full-field model have been developed as "black oil" models, or models that assume the fluid composition remains the same throughout the life of the field. In the past, there was some concern that the North

Sector model representing the gasflood region, being a black oil model, did not adequately represent the area. It was determined that a compositional model would be more appropriate. As described above, the Hibernia full-field model is comprised of the six individual sector models, running in conjunction with each other to best represent the entire field. Due to software limitations, it is impossible to combine black oil and compositional models.

The Proponent submitted a study entitled *Hibernia North Sector Compositional Simulation Study*, dated July 2008, as a Part II document accompanying the Application. The purpose of the study was to develop a compositional model for the gasflood region to validate the black oil model used in the Hibernia full-field model. Prior to developing the compositional model for the gasflood region, the Proponent performed a detailed history match of the North Sector model. The details of this history match were presented in an August 2007 study entitled *Hibernia North Sector Gas Flood Model History Match Report*, which was also included as a Part II document to support the Application. The main conclusions from the history match report were that the black oil simulation model adequately represented production performance including GOR, water cut and pressure trends in the gasflood region. The learnings from the history match report were incorporated into development of the compositional model.

The main conclusion from the Hibernia North Sector Compositional Simulation Study is that the compositional model matches actual observed well data from the gasflood region. The black oil model with oil vaporization (Rv) degradation does an acceptable job of representing the compositional model behaviour and this has now been included in the Hibernia full-field model.

B4.5 Production Forecast

The Board's staff reviewed the production forecasts provided by the Proponent for the B Pool. Production from the B Pool began in 1997 and peaked in 2003 with an average production of 197,400 bbls/d. Production has maintained a plateau of approximately 190,000 bbls/d from 2003 to 2005, and has been in decline ever since. In 2009 production from B Pool was 106,900 bbls/d and rates are expected to continue to decline for the life of the field. Figure B.4 shows the historical and forecasted production from the B Pool.

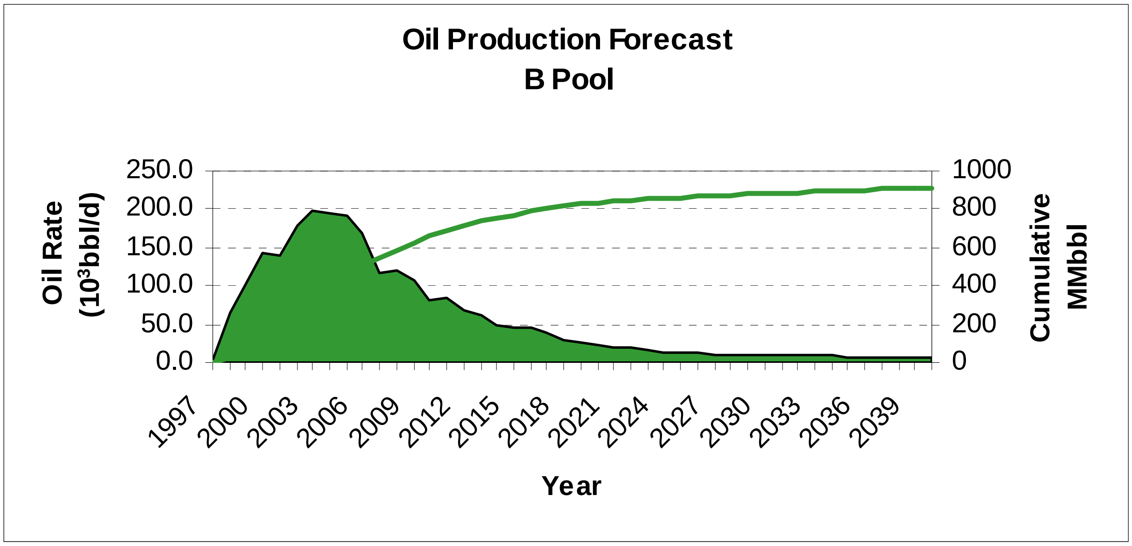


Figure B.4: B Pool Oil Production Forecast. (Source: C-NLOPB from HMDC)

Gas production from B Pool reached a peak of 269.7 Mscf/d in 2005. Although oil production is declining, gas production rates are expected to remain relatively constant as higher GOR oil, particularly from the gasflood region, is produced over the life of the field. In 2009, B Pool gas production averaged 226.6 Mscf/d. Gas production is expected to drop to as low as 201.3 Mscf/d in 2019, but then rise to 240 Mscf/d and remain at this level for the life of field. Figure B.5 shows the historical and forecasted gas production from the Hibernia B Pool.

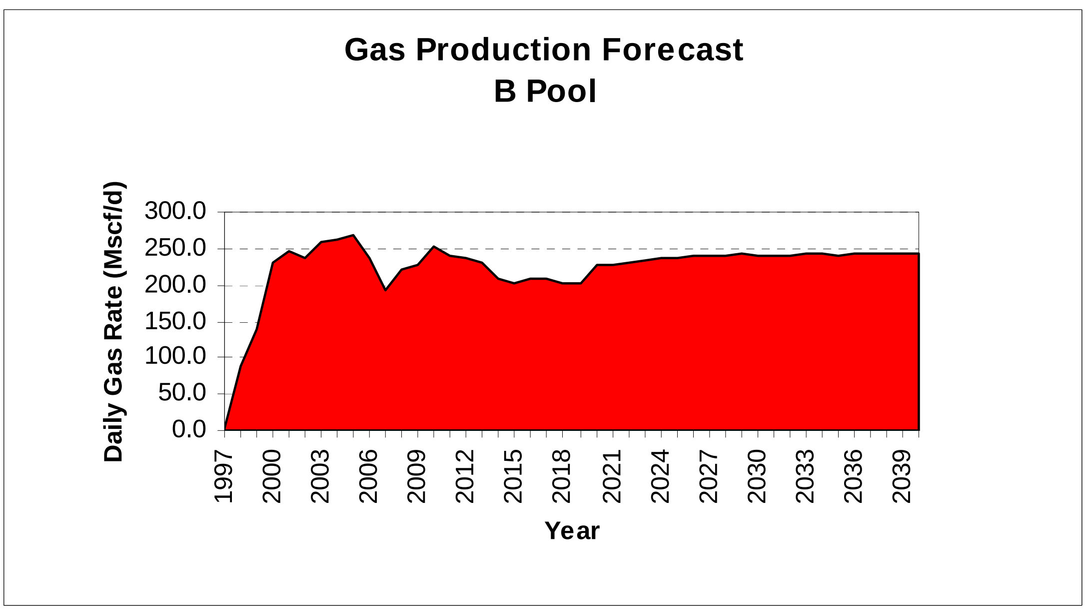


Figure B.5: B Pool Gas Production Forecast. (Source: C-NLOPB from HMDC)

Water production from the B Pool peaked in 2003 with an average water production rate of 123,000 bbls/d. Over the life of the Hibernia Field, the Proponent will continue to dedicate significant resources to managing B Pool production to maximize resource recovery while limiting water production. The "bottoms-up" development strategy, whereby lower intervals are isolated when production drops below 200 m^3/d and water-cut is greater then 95%, has allowed the Proponent to continue to produce from wells while significantly reducing water cut. According to the Proponent's forecast, water production from the B Pool will decline significantly, particularly at the tail end of the field life, after 2021. Figure B.6 shows the historical and forecasted water production from the Hibernia B Pool.

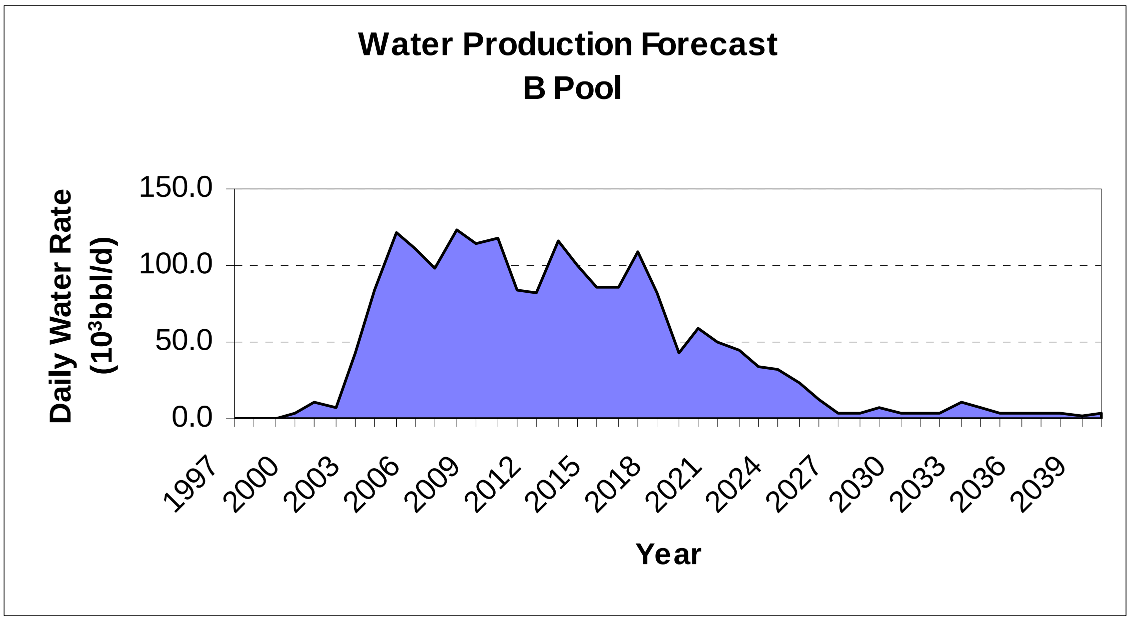


Figure B.6: B Pool Water Production Forecast. (Source: C-NLOPB from HMDC)

A key consideration for the Board's staff is whether the current production facilities enable oil and gas recovery from the field to be maximized in accordance with sound economic and engineering principles. Staff are confident that continuing operations with the current facility capacities will not lead to a reduction in oil recovery from the B Pool as new opportunities are brought on-line. The staff analysis has also concluded that the forecast of oil, water and gas production from the B Pool can be handled by the current facilities and that new developments will help the facilities remain near capacity as production from the B Pool declines.

Upon review of the oil, gas and water production forecasts for the Hibernia B Pool, Board staff believe that the production forecast for the B Pool field life is reasonable.

B.5 Conclusions and Recommendations

- The Proponent's best estimates of STOOIP volumes [1463.7 MMbbls (232.7 MMm^3) of oil and 2451.6 GCF (69.4 Gm^3) of gas] are considered reasonable.

- The Proponent's recovery factor of 65% is somewhat higher than the Board's recovery factor of 56%; however, it is considered reasonable.

- Based on a review of geological, geophysical, petrophysical and reservoir engineering data, including production to date, waterflooding and gasflooding have been appropriate modes of development for the Hibernia B Pool.

- Production from B Pool indicated that the Board's latest reserve estimate for Hibernia, conducted in 2006, needed to be updated.

- Resource Management staff have concluded that no significant changes to the Hibernia main field B Pool reservoir development are necessary. B Pool development will not be adversely affected by the addition of the HSE Unit.

Board staff recommend that an additional 150.8 million barrels of oil reserves should be added to the Hibernia B Pool reserves, increasing the Hibernia Field oil reserves estimate to 1395 million barrels from 1244 million barrels.

Appendix C

Hibernia A Pool

C.1 Hibernia A Pool Update

The initial Hibernia Development Plan submitted in 1986 focused on the B Pool, with A Pool considered a deferred development opportunity. In 1997, Condition 97.01.1 of Decision 97.01 stated:

'Prior to initiating of production from the Hibernia 'A' pools, the Proponent submit its depletion plan therefore for the approval of the Board.'

In June 2008, HMDC submitted The Hibernia A Pool Depletion Plan, which was accepted by the Board, satisfying condition 97.01.1 in January 2009. This depletion plan included the exploitation scheme which comprised:

1) Isolation of Hibernia A Pool in existing wells as they become available;
2) Commingling of Hibernia A Pool with Hibernia B Pool production as wells near their end of life; and
3) Waterflood or gasflood development with producer/injector pairs in select instances, using existing wellbores.

At the time that this depletion plan was accepted, there was only one well perforated in A Pool, in V Block. Since then, perforations have been approved in two additional blocks, BB and EE. To date, A Pool has produced 1.2 MMbbls. The production well in BB Block has recently been abandoned and production continues from EE and V Blocks.

C.2 Geological/Geophysical Model Review

There have been no reported changes to the understanding of the A Pool geological/geophysical model since the January 2009 decision regarding condition 97.01.1. In that decision the Board stated:

> A geological model was constructed by the Proponent for the A Pool evaluation. This model indicated possible geological trends and reservoir distribution but did not adequately account for reserves in thin reservoir units. Consequently, in-place volumes (STOOIP) were estimated by the Proponent on a block-by-block basis, to account for thinner reservoirs. Board staff has completed a similar analysis for

blocks with independent petrophysical analysis and concur with the Proponent's methodology. For the remaining blocks, Board staff reviewed the Proponent's overall estimates (21.4 MMm^3 or 134.6 MMbbls) and concur with their analysis after re-evaluation of thinner A Pool beds and thicker B Pool beds.

Board staff reviewed the petrophysical methodology and concur with the Proponent's analysis, but noted that the petrophysical cut-offs used to calculate A Pool's net pay have an uncertainty because of the thinness of the reservoirs. These cut-offs should be re-evaluated as the reservoir from A Pool is produced. These reserve estimates must be reviewed and updated whenever production data indicates differences to the assumptions.

C.3 Petrophysical Review

The Proponent has conducted a comprehensive logging and coring program of the Hibernia A Pool while drilling the exploration, delineation and development wells in the Hibernia field. In the document, the Proponent summarized their petrophysical interpretation for these wells. HMDC supplied supplemental information on the methodology, assumptions and criteria used in the Hibernia Formation petrophysical analysis.

Staff reviewed the petrophysical data and determined that the Proponent's interpretation of the Hibernia A Pool is similar to Staff's assessment with slight differences attributed to different methodology, assumptions and criteria used in interpreting the data. Based on its analyses, Board staff believes the interpretation presented by the Proponent in support of this application is reasonable and appropriate to evaluate this application.

C.4 STOOIP and Reserve Estimates

Currently, the Proponent estimates the STOOIP for A Pool to be 134.7 MMbbls. This estimate includes A Pool resources in the HSE Unit and the main Hibernia Field. The recovery from A Pool is expected to be 12.1 MMbbls (including condensate), with an average recovery factor of 9% (Tabl C.1).

Table C.1: Proponent's A Pool Reserve Estimate (Field Units). (Source: HMDC)

C-NLOPB Pool	Block	STOOIP (MB)	EUR Oil (MB)	EUR Cond (MB)	EUR Oil+Cond (MB)	Recovery (%)
Developed Blocks						
A1	O5	3.36	0.17	0.00	0.17	5%
A1	O5 sub	0.31	0.02	0.00	0.02	6%
A2	BB	1.09	0.06	0.00	0.06	6%
A2	V	14.31	3.58	0.04	3.62	25%
A2	CC3	0.00	0.00	0.00	0.00	--
A2	CC1	1.79	0.09	0.00	0.09	5%
A2	CC2	0.38	0.02	0.00	0.02	5%
A2	DD	0.85	0.05	0.00	0.05	6%
A2	W	4.58	0.23	0.02	0.25	5%
A2	X	1.41	0.08	0.00	0.08	6%
A2	Y	3.26	0.17	0.00	0.17	5%
A2	Z	1.21	0.07	0.00	0.07	6%
A4	EE	0.78	0.04	0.00	0.04	5%
A4	Q	0.00	0.00	0.48	0.48	--
A4	R	3.86	0.20	0.00	0.20	5%
A5	C	12.58	0.63	0.67	1.30	10%
A5	D	0.00	0.00	0.04	0.04	--
A5	D2	0.00	0.00	0.04	0.04	--
A5	F	1.07	0.06	0.08	0.14	13%
A5	B	1.32	0.07	0.09	0.16	12%
A5	G	2.52	0.13	0.25	0.38	15%
A5	H	3.02	0.16	0.00	0.16	5%
A5	I	3.48	0.18	0.04	0.22	6%
A5	J	2.88	0.15	0.00	0.15	5%
A5	K	3.51	0.18	0.00	0.18	5%
A5	L	2.59	0.13	0.08	0.21	8%
A6	A	7.81	0.40	0.26	0.66	8%
Potential Future Blocks, Included in Projected Drill Schedule						--
A1	O and O2	13.56	0.68	0.00	0.68	5%
A1	O4	2.86	0.15	0.00	0.15	5%
A3	T	3.62	0.19	0.00	0.19	5%
A4	FF	1.33	0.07	0.00	0.07	5%
A4	P	0.00	0.00	0.13	0.13	--
A4	S	0.39	0.02	0.00	0.02	5%
Potential Upside Development						
A1	P5	3.93	0.20	0.00	0.20	5%
A1	P6	6.67	0.34	0.00	0.34	5%
A5	K3	8.34	0.42	0.00	0.42	5%
A5	N	0.00	0.00	0.07	0.07	--
Blocks HSE						
A2	AA1	5.03	0.26	0.00	0.26	5%
A2	AA2	1.11	0.06	0.00	0.06	5%
A2	GG1	3.26	0.17	0.00	0.17	5%
A2	GG2	1.33	0.07	0.00	0.07	5%
A2	KK	1.59	0.08	0.00	0.08	5%
A2	LL	1.55	0.08	0.00	0.08	5%
A2	MM	1.17	0.06	0.00	0.06	5%
A2	NN	0.53	0.03	0.00	0.03	6%
A2	OO	0.44	0.03	0.00	0.03	7%
Subtotal: Developed		*77.97*	*6.87*	*2.09*	*8.96*	*11%*
Subtotal: Developed + Included in Schedule		*99.73*	*7.98*	*2.22*	*10.20*	*10%*
Subtotal: Upside Development		*18.94*	*0.96*	*0.07*	*1.03*	*5%*
Subtotal: Blocks HSE		*16.01*	*0.84*	*0.00*	*0.84*	*5%*
Total		*134.68*	*9.78*	*2.29*	*12.07*	*9%*

Note: Tables may not sum exactly because of rounding effects

There is considerable difference between the Board's STOOIP and reserves estimates and those of the Proponent. In the Board's latest Hibernia reserves assessment in 2006, STOOIP for the A Pool was estimated to be 177.2 MMbbls and reserves were estimated to be 35 MMbbls, with an average recovery factor of 20%.

As stated in the Decision Report addressing condition 97.01.1, the Board's staff feel that the Proponent's estimates for A Pool reserves (134.7 MMbbls) may be pessimistic, due to the uncertainty associated with evaluation of the A Pool. Staff feel that additional information in areas lacking development wells should be obtained in future. This is particularly significant for the O and O2 blocks, which are interpreted to be along trend with areas containing well developed A Pool sands such as the adjacent V block. Future development wells in this area will help to reduce this uncertainty and possibly increase recovery.

Gas reserves from A Pool are not included in the A Pool assessment. Gas produced from the A Pool is currently being used to support oil production as fuel gas, or by being re-injected into the gasflood region. Gas production from the Hibernia Field is discussed as a concept later under deferred development. Total gas in place in the A Pool is contained both in solution and as a gas cap in Q, C, G, I, L and A Blocks and is expected to be 290.4 GCF, as indicated in Table C.2.

Table C.2: Proponent's A Pool In-Place Volumes (Field Units). (Source: HMDC)

C-NLOPB Pool	Block	STOOIP (MB)	GIP Gas Cap (GCF)	GIP Solution (GCF)	GIP Total (GCF)
Developed Blocks					
A1	O5	3.36	0.00	4.83	4.83
A1	O5 sub	0.31	0.00	0.45	0.45
A2	BB	1.09	0.00	1.36	1.36
A2	V	14.31	1.74	20.88	22.62
A2	CC3	0.00	0.00	0.00	0.00
A2	CC1	1.79	0.00	1.22	1.22
A2	CC2	0.38	0.00	0.82	0.82
A2	DD	0.85	0.00	0.71	0.71
A2	W	4.58	0.59	6.58	7.17
A2	X	1.41	0.00	1.75	1.75
A2	Y	3.26	0.00	4.69	4.69
A2	Z	1.21	0.00	1.35	1.35
A4	EE	0.78	0.00	0.85	0.85
A4	Q	0.00	23.80	0.00	23.80
A4	R	3.86	0.00	4.60	4.60
A5	C	12.58	33.29	19.13	52.42
A5	D	0.00	1.59	0.00	1.59
A5	D2	0.00	1.64	0.00	1.64
A5	F	1.07	3.51	1.19	4.70
A5	B	1.32	4.37	2.01	6.38
A5	G	2.52	12.40	4.08	16.48
A5	H	3.02	0.00	3.34	3.34
A5	I	3.48	1.57	3.85	5.42
A5	J	2.88	0.00	4.14	4.14
A5	K	3.51	0.00	5.05	5.05
A5	L	2.59	3.97	3.72	7.69
A6	A	7.81	13.00	11.53	24.53
Potential Future Blocks, Included in Projected Drill Schedule					
A1	O and O2	13.56	0.00	19.48	19.48
A1	O4	2.86	0.00	4.11	4.11
A3	T	3.62	0.00	3.94	3.94
A4	FF	1.33	0.00	1.45	1.45
A4	P	0.00	6.22	0.00	6.22
A4	S	0.39	0.00	0.47	0.47
Potential Upside Development					
A1	P5	3.93	0.00	7.72	7.72
A1	P6	6.67	0.00	9.58	9.58
A5	K3	8.34	0.00	11.98	11.98
A5	N	0.00	3.06	0.00	3.06
Blocks HSE					
A2	AA1	5.03	0.00	5.23	5.23
A2	AA2	1.11	0.00	1.08	1.08
A2	GG1	3.26	0.00	2.24	2.24
A2	GG2	1.33	0.00	0.88	0.88
A2	KK	1.59	0.00	1.02	1.02
A2	LL	1.55	0.00	0.98	0.98
A2	MM	1.17	0.00	0.74	0.74
A2	NN	0.53	0.00	0.35	0.35
A2	OO	0.44	0.00	0.29	0.29
Subtotal: Developed		*77.97*	*101.47*	*108.13*	*209.60*
Subtotal: Developed + Included in Schedule		*99.73*	*107.69*	*137.58*	*245.27*
Subtotal: Upside Development		*18.94*	*3.06*	*29.28*	*32.34*
Subtotal: Blocks HSE		*16.01*	*0.00*	*12.81*	*12.81*
Total		*134.68*	*110.75*	*179.67*	*290.42*

In summary, Board staff view the Proponent's assessment of STOOIP and reserves in A Pool to be pessimistic. Both the Board's and the Proponent's estimates for A Pool should be reviewed as the pool is further developed.

C.5 Development Strategy

The development strategy for A Pool is a staged approach following B Pool development. A Pool is comprised mainly of thin sands with small STOOIP and limited connectivity compared to B Pool. In blocks with oil-bearing A Pool intervals, the A Pool will be perforated towards the end of production from the B Pool development well, either after the B Pool has been isolated, or commingled with B Pool production.

Board staff recognizes that because of the limited STOOIP and poor reservoir quality within A Pool, it would not be economic to develop A Pool on a stand-alone basis. The best opportunity for developing A Pool is in conjunction with B Pool development. To date, no B Pool development wells have been abandoned without the Proponent first addressing A Pool resources in the respective block. For example, in the case of B-16 13 in EE Block, the A Pool was perforated and the well remains in service producing from the A Pool. In future, the Proponent must continue to address A Pool resources before abandoning any B Pool development well.

C.6 Production Forecast

Production from A Pool is expected to be opportunistic and short-lived in the blocks that are developed. The production profile expected from A Pool is not the production profile typical of the field, with a steady build-up phase, followed by a number of years at peak production, followed by steady decline for the life of the field. Instead, production from A Pool is expected to come on sporadically, as the final uplift from B Pool development wells before they are abandoned.

According to the Proponent’s forecast, A Pool production reached its peak in 2008, when the A Pool in B-16 13 was perforated, with an average daily production of 3600 bbls/d. Additional peaks of 1800, 2100 and 2500 bbls/d are expected in 2012, 2014 and 2016. Total production from A Pool is expected to be 8.4 MMbbls, but as only three wells have been perforated in A Pool, there remains a high level of uncertainty with respect to A Pool production.

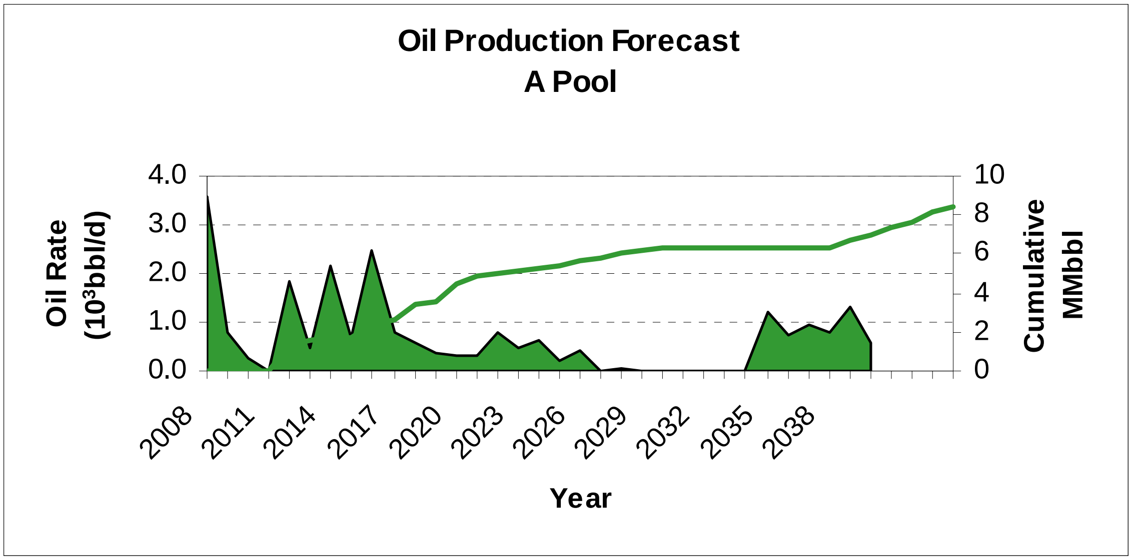


Figure C.1: A Pool Oil Production Forecast. (Source: C-NLOPB from HMDC)

Gas production from A Pool is expected to be produced from solution, and to closely follow the oil production trend. Like oil production, gas production peaked in 2008, with additional peaks expected in 2012, 2014 and 2016. A Pool is forecasted to produce 12.0 GCF of gas over its field life. Figure C.2 shows the historical and forecasted gas production from the Hibernia A Pool.

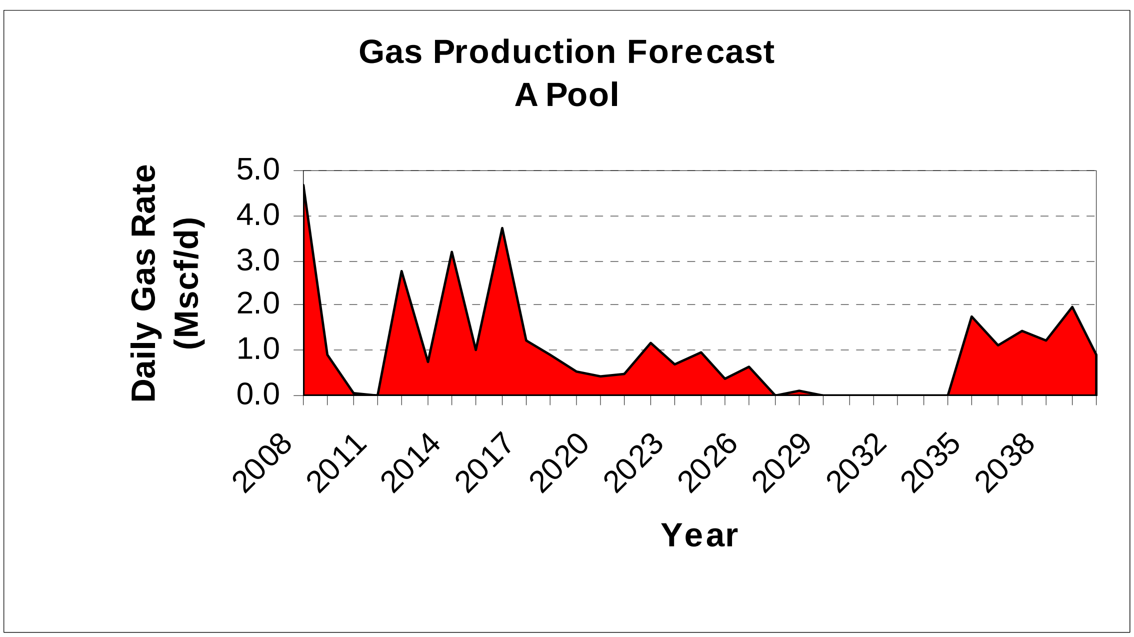


Figure C.2: Pool Gas Production Forecast. (Source: C-NLOPB from HMDC)

Water production from A Pool is expected to peak in 2014 with an average water production rate of 3200 bbls/d. At the time of peak water production, A Pool will be producing less than 2% of the total Hibernia water production, and it will have little to no impact on water management on the Hibernia Platform. Figure C.3 shows the historical and forecasted water production from the Hibernia A Pool.

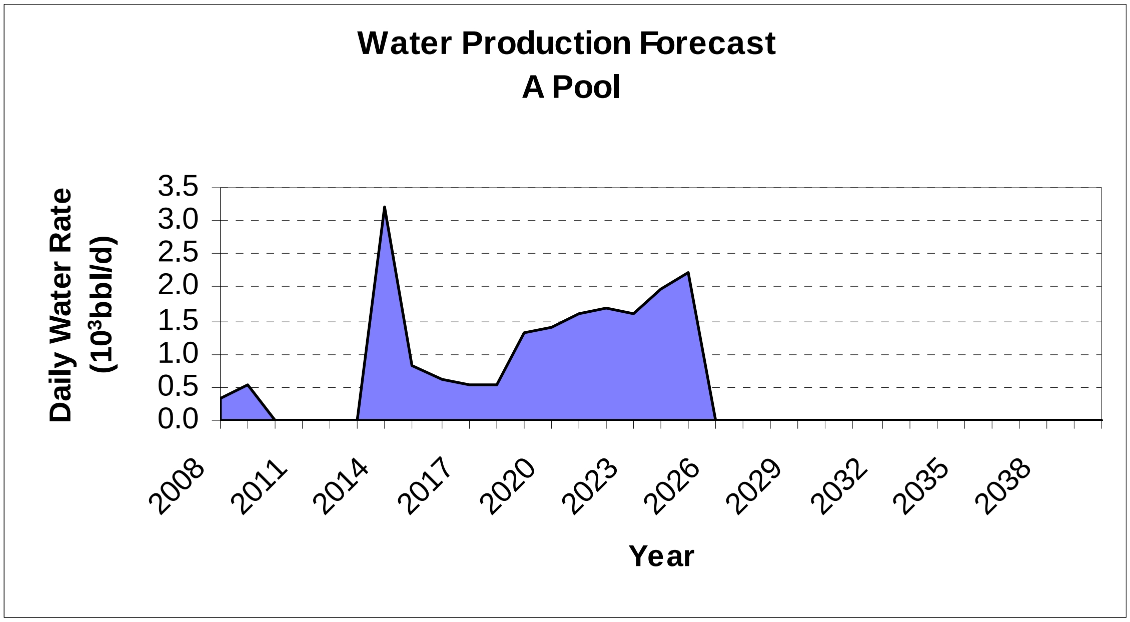


Figure C.3: A Pool Water Production Forecast. (Source: C-NLOPB from HMDC)

Upon review of the oil, gas and water production forecasts for the Hibernia A Pool, Board staff feel that the production forecast for the A Pool field life is reasonable. However, Board staff recognizes that the A Pool is at an early stage of its development life, and as more A Pool intervals are opened up, data collected will be incorporated into models to improve understanding of the A Pool.

C.7 Development of the A Pool Within the Context of Hibernia Full Field

Although the resources in A Pool are relatively small compared to those in other areas of the Hibernia Field, the exploitation of those resources must be addressed before any block can be abandoned. All reasonable effort must be made by the Proponent to extract resources from A Pool to prevent waste. Individual slots will not be considered for reclamation unless A Pool resources have been addressed.

In the context of the Hibernia Field, oil, gas and water production from A Pool is small and will not have significant impact on the platform facilities.

C.8 Conclusions

- The Proponent’s best estimates of STOOIP volumes [134.7 MMbbls of oil and 290.4 GCF of gas] are considered possible.

- The Proponent’s recovery factor (9%) is less then the Board’s recovery factor (16%). This difference will continue to be evaluated as development of the A Pool progresses.

- Based on a review of geological, geophysical, petrophysical and reservoir engineering data, staff concur with the Proponent that using existing B Pool wellbores is appropriate, and decisions on isolation of the A Pool or commingling production with the B Pool will continue to be made on a case-by-case basis.

- Resource Management staff have concluded that no significant changes to the Hibernia main field A Pool reservoir development are necessary. Development of A Pool will continue to be evaluated as more drilling and production data is acquired. A Pool development will not be adversely affected by the addition of the HSE Unit.

Appendix D

Hibernia AA Blocks

D.1 Hibernia AA Blocks

The Hibernia AA Blocks are located in the southern portion of the Hibernia Field, north of the HSE Unit, and are located entirely within PL1001. Originally, the AA Blocks were considered part of Hibernia South; however, approval to develop AA Blocks was addressed separately in a Development Plan Amendment submitted by the Proponent in June 2009, and approved by the Board in August of that year. Since then, an oil producer and water injector have been drilled in AA1 Block, and an oil producer has been drilled in the AA2 Block. The drilling of a water injector in AA2 Block is ongoing. First oil from the AA Block occurred in November of 2009.

D.2 Geological/Geophysical Model Review

The Board's staff reviewed the portion of the Proponent's geological model pertaining to the AA Blocks in the Application. At the time of submission, well data from AA Block was not yet available to be incorporated into the Proponent's Petrel model; however, log data from three AA Block wells, B-16 57X, B-16 37Z and B-16 5Z, has since been analyzed by Board staff as part of this review.

The lithologies, facies, reservoir connectivity and continuity were anticipated by the Proponent to be similar what has been encountered in the Hibernia B Pool throughout the field, although some degradation of reservoir quality with depth was expected. Log data from the three AA Block wells that have been drilled to date confirm similar lithologies, facies and reservoir distribution to Hibernia B Pool reservoir occurrences in the main part of the field. As expected, the AA Blocks do show minor degradation in reservoir quality when compared with the crest of the field, nevertheless, all three wells encountered high quality, oil-saturated sandstone reservoirs. As predicted in the 2009 DPA submission, no oil-water contact was encountered by drilling in the AA Blocks, as these structurally high fault blocks are located above the minimum anticipated oil-down-to depth of 4600 m TVDss.

D.3 STOOIP and Reserve Estimates

There have been no changes to the Proponent's nor the Board's STOOIP and reserve estimates for the AA Blocks since the approval of the June 2009 DPA.

The Proponent's and the Board's geological models for the Hibernia reservoir are similar. Since the geological models use similar well defined structural surfaces, fluid contacts and well data, both provide comparable oil-in-place estimates, as seen in Table D.1.

Table D.1 : Proponent's 2006, 2009/2010 and C-NLOPB's Hibernia AA Block B Pool Reserves Estimate Summary (Field Units). (Source: HMDC and C-NLOPB)

	Hibernia AA Block Most Likely Oil Reserves Estimate								
	HMDC (2006)			HMDC (2009/2010)			C-NLOPB (2006)		
	STOOIP (MMbbls)	Reserves (MMbbls)	Recovery Factor	STOOIP (MMbbls)	Reserves (MMbbls)	Recovery Factor	STOOIP (MMbbls)	Reserves (MMbbls)	Recovery Factor
Total	**103**	**54**	**52%**	**117**	**48.5**	**41%**	**124.7**	**48**	**40%**

The Proponent updated its STOOIP and reserves estimates from 2006 in its 2009 DPA. Best estimate in-place hydrocarbon volumes for Hibernia AA Blocks are 117 MMbbls of oil and 119 GCF of gas. STOOIP estimates have increased by 14% and reserves have decreased by 11%.

It should be noted that STOOIP and reserves estimates in the Proponent's 2009 Application are closer to the Board's estimates, which have not changed since 2006. Both estimates use a recovery factor of approximately 40%. Board staff appreciate that there is a certain degree of uncertainty surrounding these estimates, which will be further refined as production continues in the AA Blocks.

The Proponent's upside reserves estimate is 69.8 MMbbls (58%), which is very close to the Board's upside estimate of 70 MMbbls (56% recovery). The Proponent's downside reserve estimate of 37 MMbbls (31% recovery) is somewhat higher than the Board's estimate of 32 MMbbls (25% recovery). All of these estimates are dependent upon reservoir quality, which may improve or degrade depending upon diagenetic factors related to burial history.

The Proponent's distribution of oil and gas reserves in the Hibernia AA Blocks is detailed in Table D.2 below.

Table D.2: Hibernia AA Blocks B Pool Original In-Place Volumes (Field Units). (Source: HMDC)

C-NLOPB Sub-Pool	Block	Oil STOOIP (MB)	GIP Free Gas (GCF)	GIP Solution (GCF)	Total GIP (GCF)
Developed Blocks					
Potential Future Blocks, included in Drill Schedule					
B2	AA1	82.0	0.0	85.1	85.1
B2	AA2	35.0	0.0	33.8	33.8
Upside Development (Volume assumes best estimate OWC)					
Subtotal: Developed		*0.0*	*0.0*	*0.0*	*0.0*
Subtotal: Developed in Schedule		*117.0*	*0.0*	*118.9*	*118.9*
Subtotal: Upside Development		*0.0*	*0.0*	*0.0*	*0.0*
Total AA Blocks		*117.0*	*0.0*	*118.9*	*118.9*

The Board's staff concurs with the reserve estimate provided by the Proponent for the Hibernia AA Blocks.

D.4 Development Strategy

The Proponent continues to follow the development strategy proposed in the June 2009 DPA. Board staff approved the Proponent's depletion plan for the Hibernia AA1 and AA2 fault blocks (Figure D.1).

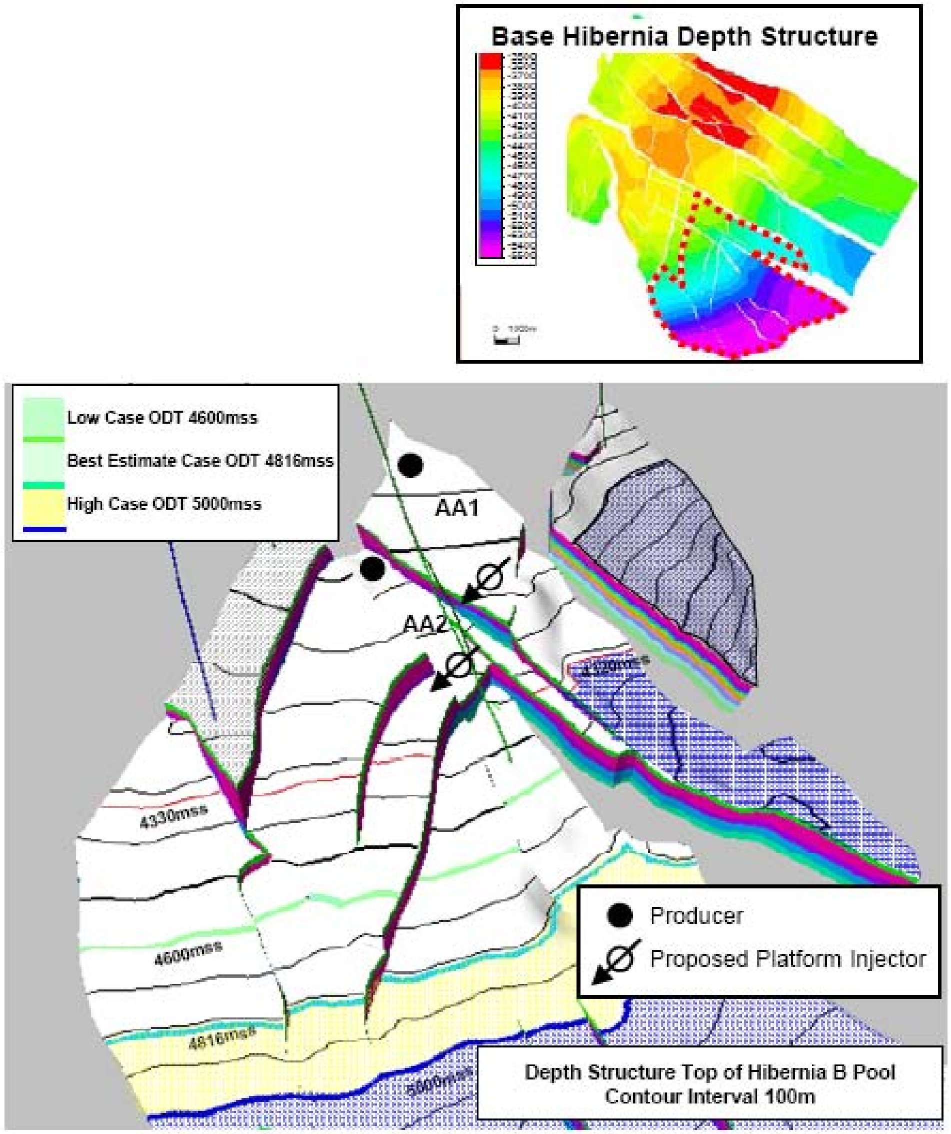


Figure D.1: Proposed Hibernia AA Blocks Development. (Source: Modified from HMDC)

The Proponent is developing the AA Blocks through waterflood, in the same manner as the Hibernia B Pool main field development. The depletion scheme for the AA Blocks includes drilling two oil production wells and two water injection wells from the GBS platform (Figure D.1).

Based on a review of geological, geophysical, petrophysical and reservoir engineering data, staff agree with the Proponent that the proposed waterflood and exploitation strategies are reasonable. Waterflood is effective in other areas of the Hibernia reservoir that have similar characteristics to the AA Blocks. Drilling and production data acquired since the approval of the June 2009 DPA appear to confirm that this depletion scheme is appropriate for the AA Blocks.

D.5 Production Forecast

The Board's staff reviewed the oil production forecasts provided by the Proponent for the AA Blocks. Production from the AA Blocks began in 2009 and is expected to peak in 2012 with an average daily production of 25,200 bbls/d. Following this peak, production is expected to decline until 2025, to a rate of 500 bbls/d when the wells are abandoned. In total, AA Blocks are expected to produce 48.4 MMbbls over the life of the field. Figure D.2 shows the forecasted oil production from the Hibernia AA Blocks.

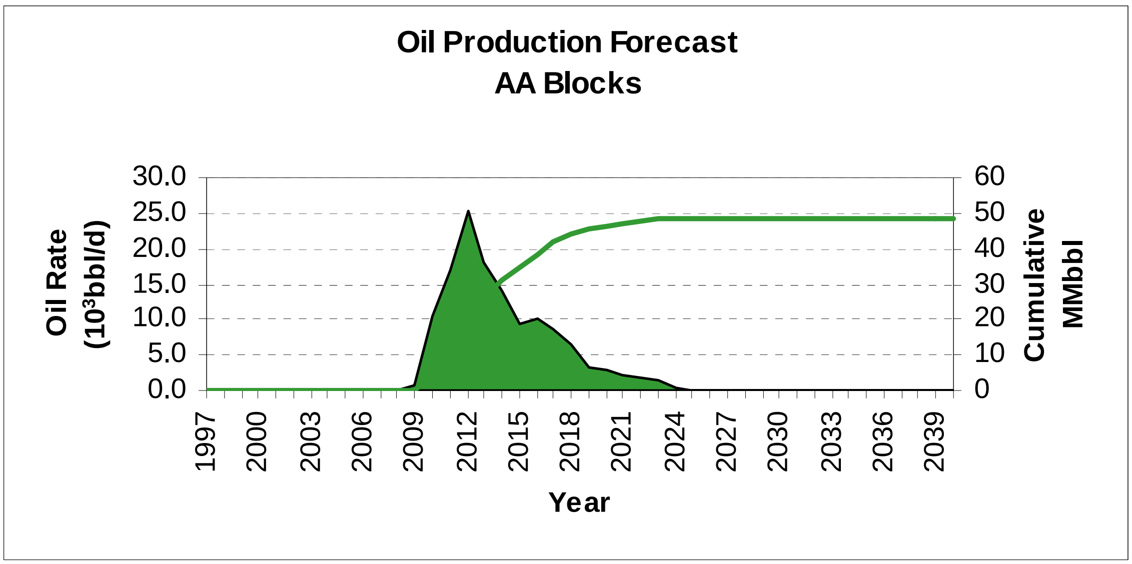


Figure D.2: Oil Production Forecast for AA Blocks. (Source: C-NLOPB from HMDC)

Gas production from the AA Blocks is expected to closely follow oil production and is anticipated to peak in 2012 with a production rate of 21.6 MMscf/d. Over the field life, AA Blocks are expected to produce 40.9 GCF of gas, which will be used for re-injection into the gasflood region. Figure D.3 shows the forecasted gas production from the Hibernia AA Blocks.

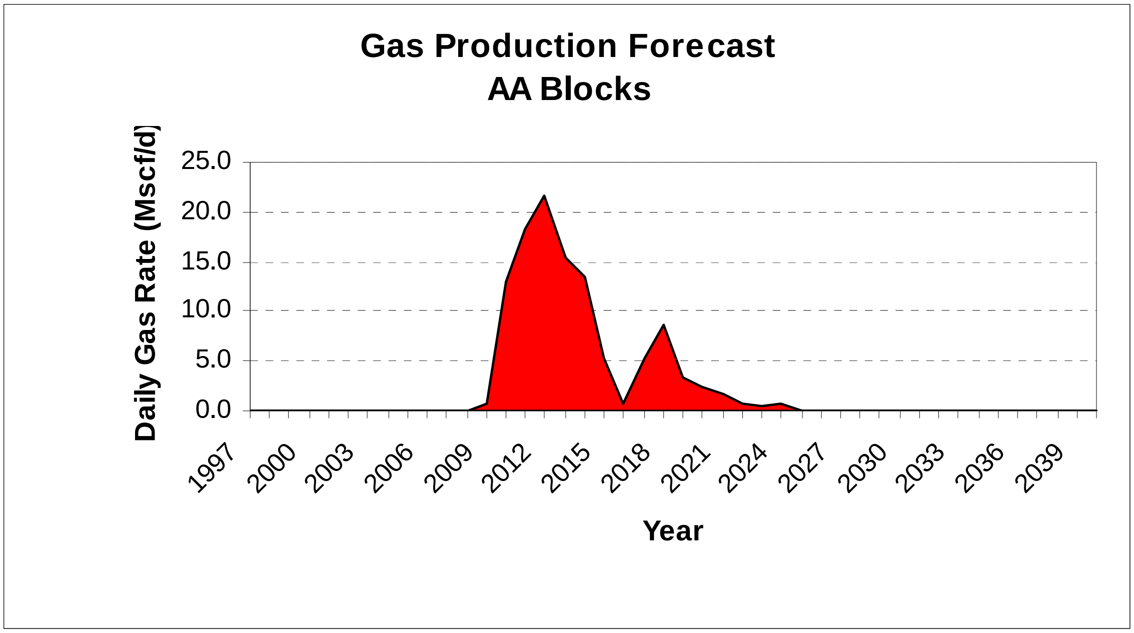


Figure D.3: Gas Production Forecast for AA Blocks. (Source: C-NLOPB from HMDC)

Water production from the AA Blocks is expected to peak in 2015 with an average daily water production rate of 28,800 bbls/d of water. At that time, the AA Block will account for 22% of water produced from the Hibernia Field. Following a slight drop in 2017 and 2018, water production is expected to remain steady at approximately 25,000 bbls/d for the remainder of the blocks' production life. Figure D.4 shows the forecasted water production from the Hibernia AA Blocks.

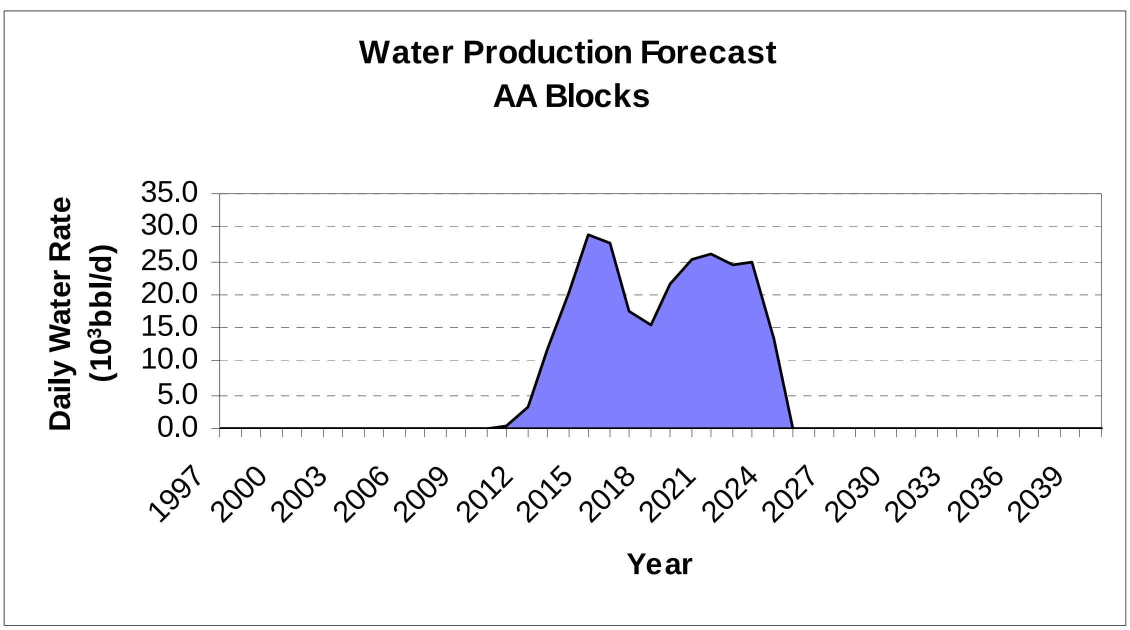


Figure D.4: Water Production Forecast for AA Blocks. (Source: C-NLOPB from HMDC)

Upon review of the oil, gas and water production forecasts for the AA Blocks, Board staff feel that the production forecast for the AA Blocks' field life is reasonable.

D.6 Development of the AA Blocks Within the Context of Hibernia Full Field

Board staff considered the AA Blocks development in the context of its impact on the overall Hibernia Field development, including opportunities within pools and reservoirs already under development. Staff has determined that development of the HSE Unit will not negatively impact the development of the AA Blocks.

D.7 Conclusions

- Drilling of the first producer/injector pair has yielded positive results. Production from AA1 Block has been steady. Analysis indicates that no changes need to be made to the interpretation presented in the June 2009 DPA.

- Resource Management staff have concluded that no significant changes to the AA Blocks reservoir development are necessary. The AA Blocks development will not be adversely affected by the addition of the HSE Unit.

Appendix E

Ben Nevis-Avalon Reservoir

E.1 Ben Nevis-Avalon Reservoir

Production from the Ben Nevis-Avalon (BNA) reservoir began in 2000. It is a complex reservoir with a high degree of faulting and compartmentalization. In the past, the BNA has accounted for about 5% of the daily production from the Hibernia Field. In 2009, BNA production rose to an average of 17,248 bbls/d, about 14% of total field production. As of April 2010 the BNA has produced 38.7 MMbbls of oil and has accounted for 5.6% of Hibernia's production. Following a pilot scheme to assess production characteristics in the northwest portion of the reservoir, the Board approved the Development Plan Amendment for the Ben Nevis-Avalon reservoir in January 2006 (Decision 2006.01).

E.2 Geological/Geophysical Model Review

Because there have been no significant changes in the Proponent's geological interpretation of the BNA reservoir, no new Petrel geological model for the BNA was submitted in support of this Application. Board staff have reviewed the most recent model submission (received May 2009) and the geological data provided in the Application, and find the outcomes to be reasonable interpretations.

The Proponent has changed its naming scheme for the structural fault blocks within the BNA reservoir compared with previous submissions. Figure E.1 provides the updated block and sub-block names.

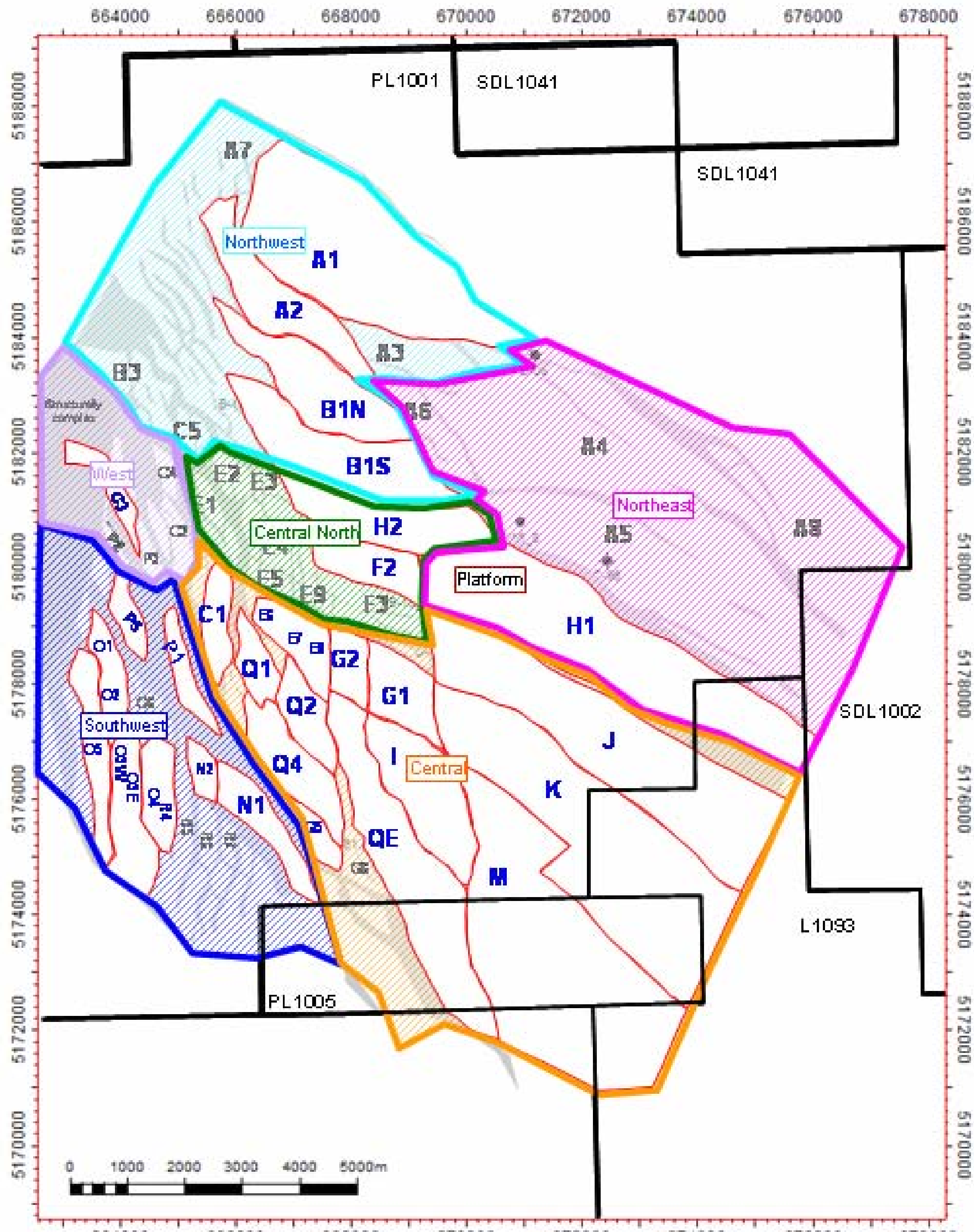


Figure E.1: Map on Base of LBN1 Reservoir, Indicating Fault Blocks, Sub-blocks, and Sectors Used for STOOIP Assessment. (Source: HMDC)

The part of the BNA reservoir defined by the Proponent as the Hibernia South Extension (HSE) Unit area is illustrated in Figure E.2 below.

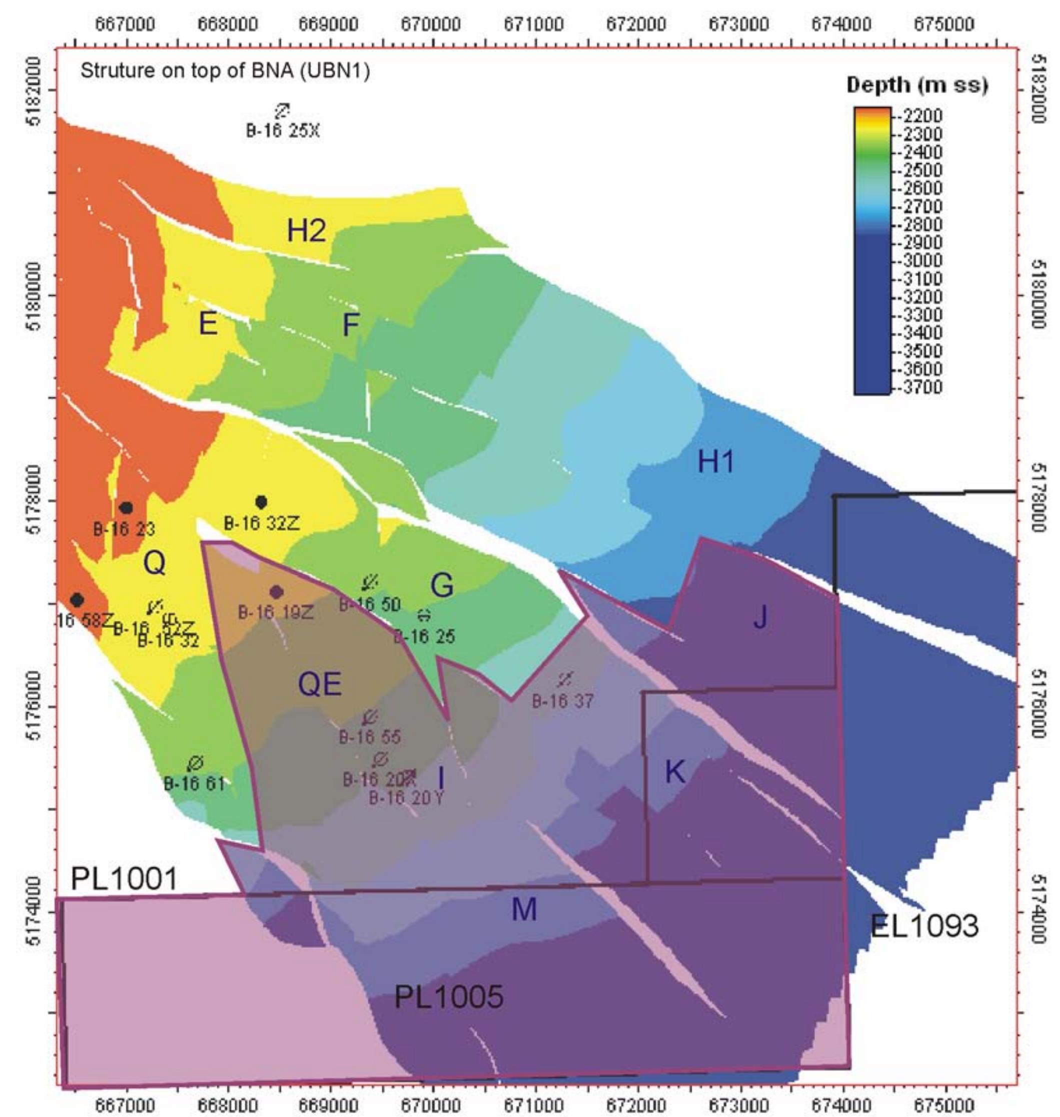


Figure E.2: Map Showing Approximate Boundaries of the HSE Unit for the BNA Reservoir, Shaded in Purple. (Source: C-NLOPB from HMDC)

The BNA formations at Hibernia contain a number of sandstone units, of which LBN1, LBN3 and UBN1 are considered the most prospective reservoir intervals. Since submission of the Application, three new development wells have been drilled in the Hibernia AA Block, and these intersect the BNA H1 and J Blocks in updip positions. These wells encountered thinner sandstones in the BNA interval, with low net pay compared to existing BNA development wells in the main part of the field.

According to the Application, the Proponent plans to develop BNA LBN3 and UBN1 reservoirs of the I/M and QE Blocks within the HSE Unit, and several other blocks in the HSE Unit are listed as upside potential. Because the LBN1 sandstone is well developed in the southernmost existing wells, e.g. B-16 20X and B-16 20Y, Board staff expect that any new BNA development wells in the HSE Unit will penetrate the full depth of the BNA interval in order to assess reservoir quality and potential of the full formation.

E.3 Petrophysical Review

The Proponent has conducted a comprehensive logging and coring program of the Ben Nevis-Avalon reservoir while drilling the exploration, delineation and development wells in the Hibernia field. In the Application, the Proponent summarized their petrophysical interpretation for these wells. HMDC supplied supplemental information on the methodology, assumptions and criteria used in the BNA petrophysical analysis.

Staff reviewed the petrophysical data and determined that the Proponent's interpretation of the Ben Nevis-Avalon reservoir is similar to Staff's assessment with slight differences attributed to different methodology, assumptions and criteria used in interpreting the data. Based on its analyses, Board staff believes the interpretation presented by the Proponent in support of this application is reasonable and appropriate to evaluate this application.

According to the Application, a uniform BNA oil-water contact at 3042 TVDss is predicted across the field, with some minor variations. One exception is the K Block, which has a shallower oil-water contact, resulting from either hydraulic isolation from the remainder of the field, or from communication across non-sealing faults due to production in the adjacent I Block. J Block, previously interpreted as an isolated block, is now believed to be connected to the central area.

E.4 STOOIP and Reserve Estimates

The Proponent has made some changes to the STOOIP and reserves estimates for the BNA reservoir since the June 2009 DPA was approved. The overall STOOIP for the BNA of 1538.6 MMbbls has remained unchanged; however, there are some changes in the drilling schedule, and specifically what is considered upside development.

In the June 2009 DPA, STOOIP for the BNA was estimated to be 459.7 MMbbls including areas that were developed or scheduled to be developed. In the current Application, STOOIP has been reduced to 383.0 MMbbls. This reduction is not due to any change in the geological interpretation, but rather due to the O3, H1 (up-dip) and J (up-dip) blocks being moved from the drill schedule to potential upside development. While STOOIP in the developed and scheduled blocks has gone down overall, estimated ultimate recovery from this area has increased. This is due to an increase in expected recovery from the developed area. In the June 2009 DPA, the recovery factor in the developed area was 28%. In this Application, the recovery factor in the developed area in now expected to be 37%. Estimated ultimate recovery has been increased from 123.5 MMbbls to 135.2 MMbbls.

The Proponent has listed significant STOOIP volumes in blocks that are considered to be upside development. The STOOIP in these blocks totals 1155.6 MMbbls, but the estimated recovery is 114.2 MMbbls, with a recovery factor of 10%. The recovery estimate from these blocks is low due to the heavily faulted nature of the BNA reservoir. The Proponent has indicated that one of the key mechanisms to allow development of upside potential in the BNA is future advances in drilling technology, specifically multi-target drilling to allow smaller fault blocks to become economically viable through shared drilling costs.

Volume estimates for the BNA in the HSE Unit area have been included in the full-field estimates quoted above. Of the 135.2 MMbbls most likely case, 26.7 MMbbls is expected to come from the I/M and QE Blocks within the HSE Unit. An additional 5.2 MMbbls is expected from the HSE Unit area in the upside development case, with upside potential recognized in the K South, J (down-dip), I/M and K (down-dip) blocks.

The total estimated recovery for the BNA reservoir, including the developed area, blocks included in the drilling schedule and upside development, is 249.4 MMbbls. This is an increase from the 237.2 MMbbls estimated in the June 2009 DPA. The Proponent’s STOOIP and reserves estimates for the BNA reservoir are included in Table E.1.

Table E.1: Proponent's BNA Oil STOOIP and Reserves Estimates (Field Units). (Source: HMDC)

C-NLOPB Pool	Block	Assessment Sector	STOOIP (MB)	EUR (MB)	Recovery (% STOOIP)
Developed Blocks					
B3	Q2 Block	Central	48.4	20.7	43%
B3	I Block (LBN1 Only)	Central	35.4	12.9	37%
B4	B1 South Block	NW	46.0	16.1	35%
B3	G1 Block	Central	23.9	10.0	42%
B3	K Block (LBN1 Only)	Central	27.7	8.0	29%
B2	N1 Block	SW	22.9	11.5	50%
B3	Q4	Central	47.7	14.7	31%
Potential Future Blocks, Included in Drill Schedule					
B3	G2	Central	17.4	10.0	57%
Potential Future Blocks (partially in PL1005 or EL1093), Included in Drill Schedule					
B3	I/M (LBN3&UBN1)	Central (Non HSE Ut)	13.7	4.5	33%
B3	I/M (LBN3&UBN1)	Central (HSE Unit)	44.6	14.7	33%
B3	QE (LBN3&UBN1)	Central (HSE Unit)	55.4	12.0	22%
Potential Upside Development					
B1	O3 (west+east)	SW	54.1	15.6	29%
B3	H1 (up-dip)	NE	17.0	6.6	39%
B4	B1N	NW	32.8	6.0	18%
B2	N2	SW	16.3	3.0	18%
B3	E06-E08	Central	27.5	5.1	18%
B6	A1	NW	54.8	5.5	10%
B2	O1	SW	26.6	4.9	18%
B5	O4	SW	25.5	4.7	18%
A1/B3	C1	Central	29.6	5.5	18%
B2	P5	SW	22.9	4.2	18%
B3	H2	Central North	20.7	2.1	10%
B6	A2	NW	24.8	2.5	10%
B2,C1	P1	SW	33.1	3.3	10%
B1	O5	SW	18.9	1.9	10%
B2,C1	C3	West	18.8	1.9	10%
B3	Q1	Central	17.2	1.7	10%
B3	Q5	Central	10.9	1.1	10%
B3	F2	Central North	18.4	1.8	10%
B3	Central Subblocks	Central	133.2	6.7	5%
B1	SW Subblocks	SW	132.1	6.6	5%
B2	West Subblocks	West	109.7	5.5	5%
B6	NW Subblocks	NW	78.1	3.9	5%
B3	North-Central Subblocks	Central North	99.0	5.0	5%
B5	NE Subblocks	NE	20.4	1.0	5%
Potential Upside Development (partially in PL1005 or EL1093)					
B3	Central Subblock (K South)	Central (HSE Unit)	20.3	1.0	5%
B3	H1 (down-dip)	NE	21.6	2.2	10%
B3	J (down-dip)	Central (HSE Unit)	28.0	2.8	10%
B3	I/M (LBN2&LBN1)	Central	4.3	0.2	5%
B3	I/M (LBN2&LBN1)	Central (HSE Unit)	14.0	0.7	5%
B3	K (down-dip)	Central (HSE Unit)	14.5	0.7	5%
B3	QE (LBN2&LBN1)	Central	4.6	0.2	5%
B3	J (up-dip)	Central	5.7	0.3	5%
Subtotal: Developed			251.9	94.0	37%
Subtotal: Developed + Included in Schedule			383.0	135.2	35%
Subtotal: Upside Development			1155.6	114.2	10%
Total BNA (Non HSE Unit)			1361.8	217.4	16%
Total BNA (HSE Unit)			176.7	32.0	18%
Total			1538.6	249.4	16%

The Board's current reserves estimate for the BNA reservoir is 182 MMbbls. This is based on an estimated STOOIP of 1820 MMbbls and an average recovery factor of 10%. After reviewing the Proponent’s most likely estimated recovery of 135.2 MMbbls with a potential upside of 249.4 MMbbls, Board staff believe that the Proponent’s estimates are reasonable.

Gas reserves from the BNA are not included in the assessment, but gas production from the Hibernia Field is discussed as a concept under deferred development. Total gas-in-place in the BNA is expected to be contained entirely in solution, and is expected to be 181.6 GCF in the developed and scheduled areas, and 599.2 GCF in upside development areas. Gas produced from the BNA reservoir is currently handled with all other gas produced from the Hibernia Platform, and is either flared, used as fuel or injected into the gasflood region. Oil and gas resources in the BNA reservoir are presented in Table E.2.

Table E.2: Proponent's BNA In-Place Volumes (Field Units). (Source: HMDC)

C-NLOPB Pool	Block	Assessment Sector	STOOIP (MB)	GIP Free Gas (GCF)	GIP Solution (GCF)	Total GIP (GCF)
Developed Blocks						
B3	Q2 Block	Central	48.4	0.0	31.1	31.1
B3	I Block (LBN1 Only)	Central	35.4	0.0	18.9	18.9
B4	B1 South Block	NW	46.0	0.0	30.5	30.5
B3	G1 Block	Central	23.9	0.0	13.0	13.0
B3	K Block (LBN1 Only)	Central	27.7	0.0	7.0	7.0
B2	N1 Block	SW	22.9	0.0	8.2	8.2
B3	Q4	Central	47.7	0.0	30.7	30.7
Potential Future Blocks, Included in Drill Schedule						
B3	G2	Central	17.4	0.0	9.5	9.5
Potential Future Blocks (partially in PL1005 or EL1093), Included in Drill Schedule						
B3	I/M (LBN3&UBN1)	Central (Non HSE Ut)	13.7	0.0	4.4	4.4
B3	**I/M (LBN3&UBN1)**	**Central (HSE Unit)**	**44.6**	**0.0**	**14.4**	**14.4**
B3	**QE (LBN3&UBN1)**	**Central (HSE Unit)**	**55.4**	**0.0**	**13.9**	**13.9**
Potential Upside Development						
B1	O3 (west+east)	SW	54.1	0.0	18.2	18.2
B3	H1 (up-dip)	NE	17.0	0.0	10.8	10.8
B4	B1N	NW	32.8	0.0	21.7	21.7
B2	N2	SW	16.3	0.0	5.8	5.8
B3	E06-E08	Central	27.5	0.0	15.0	15.0
B6	A1	NW	54.8	0.0	35.1	35.1
B2	O1	SW	26.6	0.0	16.0	16.0
B5	O4	SW	25.5	0.0	8.6	8.6
A1/B3	C1	Central	29.6	0.0	19.3	19.3
B2	P5	SW	22.9	0.0	13.8	13.8
B3	H2	Central North	20.7	0.0	13.3	13.3
B6	A2	NW	24.8	0.0	15.9	15.9
B2,C1	P1	SW	33.1	0.0	20.0	20.0
B1	O5	SW	18.9	0.0	6.4	6.4
B2,C1	C3	West	18.8	0.0	11.4	11.4
B3	Q1	Central	17.2	0.0	11.1	11.1
B3	Q5	Central	10.9	0.0	7.0	7.0
B3	F2	Central North	18.4	0.0	11.9	11.9
B3	Central Subblocks	Central	133.2	0.0	56.1	56.1
B1	SW Subblocks	SW	132.1	0.0	44.5	44.5
B2	West Subblocks	West	109.7	0.0	66.2	66.2
B6	NW Subblocks	NW	78.1	0.0	51.7	51.7
B3	North-Central Subblocks	Central North	99.0	0.0	63.9	63.9
B5	NE Subblocks	NE	20.4	0.0	12.9	12.9
Potential Upside Development (partially in PL1005 or EL1093)						
B3	**Central Subblock (K South)**	**Central (HSE Unit)**	**20.3**	**0.0**	**8.5**	**8.5**
B3	H1 (down-dip)	NE	21.6	0.0	13.7	13.7
B3	**J (down-dip)**	**Central (HSE Unit)**	**28.0**	**0.0**	**7.1**	**7.1**
B3	I/M (LBN2&LBN1)	Central	4.3	0.0	1.7	1.7
B3	**I/M (LBN2&LBN1)**	**Central (HSE Unit)**	**14.0**	**0.0**	**5.4**	**5.4**
B3	**K (down-dip)**	**Central (HSE Unit)**	**14.5**	**0.0**	**3.6**	**3.6**
B3	QE (LBN2&LBN1)	Central	4.6	0.0	1.2	1.2
B3	J (up-dip)	Central	5.7	0.0	1.4	1.4
Subtotal: Developed			251.9	0.0	139.4	139.4
Subtotal: Developed + Included in Schedule			383.0	0.0	181.6	181.6
Subtotal: Upside Development			1155.6	0.0	599.2	599.2
Total BNA (Non HSE Unit)			1361.8	0.0	727.9	727.9
Total BNA (HSE Unit)			**176.7**	**0.0**	**53.0**	**53.0**
Total			**1538.6**	**0.0**	**780.8**	**780.8**

E.5 Development Strategy

Development of this reservoir has been a deferred development to the main Hibernia B Pool reservoir. There have been 15 development wells drilled in the BNA reservoir, including six oil producers and nine water injectors. Three of these water injectors are dual water injectors.

Development wells in the BNA reservoir, while not as productive as Hibernia reservoir development wells, are capable of individual production rates up to 10,000 bbls/d (1590 m^3/d).

Water injection into this reservoir has proven to be a challenge, largely due to poor reservoir quality, stratigraphic uncertainty and complex faulting. Developed fault blocks must also address difficulties associated with sand production.

While this reservoir has proven challenging to produce, the Board's staff has always maintained that there is significant upside potential. In 2006, the Proponent put forward a phased development plan that considered the BNA reservoir in all areas of the field. Staff agree with this phased approach as it is deemed the most appropriate balance to capture recoverable oil with mitigation of risk due to structural and stratigraphic complexity. BNA production has increased in the last two years, largely due to the Proponent's implementation of this approach.

E.6 Reservoir Simulation Model

As previously discussed, the Hibernia full-field model used to prepare the Application is comprised of six sector models controlled by a set of Well Management Logic. Both the Well Management Logic and the reservoir simulator EM^{Power} are proprietary to the Proponent. The Hibernia sector models that include the BNA reservoir are the Central (IQK) Simulation and a simplified model to represent future BNA development. According to the Application, the simplified model represents fault blocks as material balance tanks to allow future opportunities to be captured in the combined development plan for the field.

Board staff have determined that this approach to reservoir simulation is appropriate given the uncertainty that exists in the BNA reservoir; however, as development advances, a more representative model will be required. Board staff will continue to look for updates to the BNA Reservoir Simulation Model in the Annual Resource Management Plan update.

E.7 Production Forecast

The Board's staff reviewed the oil production forecast provided by the Proponent for the BNA. Production from the BNA began in 2000 and is expected to peak in 2014 with an average production of 18,300 bbls/d. As production in the BNA has taken a more staged approach, the production plateau is expected to be longer than that of B Pool, and the decline less sharp. Figure E.3 shows the historical and forecasted production from the BNA reservoir.

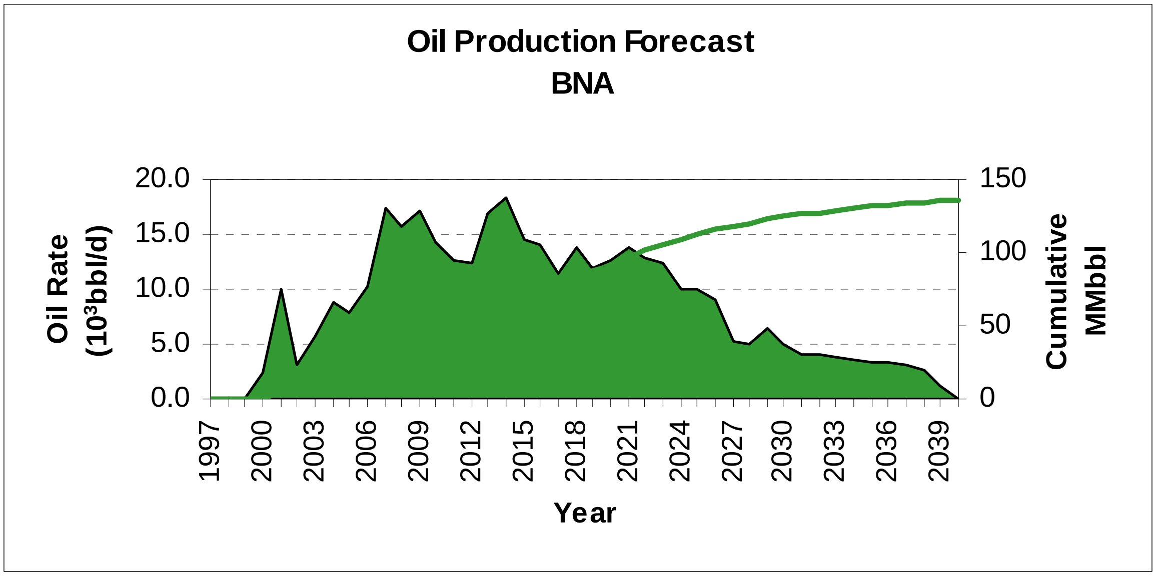


Figure E.3: BNA Oil Production Forecast. (Source: C-NLOPB from HMDC)

Gas production from the BNA reached a peak of 9.4 MMscf/d in 2009. Gas from the BNA is produced out of solution as oil is produced. As oil production declines, gas production is also expected to decline. As with all gas produced on the Hibernia Platform, gas from the BNA is, for the most part, re-injected into the B Pool gasflood region. Figure E.4 shows the historical and forecasted gas production from the BNA reservoir.

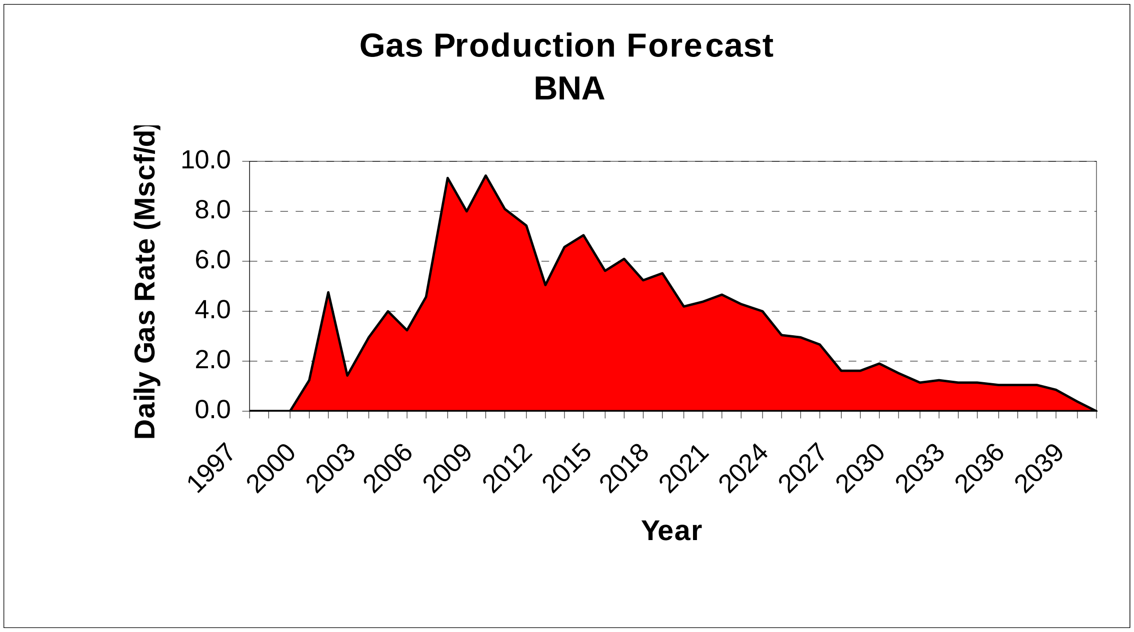


Figure E.4: BNA Gas Production Forecast. (Source: C-NLOPB from HMDC)

Water production from the BNA reservoir is expected to peak in 2023 with an average water production rate of 36,500 bbls/d. Water production is forecasted to remain relatively steady in the later years of the field development, at around 23,000 bbls/d. Figure E.5 shows the historical and forecasted water production from the BNA reservoir.

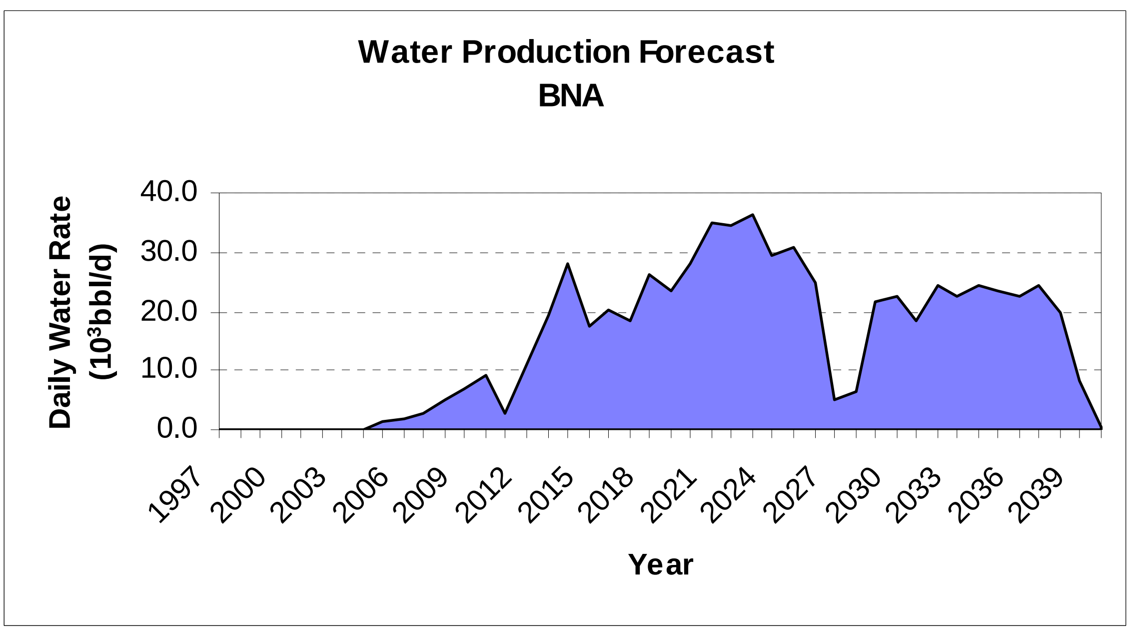


Figure E.5: BNA Water Production Forecast. (Source: C-NLOPB from HMDC)

Upon review of the oil, gas and water production forecast for the BNA reservoir, Board staff believe that the production forecast for the BNA field life is reasonable.

E.8 Development of the BNA Within the Context of Hibernia Full Field

Although there has been limited production from the BNA reservoir, recent success in the northwest wedge, as part of the phased development approach, could progress to other areas of the BNA reservoir. STOOIP and recovery efficiencies are improving, providing optimism that the lessons learned can be applied to undeveloped areas, thus leading to increased recovery and more widespread development of the resource. Over the life of the field, reclaimed slots may be used to develop the upside potential contained in this reservoir.

Board staff are encouraged by the Proponent's increased effort into developing the BNA and look forward to assessing the progress of this development in the Annual Resource Management Plan.

E.9 Conclusions and Recommendations

- The Proponent's best estimates of STOOIP volumes [1538.6 MMbbls (244.6 MMm^3) of oil and 780.8 GCF (22.1 Gm^3) of gas] are considered reasonable.
- The Proponent's overall recovery factor (15%) is consistent with Board's estimate.
- The Proponent's expected production forecast will reach a maximum of 19,300 bbls/d with an estimated cumulative production of 135.2 MMbbls.
- Resource Management staff have concluded that no significant changes to the Ben Nevis-Avalon reservoir development are necessary. BNA development will not be adversely affected by the addition of the HSE Unit.

Appendix F

Catalina Member

F.1 Catalina Member

The Catalina Member of the Whiterose Formation is a series of interbedded sandstones and shales present in the crestal region of the Hibernia Field. Porous oil and gas bearing sandstones exist within the Catalina Member, but are generally thinly bedded and have limited connectivity. The Catalina Member overlies the Hibernia A and B Pool reservoirs, but while drilling wells targeting the B Pool, the Catalina was usually avoided due to drilling difficulties in its carbonate-cemented intervals. In some cases the Catalina section was faulted out. For this reason, less data has been collected in the Catalina Member than drilling density might suggest.

As with the Hibernia A Pool and the Cape Island Member, development of the Catalina Member is expected to use re-completion of selected B Pool development wells as they near the end of their productive life. As some blocks are nearing abandonment in the Hibernia reservoir, up-hole occurrences of oil-bearing sands in the Catalina must now be addressed before wells are abandoned and reclaimed.

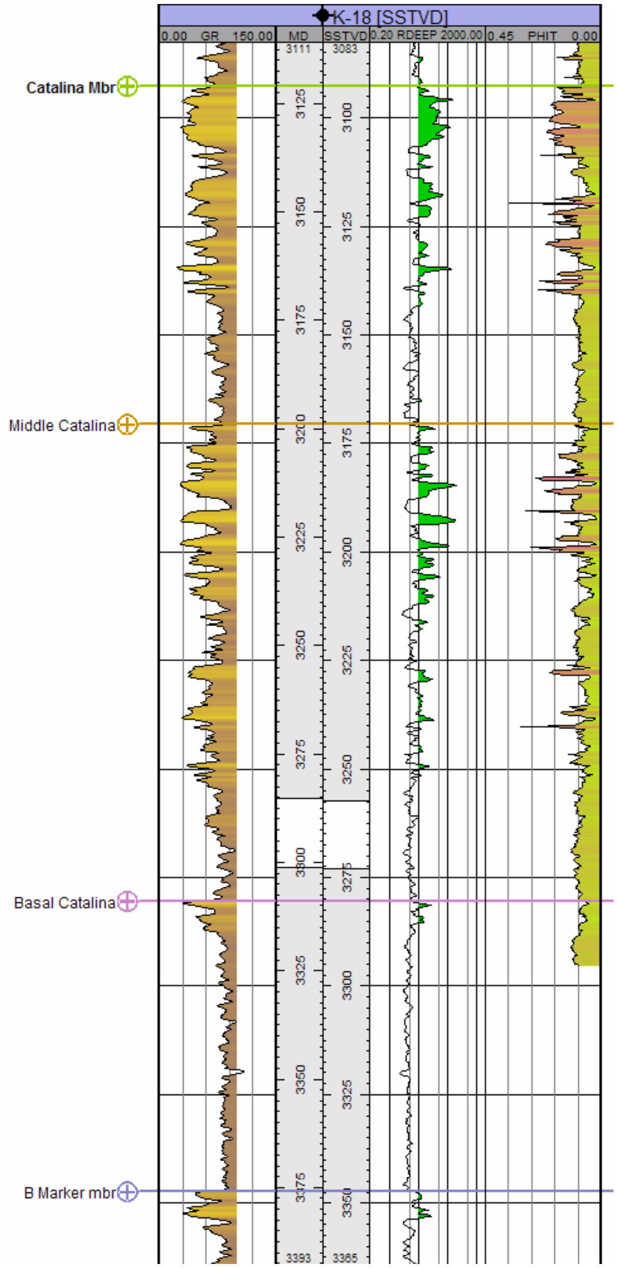
F.2 Geological/Geophysical Review

Board staff have reviewed the geological and geophysical data presented in the Application, and met with the Proponent's technical staff in a workshop in April 2010 to clarify geological information presented in the Application.

Because of the thin and discontinuous nature of Catalina sandstones, the limited log data available and the limits of seismic resolution, geological modeling is difficult in this interval, and therefore, the Petrel geological model for the Catalina Member is preliminary.

The Catalina Member is divided into three informal parasequences: basal, middle and upper. The proportion and quality of sandstone in each of these intervals generally increases upward (Figure F.1). The Catalina is interpreted to have been deposited in a marginal marine/delta environment. The gross thickness of the Catalina Member increases from 250 m in the north to 350 m in the southern part of the Hibernia Field. According to the Application, net sandstone thickness is typically no greater than 4-10 m, and the interval is most promising along the western margin of the field. Mapping by Board staff indicates that net pay in existing wells is somewhat thicker, from 5-21 m.

Figure F.1: Type Log for the Catalina Member, Showing Basal, Middle and Upper Parasequence Subdivisions. (Source: HMDC)



Board staff agree with the Proponent's assessment that reservoir quality is generally poor over some portions of the field. Preliminary analysis by Board staff suggests that areas of high quality reservoir do exist, though they may be interrupted by zones of extensive cementation, which act as barriers to flow. Results from formation flow tests have demonstrated flow rates up to approximately 2000 bbls/d in the case of the Hibernia K-18 well.

The Proponent has indicated that it is working on improving analysis of the Catalina reservoir, with a particular emphasis on structural re-interpretation and thin-bed formation evaluation, to ensure that the development potential is not underestimated. The Proponent has indicated that it will submit a summary of this work to the Board, and will provide an updated structural model for the full field when it becomes available.

F.3 Petrophysical Review

Many Hibernia B Pool wells intentionally penetrated poor or faulted out Catalina Member strata in order to avoid drilling challenges within the unit. This has resulted in sporadic data collection in this unit. Only a small number of wells have good quality log data over the complete Catalina interval. Core was obtained in the B-16 43 well and a full log suite acquired. Similarly B-16 28Z, B-16 39, and B-16 44 each penetrated a substantial Catalina section with full log suites acquired. Aside from these wells, only limited zones of good quality log data have been collected.

Windows of opportunity to collect core and good quality log data over the Catalina Member may open during future drilling of B Pool development wells. Board staff feels strategic data acquisition will enhance all parties understanding of the resource potential of the Catalina Member.

F.4 STOOIP and Reserves Estimates

A number of different and apparently unconnected fluid contacts characterize the Catalina Member, and this complicates estimation of hydrocarbon volumes. For the purpose of resource assessment, the Catalina Member has been divided into 6 mega-blocks, as indicated in the diagram below.

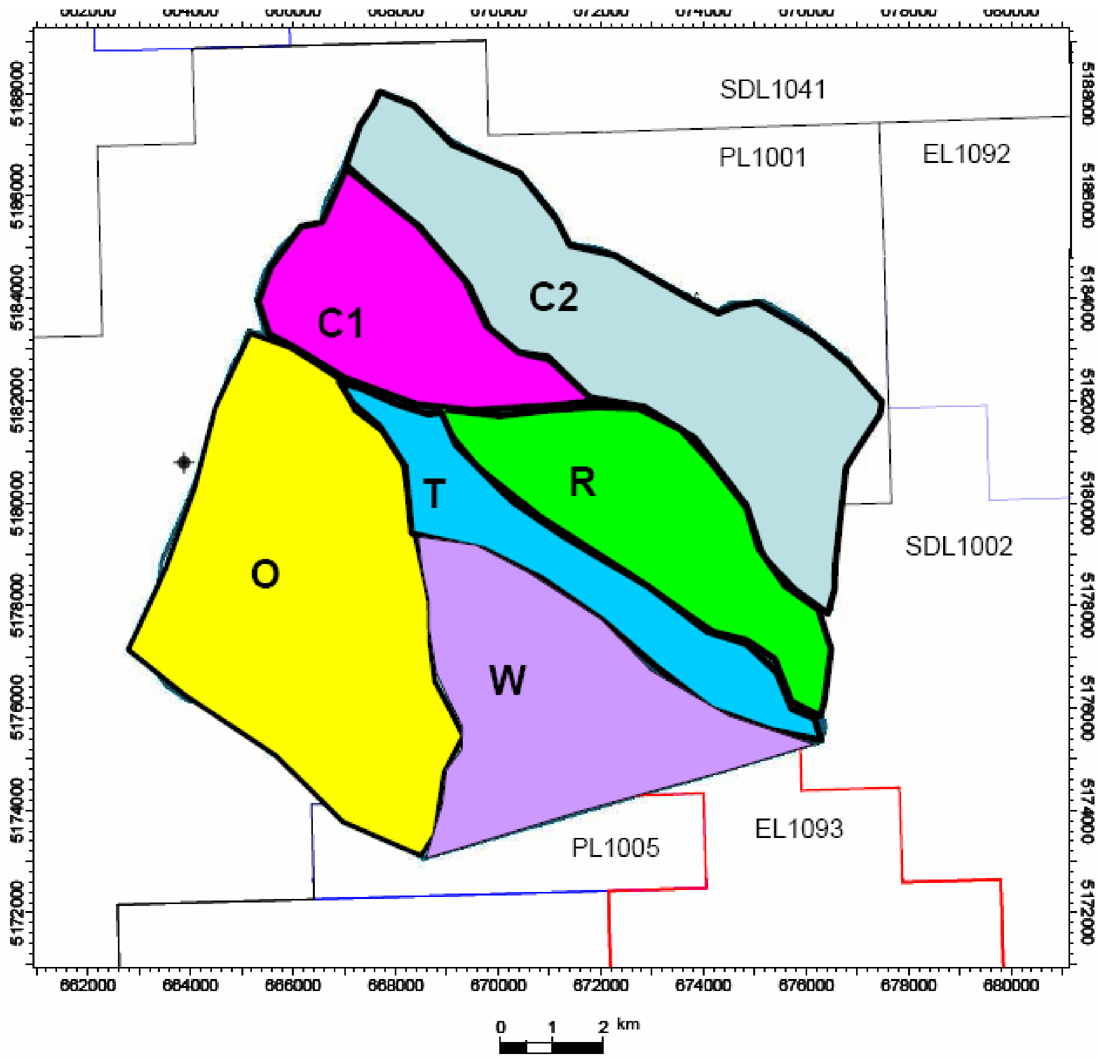


Figure F.2: Proponent's Catalina Member Mega-Blocks Used for Volumetric Estimate. (Source: HMDC)

Both the Board's and the Proponent's resource estimates for the Catalina assume that there will be no recovery in the most likely scenario, and all reserves estimates for the Catalina come in the upside scenario. The Proponent's upside scenario assumes a STOOIP of 102.5 MMbbls of oil and a recovery factor of 5% for an estimated 5.1 MMbbls of oil reserves. This estimate also includes an additional 1.8 MMbbls of condensate produced from the gas cap for a total reserve estimate of 6.9 MMbbls in an upside scenario.

Table F.1: Proponent's Catalina Member Upside Reserves Estimate. (Source: HMDC)

C-NLOPB Pool	Block	STOOIP (MB)	EUR Oil (MB)	EUR Cond (MB)	EUR Oil+Cond (MB)	Recovery (%)
Developed Blocks						
Catalina	C1	42.6	2.1	0.0	2.1	5%
Catalina	O	30.9	1.5	0.0	1.5	5%
Catalina	R	18.8	0.9	0.1	1.0	5%
Catalina	T	8.6	0.4	0.0	0.4	5%
Catalina	W	1.2	0.1	0.0	0.1	5%
Catalina	C2	0.4	0.0	1.7	1.7	--
Total Catalina		***102.5***	***5.1***	***1.8***	***6.9***	***7%***

The latest resource assessment conducted by the Board for the Hibernia Field was completed in 2006. Like the Proponent, Board staff concluded that there were no recoverable reserves from the Catalina Member in the most likely scenario. However, this assessment recognized a STOOIP of 138 MMbbls in the Catalina Member and assumed a recovery factor of 38% in an upside case, with oil reserves of 52 MMbbls.

Gas reserves from the Catalina Member, other than condensate production, are not included in the Catalina Member assessment, but gas production from the Hibernia Field is discussed as a concept under deferred development. Total gas in place in the Catalina is expected to be contained in both a gas cap and in solution, and is expected to be 153.1 GCF, as indicated in Table F.2.

Table F.2: Proponent's Catalina Member In-Place Volumes (Field Units). (Source: HMDC)

C-NLOPB Pool	Block	STOOIP (MB)	GIP Gas Cap (GCF)	GIP Solution (GCF)	GIP Total (GCF)
Developed Blocks					
Catalina	C1	42.6	0.0	28.7	28.7
Catalina	O	30.9	0.0	17.4	17.4
Catalina	R	18.8	4.0	12.7	16.7
Catalina	T	8.6	0.0	4.8	4.8
Catalina	W	1.2	0.0	0.8	0.8
Catalina	C2	0.4	84.5	0.2	84.7
Total Catalina		***102.5***	***88.5***	***64.6***	***153.1***

F.5 Development Strategy

The Proponent's proposed development strategy for the Catalina Member is the opportunistic completion of wells with Catalina sands that meet minimum thickness and reservoir quality criteria, either once the A Pool and B Pool have been isolated in those wells, or commingled with A and B Pool production as those wells near their end of life. Due to the thin-bedded nature and limited reservoir connectivity of the Catalina Member, it is unlikely that there will be opportunities for producer/injector pairs, so pressure depletion will be the most likely production mechanism.

In some cases, it is expected that Catalina reservoir will be present and oil bearing, but production will be uneconomical due to the liner top being below the Catalina interval. The Proponent only plans to re-complete wells where the potential additional recovery will offset the cost of the well operation.

After reviewing the Proponent's development strategy for the Catalina Member, Board staff accept that this is a reasonable strategy given the data available. Staff expect that development of the Catalina Member will be addressed in any application to abandon a well in the Hibernia Field as part of the well approval process. Should oil-bearing Catalina sands be present in the well, then the interval should be perforated, or the case made as to why it is uneconomical to do so.

The Proponent has stated in the Application that oil producers will be targeted to optimize future up-hole re-competitions as much as possible. In future wells to be drilled in the Hibernia Field, Board staff will consider the development of and data acquisition within the Catalina Member as part of the Approval to Drill a Well process.

F.6 Reservoir Simulation Model

As the Proponent states in the Application, no reservoir simulation models have been constructed for the Catalina Member.

F.7 Production Forecast

Because both the Proponent's and the Board's reserve estimates for the Catalina Member assume no production in the best estimate case and only include oil production in the upside scenario, there is no production forecast provided for the Catalina. Prior to any sustained production from the Catalina Member, the Proponent will be expected to submit a depletion plan containing oil, water and gas production profiles for the life of the field.

F.8 Development of the Catalina Member Within the Context of Hibernia Full Field

Development of the Catalina Member should provide a small uplift to Hibernia wells as they near the end of their productive life. There is uncertainty with respect to the productivity of the Catalina Member, as no wells have yet been completed in this interval. However, the resource is in place in the Hibernia Field and the exploitation of that resource needs to be addressed before any Hibernia wells that intersect the Catalina Member are abandoned.

Board staff expect that updates to the understanding of the Catalina Member will be presented in the Annual Resource Management Plan. This is to include any new seismic interpretation, geological data, petrophysical analysis, reservoir simulation updates, reserve updates or production data.

F.9 Conclusions and Recommendations

- Based on a review of geological, geophysical, petrophysical and reservoir engineering data, Board staff consider the information available for the Catalina Member to be insufficient and recognize that additional study and work is required.
- The Proponent's best estimates of STOOIP volumes [102.5 MMbbls (16.3 MMm^3) of oil and 153.1 GCF (4.3 Gm^3) of gas] are considered possible.
- The Proponent's recovery factor (5%) is significantly different from the Board's upside estimate, but is reasonable if injection support is not feasible.
- Perforation of the Catalina will be addressed on a well-by-well basis in the Approval to Alter the Condition of a Well or Approval to Drill a Well process.
- Any commingling of production of the Hibernia A Pool or B Pool with the Catalina will require a separate approval.
- Updates to the progress of development of or data acquisition in the Catalina Member will be presented in the Annual Resource Management Plan Update.

Board staff recommend that the Proponent's proposed approach for the development of the Catalina Member be approved and that production from this member should be addressed on a well by well basis. The progress of the development of this resource will be reviewed and updated in the Proponent's Annual Resource Management Plan.

Appendix G

Cape Island Member

G.1 Cape Island Member

The Cape Island Member consists of a series of thin sandstones interbedded with shale, that forms the uppermost part of the Hibernia Formation. Thin, porous oil- and gas-bearing Cape Island sandstones have been encountered in some wells in the Hibernia Field targeting the Hibernia B Pool; however, reservoir sandstones within the Cape Island are not laterally extensive over the entire Hibernia Field.

As with the A Pool and Catalina Member, development of the Cape Island Member is expected to use re-completion of selected B Pool development wells as they near the end of their productive life. As some blocks are nearing the end of their productive life in the B Pool, the Cape Island must now be addressed before wells are abandoned and reclaimed.

G.2 Geological/Geophysical Review

Board staff have reviewed the geological and geophysical data presented in the Application, and met with the Proponent's technical staff in a workshop in April 2010 to clarify geological information about the Cape Island Member.

Because of the thin and discontinuous nature of Cape Island sandstones, the scarcity of log data and the limits of seismic resolution, geological modeling is difficult in this interval, and therefore, no geological model was submitted for this interval.

At the Hibernia Field, the Cape Island Member consists of a series of marginal marine cycles, wherein thin sandstones are interbedded with thick silty shale intervals. Individual sandstones vary in their lateral distribution with only one, known informally as the "M-54 sand", present across most of the field (Figure G.1). Thicknesses and reservoir quality of each sandstone unit also tend to vary across the field. Board staff agree with the Proponent's assertion that the heterogeneous and discontinuous nature of the Cape Island Member is likely to result in several small, unconnected hydrocarbon accumulations.

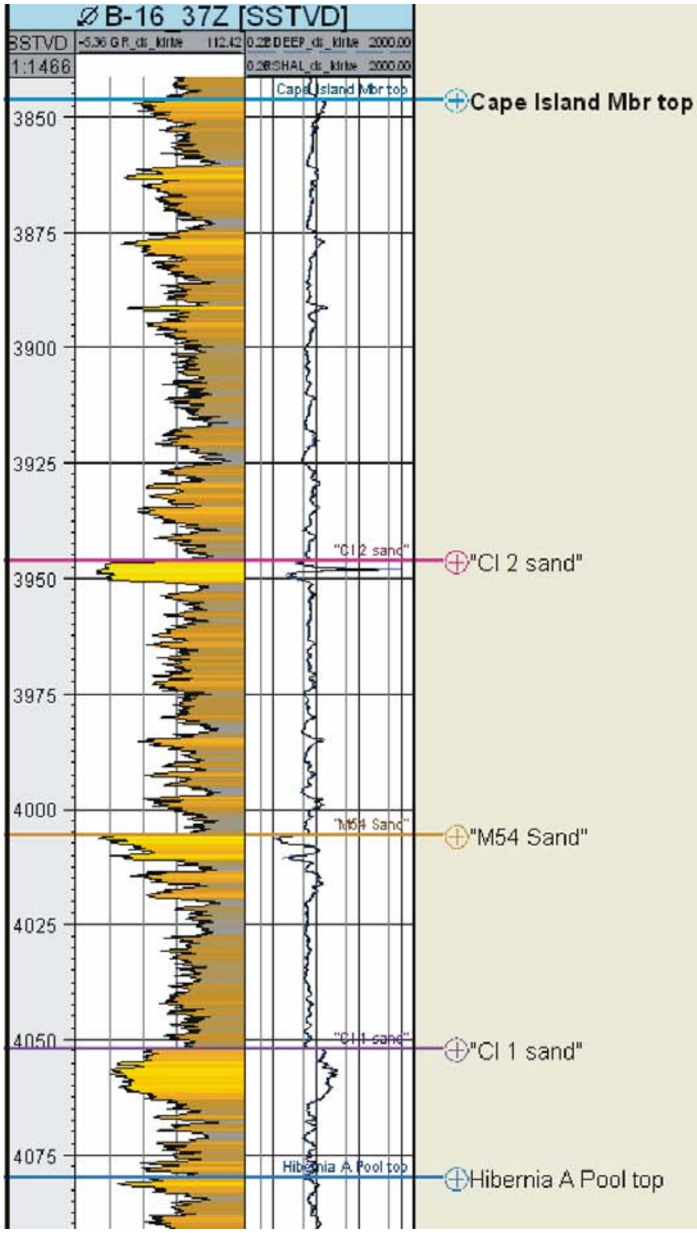


Figure G.1: "Type" log for the Cape Island Member, Showing Thin Sand Intervals. (Source: C-NLOPB)

Preliminary mapping by Board staff suggests that individual sandstones within the Cape Island Member occur in elongate trends, roughly oriented southwest-northeast. The Proponent has indicated that it is working on improving analysis of the Cape Island reservoir, with a particular emphasis on mapping, structural re-interpretation and thin-bed formation evaluation, to fully evaluate the potential of this minor reservoir. It is expected that the Proponent will submit a summary of this work to the Board, and will provide an updated structural model for the full field when it becomes available.

G.3 Petrophysical Review

The Proponent provided a summary of the Cape Island Member in addition to the methodology used in assessing this unit. All wells encountering porous sands in the Cape Island Member have a resistivity profile that suggest they are hydrocarbon bearing. Eight wells have a net pay greater than three metres using a 10% porosity cutoff. This cutoff may be optimistic as there are no cores in the Cape Island Member and a porosity/permeability relationship cannot be established.

Windows of opportunity to collect core and good quality log data over the Cape Island Member may open during future drilling of B Pool development wells. Board staff feels strategic data acquisition will enhance all parties understanding of the resource potential of the Cape Island Member.

G.4 STOOIP and Reserves Estimates

As the Cape Island Member is expected to have limited lateral extent in the Hibernia Field, the resource assessment for the reservoir is limited to only those wells that have encountered porous, oil-bearing sandstone in the Cape Island Member.

The Proponent’s STOOIP estimate for the Cape Island Member is 7.4 MMbbls. Reserves estimates assume a recovery factor of 5% for 0.37 MMbbls of recoverable oil in an upside scenario with an additional 0.006 MMbbls of condensate being produced. The most likely recoverable estimates for the Hibernia Field assume no recovery in the Cape Island Member. The Proponent’s Cape Island reserves estimate is presented in Table G.1.

Table G.1: Proponent's Cape Island Member Upside Reserves Estimate. (Source: HMDC)

Pool	Well	EUR Oil (Mm^3)	EUR Cond (Mm^3)	EUR Oil+Cond (Mm^3)	Recovery (%)
Developed Blocks					
Cape Island	B-16_10Z	0.012	0.000	0.012	5%
Cape Island	B-16_7	0.012	0.000	0.012	5%
Cape Island	B-16_4Z	0.003	0.000	0.003	5%
Cape Island	B-16_13	0.004	0.000	0.004	5%
Cape Island	B-16_35	0.004	0.000	0.004	5%
Cape Island	B-16_14	0.006	0.000	0.006	5%
Cape Island	B-16_9	0.001	0.000	0.001	5%
Cape Island	B-16_8	0.006	0.000	0.006	5%
Cape Island	B-16_50	0.002	0.000	0.002	5%
Cape Island	B-16_31	0.001	0.000	0.001	5%
Cape Island	B-16_26	0.001	0.000	0.001	5%
Cape Island	B-16_45	0.001	0.000	0.001	5%
Cape Island	B-16_49Z	0.001	0.000	0.001	5%
Cape Island	B-16_21	0.001	0.000	0.001	5%
Cape Island	B-27	0.000	0.000	0.000	5%
Cape Island	B-16_53	0.000	0.000	0.000	5%
Cape Island	B-16_16	0.002	0.000	0.002	5%
Cape Island	B-16_12	0.001	0.000	0.001	5%
Cape Island	B-16_40	0.000	0.000	0.000	5%
Cape Island	B-16_36	0.000	0.000	0.000	5%
Cape Island	B-16_44	0.000	0.000	0.000	5%
Cape Island	B-16_47	0.000	0.000	0.000	5%
Cape Island	B-16_33	0.000	0.000	0.000	5%
Cape Island	B-16_24	0.000	0.000	0.000	5%
Cape Island	B-08	0.000	0.001	0.001	0%
Cape Island	B-16_29	0.000	0.000	0.000	5%
Cape Island	B-16_15Z	0.000	0.000	0.000	5%
Total Cape Island		***0.058***	***0.001***	***0.059***	***5%***

The latest resource assessment conducted by the Board for the Hibernia Field was completed in 2006. The Cape Island Member was not included in this assessment due to a lack of data. Therefore the Board has no STOOIP or reserves listed.

Gas resources from the Cape Island Member, other than condensate production, are not included in the Cape Island Member assessment, but gas production from the Hibernia Field is discussed as a concept later under deferred development. Total gas in place in the Cape Island Member is expected to be contained in both gas cap and in solution, and is expected to be 5.0 GCF, as indicated in Table G.2.

Table G.2: Proponent's Catalina Member In-Place Volumes (Field Units). (Source: HMDC)

Pool	Well	STOOIP (MB)	GIP Gas Cap (GCF)	GIP Solution (GCF)	GIP Total (GCF)
Developed Blocks					
Cape Island	B-16_10Z	1.486	0.000	0.936	0.936
Cape Island	B-16_7	1.448	0.000	0.913	0.913
Cape Island	B-16_4Z	0.387	0.000	0.244	0.244
Cape Island	B-16_13	0.524	0.000	0.330	0.330
Cape Island	B-16_35	0.491	0.000	0.309	0.309
Cape Island	B-16_14	0.692	0.000	0.436	0.436
Cape Island	B-16_9	0.124	0.000	0.078	0.078
Cape Island	B-16_8	0.781	0.000	0.492	0.492
Cape Island	B-16_50	0.258	0.000	0.163	0.163
Cape Island	B-16_31	0.083	0.000	0.052	0.052
Cape Island	B-16_26	0.128	0.000	0.080	0.080
Cape Island	B-16_45	0.116	0.000	0.073	0.073
Cape Island	B-16_49Z	0.073	0.000	0.046	0.046
Cape Island	B-16_21	0.143	0.000	0.090	0.090
Cape Island	B-27	0.029	0.000	0.018	0.018
Cape Island	B-16_53	0.056	0.000	0.035	0.035
Cape Island	B-16_16	0.267	0.000	0.168	0.168
Cape Island	B-16_12	0.065	0.000	0.041	0.041
Cape Island	B-16_40	0.042	0.000	0.026	0.026
Cape Island	B-16_36	0.050	0.000	0.032	0.032
Cape Island	B-16_44	0.020	0.000	0.013	0.013
Cape Island	B-16_47	0.059	0.000	0.037	0.037
Cape Island	B-16_33	0.028	0.000	0.018	0.018
Cape Island	B-16_24	0.031	0.000	0.020	0.020
Cape Island	B-08	0.000	0.300	0.000	0.300
Cape Island	B-16_29	0.030	0.000	0.019	0.019
Cape Island	B-16_15Z	0.020	0.000	0.012	0.012
Total Cape Island		***7.431***	***0.300***	***4.681***	***4.981***

G.5 Development Strategy

As is the case with the Catalina, the Proponent’s proposed development strategy for the Cape Island Member is the opportunistic completion of wells with Cape Island sands that meet minimum criteria for thickness and reservoir quality, either once the A Pool and B Pool have been isolated in those wells, or commingled with A and B Pool production as those wells near their end of life. Due to the thin-bedded nature, limited reservoir connectivity and unknown lateral extent of the Cape Island Member, it is unlikely that there will be opportunities for producer/injector pairs, so pressure depletion will be the most likely production mechanism.

In some cases, it is expected that the Cape Island Member will be present and oil-bearing, but recompletion will be uneconomical. The Proponent only plans to re-complete wells where the potential additional recovery will offset the cost of the well operation.

After reviewing the Proponent's development strategy for the Cape Island Member, Board staff accept that this is a reasonable strategy given the data available for the Cape Island Member. The Board expects that development of the Cape Island Member will be addressed in any application to abandon a well in the Hibernia Field. Should oil-bearing Cape Island sands be present in the well, then the interval should be perforated, or the case made as to why it is uneconomical to do so.

The Proponent has stated in the Application that oil producers will be targeted to optimize future up-hole re-competitions as much as possible. In future wells to be drilled in the Hibernia Field, Board staff will consider the development of and data acquisition within the Cape Island Member as part of the Approval to Drill a Well process.

Board staff will continue to review its assessment of the Cape Island Member as more data is acquired.

G.6 Reservoir Simulation Model

As the Proponent states in the Application, no reservoir simulation models have been constructed for the Cape Island Member.

G.7 Production Forecast

Both the Proponent's and the Board's reserves estimates for the Cape Island Member assume no production in the best case scenario, therefore, there is no production forecast for the Cape Island. Prior to any sustained production from the Cape Island Member, the Proponent will be expected to submit a depletion plan containing oil, water and gas production profiles for the life of the field.

G.8 Development of the Cape Island Within the Context of Hibernia Full Field

Development of the Cape Island Member has potential to provide an incremental uplift to Hibernia wells as they near the end of their productive life. There is uncertainty with respect to the productivity of the Cape Island Member as no wells have yet been completed in this interval. However, the resource is in place in the Hibernia Field and the exploitation of that resource needs to be addressed before Hibernia wells that intersect the Cape Island Member are abandoned.

Board staff expect that updates to the understanding of the Cape Island Member will be presented in the Annual Resource Management Plan. This is to include any new seismic interpretation, geological data, petrophysical analysis, reservoir simulation updates, reserve updates or production data.

G.9 Conclusions and Recommendations

- Based on a review of geological, geophysical, petrophysical and reservoir engineering data, Board staff consider the information available for the Cape Island Member to be insufficient and recognize that additional study and work is required.

- The Proponent's best estimates of STOOIP volumes [7.4 MMbbls (1.2 MMm^3) of oil and 5.0 GCF (0.1 Gm^3) of gas] are considered possible.

- Perforation of the Cape Island Member will be addressed on a well-by-well basis in the Approval to Alter the Condition of a Well or Approval to Drill a Well process.

- Any commingling of production of the Hibernia A Pool or B Pool with the Cape Island will require a separate approval.

- Updates to the progress of development of or data acquisition in the Cape Island Member will be present in the Annual Resource Management Plan Update.

Board staff recommend that the Proponent's proposed approach for the development of the Cape Island Member be approved and that production from this member should be addressed on a well by well basis. The progress of the development of this resource will be reviewed and updated in the Proponent's Annual Resource Management Plan.

Appendix H

Status of Hibernia Conditions

Decision 2006.01

Condition 2006.01.01

The Proponent submit, within 9 months of drilling of the delineation well in the NW wedge, a report describing the learnings from that well in the context of the overall Ben Nevis-Avalon development.

Status: Satisfied

The Board informed HMDC in April 2008 that the report was reviewed and the condition had been satisfied.

Condition 2006.01.02

The Proponent submit, in its Annual Production Report submitted to the Chief Conservation Officer, details of activities undertaken to increase oil recovery from the Ben Nevis-Avalon Reservoir.

Status: Ongoing

Decision 2003.01

Condition 2003.01.01

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.

Status: Ongoing

Condition 2003.01.02

(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.

Status: Satisfied

HMDC presented a PWRI assessment to the Board in June 2008 in which HMDC recommended not implementing PWRI at Hibernia based on technical, operations, environment and economic considerations. Board accepted this assessment and notified that the condition was satisfied.

Condition 2003.01.03

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).

Status: Ongoing

Decision 2003.02

The Proponent submit, by June 30, 2004, the following:

(a) A report detailing the results of relevant analyses of the northwest area of the Ben Nevis/Avalon reservoir including analysis of the seismic data to assess the Murre Fault seal and direct hydrocarbon indicators at the northwest wedge location; and, recovery from the Ben Nevis-Avalon Reservoir.

(b) A plan acceptable to the Board for delineation of the northwest area of the Ben Nevis/Avalon reservoir.

Status:

Condition 2003.02.01(a) and (b): Satisfied

The Board informed HMDC in May 15, 2008 that based on the information provided in letters of February 28, 2005 and November 2006 the condition had been satisfied

Decision 2000.01

Condition 2000.01.1

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: Ongoing

Decision 97.01

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 therefore 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): Satisfied

In February 2009, the Board approved the HMDC A Pool Depletion plan submitted in June 2008 and was notified that the condition was satisfied

Condition 97.01.1(ii): Satisfied

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 is the subject of this Decision 2006.01.

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.

(ii) 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 97.01.5

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: Satisfied

In December, 2002 the Proponent submitted an application for extension of the Avalon appraisal period to December 31,2005. This request is the subject of this Decision 2006.01. As noted above, the Board informed HMDC in April 2008 that the report was reviewed and the condition had been satisfied.

Decision 90.01

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

Decision 86.01 (Benefits Plan)

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: 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: Ongoing

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

Decision 86.01 (Development Plan)

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

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): Ongoing

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): 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): Ongoing

> 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 3(iii): Ongoing

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): Ongoing

Condition #9

It is a condition of the approval of the Hibernia Development Plan 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: Satisfied

Appendix I

Public Comments

CNLOPB

The proposal to proceed with using the Hibernia Platform is a great and forward thinking use of existing facilities.

The existing field will and has decreased in production and connecting the remote Hibernia south field certainly will prolong the use of these costly facilities.

Couple things to bear in mind:

· Converting the platform to accept the new production will require a very complex and detailed integration into the various safety systems and production lines.

· There are many systems and piping on Hibernia which will require careful inspection and prolonged production outages to allow safe tie-ins. Remember Hibernia is aging every day and with age comes surprises.

· Avoid any single train or non-spared production systems. In many cases, stopping production creates more panic or issues then a 50% reduction in production.

· I'm certain the Lesson Learned in the Gulf will be applied to the subsea systems and their designs. Continue to ask and purse " IF" there was an incident on Hibernia or from the South field can the system be controlled or stopped remotely. Getting the personnel to safety is key, but the Rig also needs to have safe guards to both monitor and stop production independently.

· I'm not certain related to the present control systems but I know Hibernia has the ability to monitor process parameters remotely, but is there provisions to Operate Remotely from a safe environment without the normal panic during any offshore incident – This remote control should be done on a 24/hrs bases and not just during the office hours. Trans Canada and many other operator operate remotely and gain the global view, with local plants STILL making final normal decisions. This is also a great way to train new panel operators without increasing persons offshore. This could even be done with handy capped personnel.

The only downside I can see is with a New Southern fields available, the older fields will take a backseat. The focus will be on obtaining Max production, Safeguards need to be in place to insure all fields are produced to the last drop, even thought the water production and costs will be greater.

Douglas V. Knutson

X-Hibernia Startup Secondee
Tengiz Sour Gas Plant
Machinery Supervisor
Rm 222 / Ph 7680
Atyrau Oblast, Zhilyoy Region
060011 Republic of Kazakstan

NOIA

NOIA Response to
Amendment to the Hibernia Benefits Plan: Hibernia Southern Extension Project
May 2010

SUBMISSION

NOIA's Interest

The Newfoundland & Labrador Oil & Gas Industries Association (NOIA) is Canada's largest offshore oil & gas industries association. It has been headquartered in Newfoundland and Labrador since its founding in 1977. With over 500 members in Newfoundland & Labrador and around the world, NOIA represents the supply & service sector of the province's oil and gas industry.

NOIA members provide products and services for the petroleum sector; associate members include petroleum companies, trade associations, educational institutions, and government bodies and agencies.

NOIA's mission is "to promote development of East Coast Canada's hydrocarbon resources and to facilitate its membership's participation in global oil & gas industries".

NOIA believes that hydrocarbons are a valuable natural resource, and that the exploitation of a valuable resource must have a substantial and positive economic impact that can be captured by the industry and the economy of Newfoundland & Labrador.

GENERAL COMMENTS

The Amendment to the Hibernia Benefits Plan: Hibernia Southern Extension Project (HSE Project) provides adequate information regarding the development of up to 5 additional fault blocks in the southern sector of the Hibernia Field. Generally speaking, the amendment responds to questions regarding the Proponent's (Hibernia Management and Development Company Ltd.) commitment to the open and timely communications that foster full and fair opportunity for the resident supply and service sector to participate in the development.

It is, as always, NOIA's position to advocate for full and fair opportunity for the local supply and service sector. To that end, **we strongly believe that the amount of local content should be at least as much as that accomplished on previous projects**. Along with that, a step-change should be made from earlier projects which recognizes the growth and development in local capabilities of the supply and service sector in our province. Simply put, each new project in our offshore should 'raise the bar' from previous developments.

It is NOIA's viewpoint that the North Amethyst Project is comparable to HSE, therefore we believe that it should be held up as a benchmark to measure and ensure a step-change in benefits is made to ensure a noted increase in work scope is completed locally.

NOIA's objective in this review process is to support responsible development of the Hibernia Southern Extension resource, to recognize the proponents' efforts thus far to ensure that the objectives of all stakeholders are achieved in the development of this resource and to encourage continuous improvement of those efforts, especially in the area of Canada – Newfoundland and Labrador Benefits.

Specifically, NOIA encourages Hibernia Management and Development Company Ltd. (HMDC) to identify clear and transparent benefit targets for the HSE Project and to establish mechanisms for measuring benefit (both as proposed in bid documents and as performed in execution of work) and tracking achievement. NOIA expects the data associated with the tracking of achievement be made available on a quarterly basis with total deliverables reported at the completion of the project.

Furthermore, we stipulate that production operation benefit numbers also be monitored and reported accordingly.

Although the obligations arising from the Accord Acts extend to the contractor, without specificity in the DPA, international EPC contractors do not have the same incentive to support local companies as do the project proponent.

NOIA recommends specificity at the DPA stage to identify clearly the activity to be undertaken in NL.

NOIA encourages responsible management of Canada-Newfoundland & Labrador Benefits. To this end, **NOIA recommends that Canada-Newfoundland & Labrador's regulatory practices and processes be refined to be more specific, thereby increasing accountability and demonstrating a firm commitment to the local supply and service sector.** NOIA suggests the following revisions:

- Projects should be benchmarked as follows: at least as much work should be done locally as has been completed on past projects.

- A step change should also be implemented to recognize growth of industry capability. This step change could be the involvement of local engineering companies in the development of the subsea control systems.

- All "offshore activity" must be monitored and regulated (including ensuring appropriate benefits) as provided for in the *Atlantic Accord.*

- All development plans must contain an outline of specific and measurable supplier development strategies for the project. Further, these supplier development strategies must contain a list of action items supporting this.

- Decision reports must delineate specific timeframes for required action and reporting and specific percentage targets for local contract award.

- The regulator must develop tracking mechanisms to measure, record and assess a proponent's compliance to Development Plans and Decision Reports.

- The regulator must develop progressive instruments to encourage compliance and work towards a cooperative approach to attaining regulatory efficiency.

- The regulator must ensure that adequate tracking mechanisms to measure, record and assess a proponent's compliance to local benefits during production operation project phase are in place.

SPECIFIC COMMENTS

Responsible Resource Development

Hydrocarbons are a non-renewable resource and as such if exploitation of the resources offshore Newfoundland & Labrador is to provide lasting benefit to the economy of the province and the country, an exploitation strategy must be devised that encourages development of a *sustainable* resident petroleum industry.

NOIA is satisfied, thus far, that HMDC has taken this approach in its strategy for the development of the HSE Project. Opportunity will be provided for local participation, technology transfer and supplier development. New commitments in the area of Research & Development as well as Gender Equity and Diversity will also help the resident industry to evolve.

NOIA encourages HMDC to work closely with all stakeholders to enhance local participation to a level that exceeds the DPA targets.

Project Execution

All HSE Project activities will be managed from the Proponents' offices in St. John's, NL. In doing so, HMDC has promoted equality of access for the resident supply and service sector to the project team at the earliest possible stage.

Additionally, Front-End Engineering & Design (FEED) was executed "in house" supported by various specialist engineering contractors with technical support from ExxonMobil headquarters in Houston.

The term "In House" does not differentiate from work completed in NL and work completed internationally by the proponent. The involvement of local companies at the FEED stage is critical to obtaining technology transfer and elevating local capability for future projects.

While FEED is complete, NOIA would like to express its concern about local content at this stage. More detailed information should have been provided on local content and supplier development at the FEED stage. This detailed information should specify the activity to be performed in NL.

The execution strategies for each major component of the project are as follows:

- Detailed Engineering will be undertaken by international specialist subsea Contractors
- Construction and Installation will be undertaken by international specialist subsea contractors

- Topsides Modifications will be undertaken by HMDC's long-term EPC modifications contractor

- Platform drilling will consist of up to a 5-well program undertaken by HMDC using existing drilling organization, support infrastructure and contractors

- Subsea drilling will consist of up to a 5-well program undertaken by HMDC using a subsea drilling contractor commencing in 2012

- Production operations will be undertaken by HMDC using existing offshore production facilities and support infrastructure

- Logistics and support will be undertaken by HMDC using existing shore-based infrastructure including support vessels, helicopter support, shore-base, and producing operations organization.

HMDC will require Engineering, Procurement and Construction (EPC) contractors to have contracts and procurement offices in the Province. The proponent acknowledges the local capability to supply fabricated components and to assist in system integration testing. It is clear that capability exists locally to fabricate the pipeline end terminations, drilling template/manifolds and subsea manifolds as well as to conduct system integration testing. These should be specified **TO BE** completed in NL.

NOIA recommends that the Proponents provide detailed information with respect to the detailed engineering and construction and installation that will be required to undertake the Project, specifically with respect to local content.

Benefits Monitoring and Tracking

HMDC has made efforts to foster opportunities for the resident supply and service sector. However, targets and measurement mechanisms are needed to validate achievement of objectives and to track areas that need additional effort. HMDC have indicated that the intention is to utilize HMDC's established internal processes to monitor and report benefits related information for the Project.

Key elements of the process are:

- Employment reporting (number of people directly employed on the project) reported quarterly as per HMDC's quarterly benefits report

- Expenditure/content reported quarterly as per HMDC's quarterly benefits report

- Procurement and contracting activities reported as per the C-NLOPB's established Guidelines

- R&D expenditures reported in accordance with the Board's established Guidelines

- Gender Equity and Diversity reporting per processes and procedures to be established in consultation with various stakeholder groups, including the C-NLOPB.

The Benefits Plan Amendment outlines some specific targets and action items for R&D as well as Gender Equity and Diversity. However, there is no indication of the specific value HMDC places on any of the above elements, nor is there any hierarchy of priority.

NOIA recommends that for all bid packages, all criteria should be identifiably weighted, including all key elements above which demonstrate the Canada - Newfoundland and Labrador economic impact.

Contracting Strategy and Local Capability Assessment

Acknowledging that international competitiveness is a challenge, **NOIA recommends that HMDC explore the potential for a technology transfer/supplier development arrangement that would enable a local company to develop capacity for the engineering, procurement and construction (EPC) contract packages.**

RECOMMENDATION

NOIA supports the HSE project, particularly in view of the proponent's increased commitment to working with the local stakeholders to enhance resident supply and service capability.

The project as proposed will provide:

- ***new drilling activity***, which represents substantial local contracting and employment opportunity and demonstrates confidence in the region and helps attract new investment;

- ***new opportunity*** for the resident petroleum supply and service sector;

- ***business certainty*** for key HSE contractors whose contracts will be extended as per the Plan Amendment (and for their supply chain) at a time of uncertainty in the industry;

- ***maximization of existing offshore facilities***, which improves overall project cost-effectiveness and thus enhances our region's competitive positioning for investment attraction;

In summary, NOIA recommends that:

1. NOIA recommends specificity at the DPA stage to identify clearly the activity to be undertaken in NL.

2. NOIA recommends that Canada-Newfoundland & Labrador's regulatory practices and processes be refined to be more specific, thereby increasing accountability and demonstrating a firm commitment to the local supply and service sector.
    a. In particular, projects should be benchmarked as follows: at least as much work should be done locally as has been completed on past projects.
    b. A step change should also be implemented to recognize growth of industry capability. This step change could be the involvement of local engineering companies in the development of the subsea control systems.

3. Proponents provide detailed information with respect to the detailed engineering and construction and installation work to be done to progress the project.

4. In all bid packages, all criteria should be identifiably weighted, including Canada - Newfoundland and Labrador economic impact.

5. HMDC explore the potential for a technology transfer/supplier development arrangement that would advance local capacity to bid on EPC contracts.

Comments on Hibernia Southern Extension Project

Hibernia Development Plan Amendment
and
Amendment to the Hibernia Benefits Plan

Women in Resource Development Corporation
53 Bond Street, Suite 300
St. John's, NL
A1C 1S9

Tel: 709-738-3713/1-800-738-3713
Fax: 709-738-3743

www.wrdc.nf.ca

WRDC Comments on Hibernia Southern Extension Project

Women in Resource Development Corporation (WRDC) is pleased that the Hibernia Development Plan Amendment and the Amendment to Hibernia Benefits Plan have been submitted for the Hibernia Southern Extension Project. This project represents long-term social and economic benefits for the people of Newfoundland and Labrador through the preservation of employment levels and a greater royalty return for the province than any previous project.

We note the provisions for gender equity in the Amendment to Hibernia Benefits Plan. WRDC looks forward to working in collaboration with the project proponents to ensure that women have equal access to the employment opportunities and benefits generated from this exciting project. This will involve not only ensuring that there are inclusive policies and programs in place, but also that there are strong implementation strategies to accompany the women's employment plan and business access strategy. We feel that such strategies are essential, since despite the development and corporate support of gender equity plans, statistics show that progress on gender equity is slow. This is particularly evident in the skilled trades and technology areas in currently operating offshore projects. Despite efforts, a significant gender gap continues to exist.

WRDC believes that in order to be properly and fully implemented, gender equity and women's employment initiatives require focused regulation and collaboration among all key stakeholders – including industry, government, labour, regulatory bodies, educational institutions, and community organizations. We will be pleased to work with all stakeholders to make this important outcome a reality.