Staff Analysis

of the

Hebron Development Plan

Amendment Application 2022

Jeanne d'Arc Formation Sand Intervals

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List of Abbreviations

3D	three-dimensional
Accord Act	*Canada-Newfoundland and Labrador Atlantic Accord Implementation Act* (references to federal version)
APSDM	anisotropic post-stack depth migration
bbl	barrel
bbl/d	barrels per day
°C	degrees Celsius
CEAA	Canadian Environmental Assessment Agency
C-NLOPB	Canada-Newfoundland and Labrador Offshore Petroleum Board
CCO	Chief Conservation Officer
CRI	cuttings reinjection
CSR	Comprehensive Study Report
DPA	Development Plan Amendment
DST	drill stem test
EA	Environmental Assessment
EOD	environment of deposition
EUR	estimated ultimate recovery
FFAW	Fish, Food & Allied Workers - Unifor
FWL	free water level
GCF	billion cubic feet
g cm-3 (g/cc)	grams per cubic centimeter
GHG	greenhouse gas
Gm^3	billion cubic metres
g mol-1	grams per mol
GOR	gas-oil ratio
ICV	inflow control valve
IWC	intelligent well completion
JDA	Jeanne d'Arc (Formation)
kbd	thousands of barrels per day
km	kilometre
km3/d	cubic kilometres per day
kPa	kilopascals
kpa/m	kilopascals per meter
kT CO2e/year	kilotonnes carbon dioxide equivalent per year
LDAR	Leak detection and repair
LWD	logging while drilling
m^3	cubic metres
m^3/d	cubic metres per day
m^3/d/kPa	cubic metres per day per kilopascal

MBAL	material balance analysis
MDT	Modular Formation Dynamic Tester
mg/l	milligrams per litre
Mm^3/d	million cubic metres per day
MMbbl	million barrels
MMm^3	million cubic metres
mPa	megaPascal
MMscf/d	million standard cubic feet per day
mTVDss	metres true vertical depth subsea
NTG	net-to-gross
PI	productivity index
PL	Production Licence
PTA	pressure transient analysis
ODT	oil-down-to
OOIP	original oil in place
OWC	oil-water contact
Proponent	ExxonMobil Canada Properties
SCAL	special core analysis
SDL	Significant Discovery Licence
sm^3	standard cubic metres
Sm^3/d/bar	standard cubic metres per day per bar
STB/d/bar	Stock-tank barrels per day per bar
STOOIP	stock-tank original oil in place
TTI	tilted transverse isotropy
V	volume
VEC	air quality valued ecosystem component
VpVs	compressional-to-shear velocity ratio
WL	wireline

1. Executive Summary

On November 18, 2022, ExxonMobil Canada Properties (Proponent) submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) on behalf of its coventurers Chevron Canada Limited, Suncor Energy Inc., Equinor Canada Limited and Nalcor Energy - Oil and Gas Inc. a Development Plan Amendment Application related to development of the remaining sand reservoirs within the Hebron Jeanne d'Arc (JDA) Formation. A completeness review was issued to the Proponent on January 17, 2023, and subsequent documents were received on January 24 and February 3, 2023.

The proposed development is an amendment to the existing Hebron Development Plan (Decision Report 2012.01).

The documents describe the Proponent's intention to develop the remaining sand reservoirs in the JDA Formation using the same general approach to Hebron Project development, including existing facilities and drill well slots, recovery methods and systems. The addition of these JDA Formation sands is not expected to change the costs nor the environmental factors associated with the existing Hebron facility. In a success case, this development would constitute up to approximately 5% of the expected ultimate recovery (EUR) at Hebron. Development of this resource will assist in offsetting the natural decline in production at Hebron as the next step to optimizing Hebron resources, consistent with good oil field practice.

Upon receipt of the Development Plan Amendment Application, staff reviewed the documents for completeness. Staff requested additional information on January 17, 2023. In response, the Proponent submitted the following items on January 24, 2023 and February 3, 2023. These documents are considered "the Application" and are the subject of this Staff Analysis:

- Hebron Development Plan Amendment 2022 Jeanne d'Arc Formation Sand Intervals - Revision;
- Hebron Development Plan Amendment 2022 - Jeanne d'Arc Formation Sand Intervals - Change Registry;
- Hebron L-93 29 - Reservoir Fluids Report - Modular Formation Dynamics Tester Samples - F Sand;
- Hebron L-93 29 - Reservoir Fluids Report - Pressure Volume Temperature Study - Modular Formation Dynamics Tester Samples - C Sand;
- Hebron L-93 29 - Reservoir Fluids Report - Pressure Volume Temperature Study - Modular Formation Dynamics Tester Samples - B Sand;
- Hebron L-93 29 - Reservoir Fluids Report - Water Analysis;
- Hebron L-93 30Z - Reservoir Fluid Report - Produced Water.

Information provided by the Proponent in response to the letter was assessed by staff and on February 23, 2023, the Application was deemed complete.

On July 19, 2023, the Proponent submitted an addendum document based on new learnings from the H Sand dynamic performance, titled:

- Hebron Development Plan Amendment Addendum 2023 – Jeanne d'Arc Formation Sand Intervals.

This addendum is also considered part of the Application.

With respect to industrial benefits, in consultation before filing the Application, staff determined that a Benefits Plan Supplement would be appropriate for the amended activities. As a result, the Hebron Benefits Plan will apply to the Application and reflects a continuing obligation for the activities described in the Application.

On March 2, 2023, the C-NLOPB invited public comments on the Application with responses due on March 31, 2023. The one submission and response arising from the public review process were taken into account by staff in analysis of the Application and the resulting recommendations to the Board.

Staff reviewed the Application from the perspective of safety, environmental protection, industrial benefits resource management and operations. The following is a summary of this review.

Safety

Activities in connection with this Application will be managed in accordance with established safety plans, procedure and applicable processes. There are no additional safety issues identified.

Protection of the Environment

The Hebron Project was subject to an Environmental Assessment pursuant to the *Canadian Environmental Assessment Act* (1992). The Comprehensive Study was released by the federal Minister of Environment on December 22, 2011. Additionally, the Proponent has submitted a Comprehensive Study Report (CSR) Addendum (2013), and an Environmental Assessment (EA) Amendment (2017). The additional development activities described in the Application do not represent a substantive change in operations, and the environmental issues/effects and associated mitigation measures (as reflected in the CSR and subsequent EA submissions) remain applicable to the nature and scope of the activities described in the Application.

Industrial Benefits

In April 2012, the Proponent's Hebron Benefits Plan was approved. This Plan detailed the Proponent's commitments respecting s.45 of the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Act* in relation to the entire Hebron Project. The Hebron Benefits Plan contains several commitments related to procurement and employment and is subject to C-NLOPB oversight. For this particular Application, staff conducted numerous discussions with the Proponent and analyzed its procurement and employment plans. Based on its analysis, staff determined that a Hebron Benefits Plan Amendment was not required and recommend approval. All activities will be managed in accordance with the Proponent's approved Hebron Benefits Plan.

Resource Management

In assessing the resource management aspects of the Application, staff reviewed the Proponent's seismic interpretation, geological model and reservoir simulation model. Staff also conducted a review of geological, petrophysical and production data acquired since approval of the Hebron Development Plan (Decision Report

2012.01). Staff constructed an independent geological model to assess in-place resources; however, did not construct independent simulation models.

At the time of Development Plan submission (Decision Report 2012.01), the I-13 and M-04 delineation wells were the only JDA Formation well penetrations, and the H Sand was only encountered in the M-04 well. Both the Proponent and staff acknowledged a high degree of uncertainty regarding reservoir quality and connectivity in the JDA Formation. This uncertainty led to the Proponent proposing development of only the H and B sands. Oil accumulations had also been encountered in the G and D sands, but both sands were classified as contingent developments by the Proponent. The C-NLOPB expected the Proponent to acquire more data to optimize the depletion plan for the JDA and agreed that these sands should be classified as deferred developments.

In 2020, the Proponent requested approval to conduct an extended formation flow test in the first producer (L-93 22) in the JDA Formation, to evaluate the dynamic performance of the reservoir and reduce reservoir property uncertainties. The static and dynamic data collected from the L-93 22 well during the extended formation flow test was incorporated into geologic and simulation models for the JDA Formation sands. These models were used to update the development strategies for each sand and provided insight into remaining uncertainties that will require additional future data collection.

In 2022, the Proponent submitted a proposal to the C-NLOPB regarding pooling in the JDA Formation, based on evaluation of geologic and pressure data and analysis of reservoir connectivity. After detailed review by staff, the Chief Conservation Officer accepted the proposal and designated seven separate pools in the JDA Formation.

The Application proposes development of the remaining sands located stratigraphically between the H and B sands. Staff agree that additional reserves added by inclusion of currently undeveloped sands will assist in offsetting the natural decline in production at Hebron and this is the next step to optimizing Hebron area resources, consistent with good oil field practice.

Staff reviewed the Proponent's models and agreed that they represent reasonable interpretations of the resources in place and the expected reservoir behaviour.

Staff assessed EUR for the JDA Formation sands based on geologic modelling and reservoir data. As a result, staff now expect a proved and probable EUR of 26.3 MMm^3 (165.3 MMbbl). This estimate is an increase from C-NLOPB's previous assessment of 21 MMm^3 (132 MMbbl) at the time of Hebron Development Plan (Decision Report 2012.01) approval.

Based on its assessment, staff concur with the Application from a resource management perspective, and recommend approval.

Operations

The JDA Formation well count is increased to 12 production wells and five water injection wells inclusive of commingled wells and wells in the "Prime" blocks to develop the B through H sands. The wells are achievable using existing facilities, well slots, recovery methods and systems, and no infrastructure-related modifications are required to the *Hebron* Platform to construct them. All work outlined as part of the Application is consistent with and captured under the currently approved Scope of Work for the *Hebron* Installation.

Well-specific details regarding hole sizes, casing, cementing design and completion strategies will be evaluated through the Approval to Drill a Well process. Any proposed change in well service will be evaluated through the Approval to Alter the Condition of a Well process. Should any new technologies or applications be proposed for use on the *Hebron* Platform, or should any change in service of a well be requested, the Proponent would need to ensure that its application for Operations Authorization addresses the modifications, in addition to all other regulatory requirements pertaining to the authorization and approval process.

Conclusion

Staff are recommending approval of the Application, subject to the following conditions:

Condition 1: Recognizing the limited availability of remaining drill slots on the Hebron Platform, the Proponent must describe efforts to reduce slot constraints through updates to the Resource Management Plan on an ongoing annual basis and in regular semi-annual subsurface meetings with Resource Management staff.

Condition 2: The Proponent must continue efforts to de-risk the “Prime” blocks and other upside resources in the Jeanne d’Arc Formation and provide details of this work in the annual update to the Resource Management Plan and in regular semi-annual subsurface meetings with Resource Management staff.

Condition 3: The Proponent must continue efforts to evaluate Pools 2 and 3 and other upside resources and provide details in the annual update to the Resource Management Plan and in regular semi-annual subsurface meetings with Resource Management staff. The Proponent must submit a report to the Regulator within two years of this Decision Report that explains plans to de-risk development of Pools 2 and 3.

2. Purpose

The purpose of this document is to provide the Board with an assessment of the application received from ExxonMobil Canada Properties (Proponent) to amend the Hebron Development Plan. The Proponent plans to develop the remaining reservoirs within the Jeanne d'Arc (JDA) Formation at the Hebron Field. This analysis considered environmental protection, industrial benefits, resource management, operations and safety aspects of the application.

3. Background

3.1. The Application

The following describes the documents that have been submitted seeking approval of a Development Plan Amendment (DPA) for the Hebron Field.

On November 18, 2022, the Proponent submitted to the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) on behalf of its coventurers Chevron Canada Limited, Suncor Energy Inc., Equinor Canada Limited, and Nalcor Energy - Oil and Gas Inc., the following document:

- Hebron Development Plan Amendment 2022 – Jeanne d'Arc Formation Sand Intervals.

Staff reviewed this document for completeness and requested additional information in a letter dated January 17, 2023. The Proponent responded to this request by submitting the following documents on February 3, 2023:

- Hebron Development Plan Amendment 2022 Jeanne d'Arc Formation Sand Intervals – Revision;
- Hebron Development Plan Amendment 2022 - Jeanne d'Arc Formation Sand Intervals – Change Registry;
- Hebron L-93 29 - Reservoir Fluids Report - Modular Formation Dynamics Tester Samples - F Sand;
- Hebron L-93 29 - Reservoir Fluids Report - Pressure Volume Temperature Study - Modular Formation Dynamics Tester Samples - C Sand;
- Hebron L-93 29 - Reservoir Fluids Report - Pressure Volume Temperature Study - Modular Formation Dynamics Tester Samples - B Sand;
- Hebron L-93 29 - Reservoir Fluids Report - Water Analysis;
- Hebron L-93 30Z - Reservoir Fluid Report - Produced Water.

Staff reviewed the revised documents and determined that the Application was complete.

On July 19, 2023, the Proponent submitted an addendum document based on new learnings from the H Sand dynamic performance, titled:

- Hebron Development Plan Amendment Addendum 2023 – Jeanne d'Arc Formation Sand Intervals.

This addendum is also considered part of "the Application".

With respect to industrial benefits, in consultation before filing the Application, staff determined that a Benefits Plan Supplement would be appropriate for the amended activities. As a result, the Hebron Benefits Plan will apply to the Application and reflects a continuing obligation for the activities described in the Application.

On March 2, 2023, the C-NLOPB invited public comments on the Application with responses due on March 31, 2023. The results of the public review are discussed in section 3.3.

3.2. History / Context

The Hebron Field is located on the Grand Banks, approximately 340 km offshore St. John's, Newfoundland and Labrador and approximately 9 km north of Terra Nova Field, 32 km southeast of Hibernia Field and 46 km southwest of White Rose Field (Figure 1). The water depth ranges from 88 to 102 m.

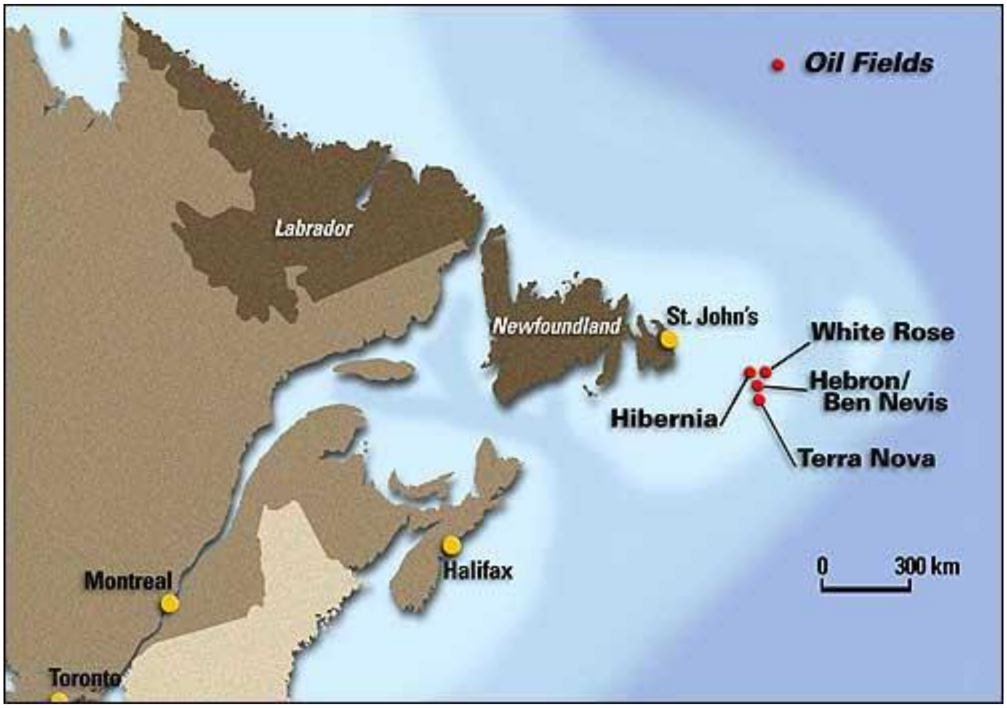

Figure 1: Hebron Field location (Source: ExxonMobil Canada Properties, 2022)

Initially considered three separate fields, the term "Hebron Asset" is used by the Proponent to describe the Ben Nevis, West Ben Nevis and Hebron discoveries collectively. After approval of the Hebron Development Plan in 2012 (Decision 2012.01), the fields previously considered part of the Hebron Asset were designated as a single field by the Chief Conservation Officer (CCO) in 2017 prior to the start of production.

The initial discovery was in 1980, by the drilling and testing of the Ben-Nevis I-45 well (Figure 2). The I-45 discovery was followed by two phases of delineation drilling. In the first phase of delineation drilling, the Hebron I-13 well was drilled in 1981 to assess the Hibernia and Jeanne d'Arc (JDA) formations at the structurally highest point of the fault block and to test the oil in these reservoirs. The well also penetrated the Ben Nevis Formation in the downthrown fault block to the south and tested oil. The West Ben Nevis B-75 well was drilled in 1985 to evaluate the fault block between the I-45 and I-13 wells. This well tested oil in the Ben Nevis Formation, A Marker Member and JDA Formation.

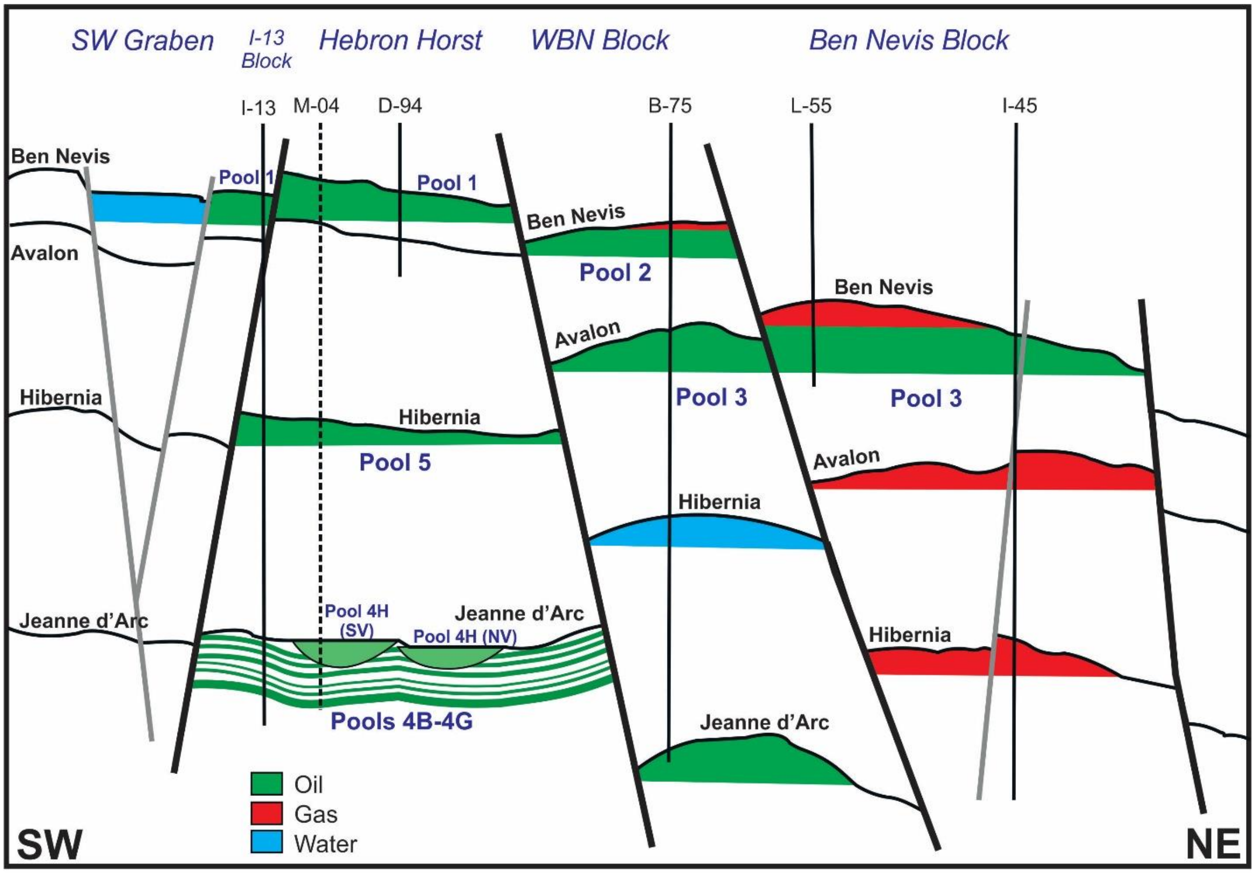

Figure 2: Schematic cross-section across the Hebron Project Area

A second phase of delineation drilling began in 1996 to test if there was an economic upside to the Hebron Project area. The D-94 well was drilled to test the Ben Nevis Formation on the 'Hebron Horst' fault block in early 1999. The well encountered over one billion barrels stock-tank original oil in place (STOOIP) and better reservoir and oil quality than observed in the I-13 well. The D-94 well encountered the same oil-water contact (OWC) as identified in the I-13 well, indicating that the I-13 fault block was in communication over geologic time with the D-94 fault block. The Ben Nevis L-55 well was drilled in 1999 to evaluate the potential for higher structure and better reservoir quality in the Ben Nevis Formation of the Ben Nevis fault block. The well encountered the top of reservoir in a structurally higher position than the I-45 well and confirmed a gas cap in the pool. The Hebron M-04 well was drilled in 2000 to investigate an incised valley-fill feature identified on seismic at the top of the JDA horizon (H Sand) and to extend evaluation and gather additional data on the Ben Nevis, Hibernia and JDA pools. The well tested oil in the Ben Nevis and JDA H Sand.

At the time of Development Plan approval (Decision Report 2012.01), the I-13 and M-04 delineation wells were the only JDA Formation well penetrations and the H Sand was only encountered in the M-04 well. Both the Proponent and staff acknowledged a high degree of uncertainty regarding reservoir quality and connectivity in the JDA Formation. This uncertainty led to the Proponent proposing development of only the H and B sands. Oil accumulations had also been encountered in the G and D sands, but both sands were classified as contingent developments by the Proponent. The C-NLOPB expected the Proponent to acquire more data to optimize the depletion plan for the JDA and agreed that these sands should be classified as deferred developments.

Production from the Hebron Field began in November 2017 from Production Licence (PL) 1012, which includes Ben Nevis, Hibernia and JDA formations. The Hebron Development Plan (Decision Report 2012.01) included development of the H and B sands in the JDA Formation, with all other JDA sands listed as deferred developments containing contingent resources. Thirty-one development wells have been drilled in the Hebron Field to date: 20 oil producers, seven water injectors and four gas injectors. Two of the oil producers were drilled in the JDA Formation. As of August 2023, 39.4 MMm^3 (247.6 MMbbl) of oil has been produced from the Hebron Field with 0.44 MMm^3 (2.7 MMbbl) coming from the JDA Formation. The production history of the Hebron Field is shown in Figure 3.

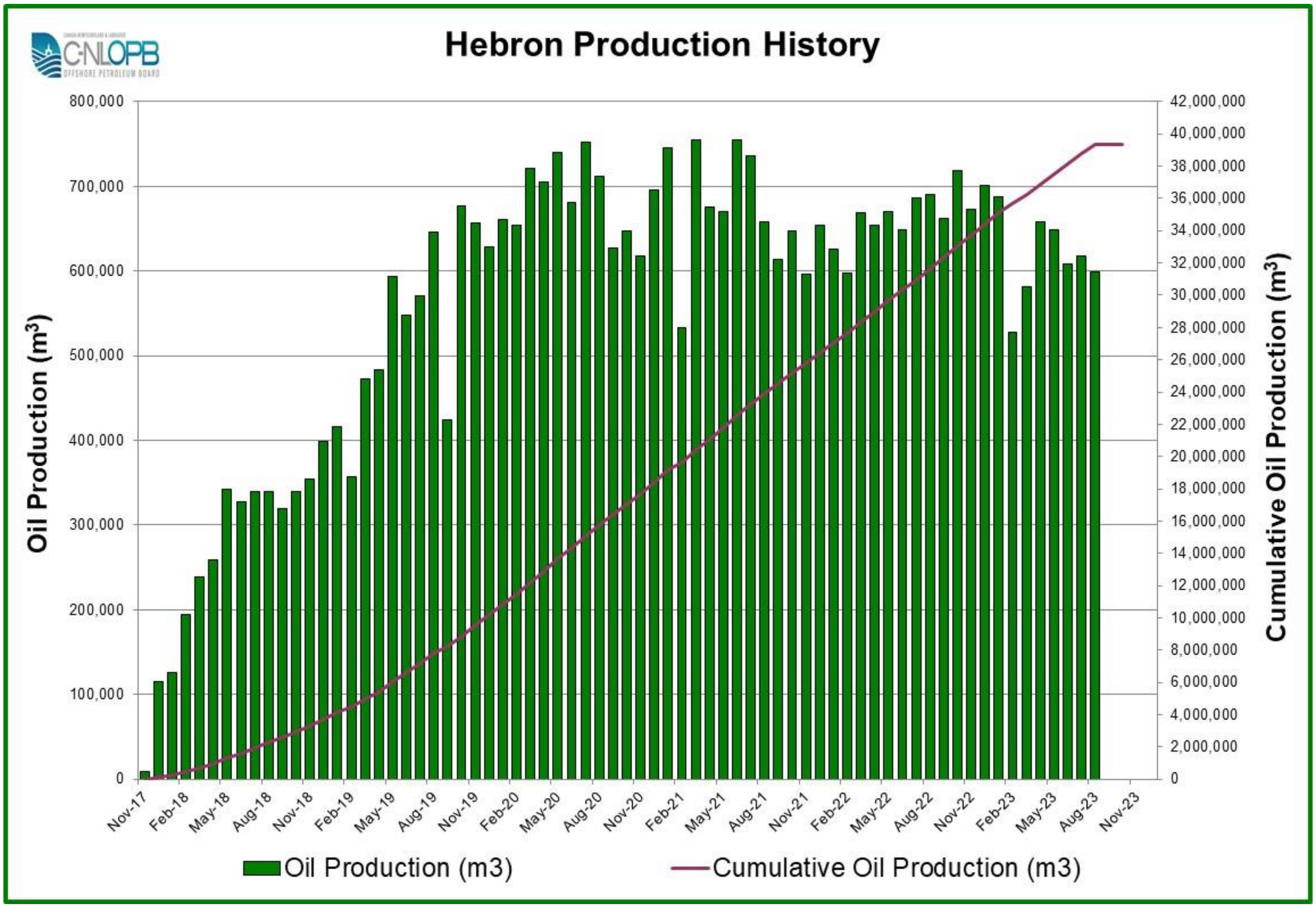

Figure 3: Production history of Hebron Field

In 2020, while planning the first H Sand development well, L-93 22, the Proponent opted to deepen the well to acquire additional static and dynamic data from the B Sand and other oil-bearing sands. The well encountered oil accumulations in the G and E sands. The Proponent applied for a temporary extended flow test for these sands to acquire dynamic data to inform a decision on potential future development. An extended flow test for a period of one year was granted in 2020. The static and dynamic results acquired from L-93 22, including the extended flow test, helped reduce uncertainty and contributed to better understanding of the JDA Formation, as detailed in the Application.

In 2021, the Proponent deepened the first Hibernia Formation producer to acquire static data in the JDA South Valley prospect with the L-93 29Y delineation well. The South Valley was identified by the Proponent as a “prospect” in the Development Plan (Decision Report 2012.01) as it did not contain a well penetration at the time. L-93 29Y was successful in finding a high-quality C Sand while also finding smaller oil accumulations in the H and B sands. It was the first well to encounter an oil bearing C Sand in the JDA Formation, which led to the proposed development in the Application.

The second H Sand producer, L-93 30Z, came online in June 2022. The addendum, submitted on July 19, 2023, included learnings from the L-93 30Z dynamic data and the resulting updated strategies the Proponent is pursuing to balance uncertainty and data collection.

In 2022, the Proponent submitted a proposal to the C-NLOPB regarding pooling in the JDA Formation, based on evaluation of geologic and pressure data and analysis of reservoir connectivity. After detailed review by staff, the CCO accepted the proposal and designated seven separate pools in the JDA Formation. It is recognized that hydrocarbon accumulations within the JDA Formation extend onto Production Licences (PLs) 1003 and 1004. The Commercial Discovery Area includes the relevant sections in Significant Discovery Licence (SDL) 1006, SDL 1046, SDL 1042, PL 1003 and PL 1004 (Figure 4).

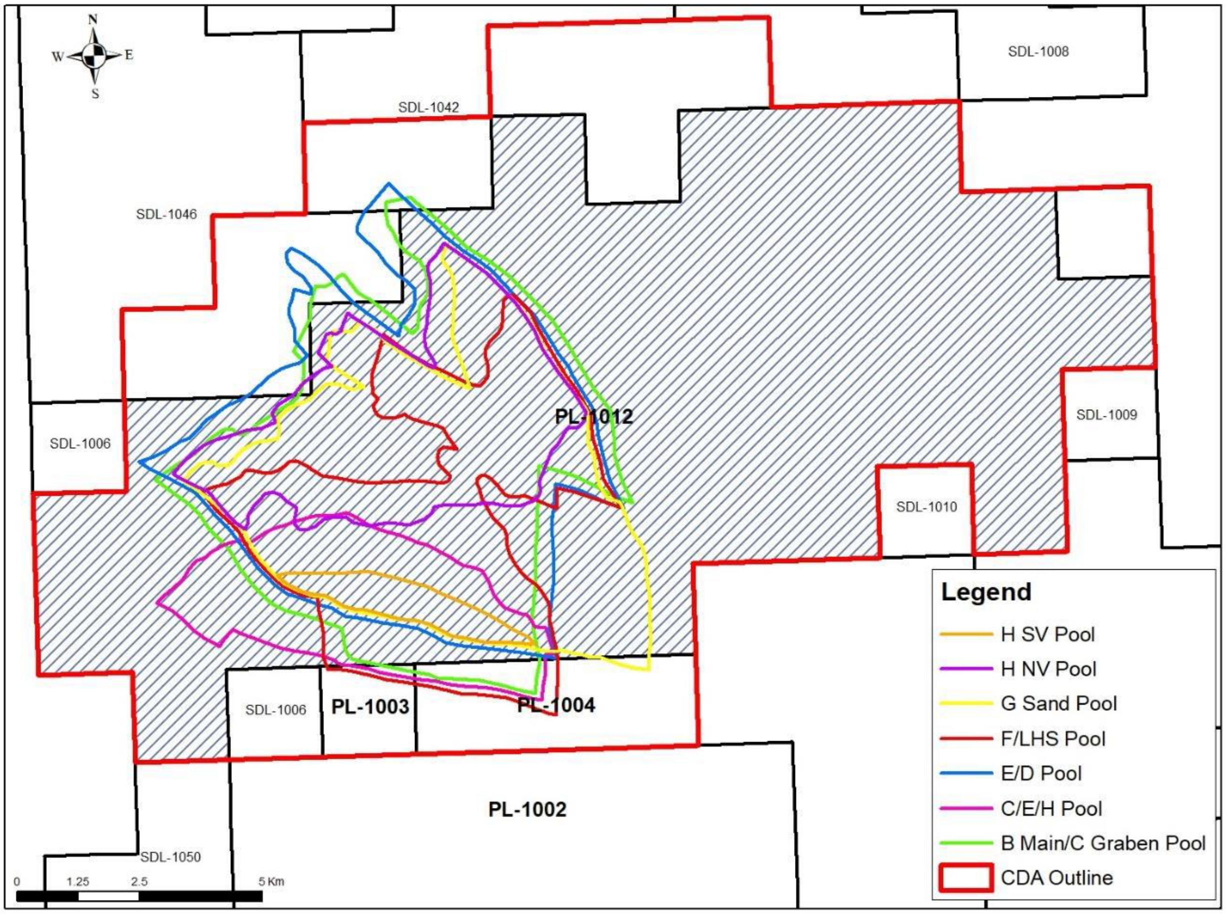

Figure 4: Hebron licence boundaries and Jeanne d'Arc Formation individual pool outlines (Source: ExxonMobil Canada Properties, 2022)

The optimized development of the JDA Formation and the capture of additional resources through the inclusion of currently undeveloped sands will assist in offsetting the natural decline in production at Hebron and is the next step to optimizing Hebron resources, consistent with good oil field practice.

3.3. Public Review

Section 44(1) of the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Act* (Accord Act; Federal Version) states that:

44. (1) Subject to any directive issued under subsection 42(1), the Board shall conduct a public review in relation to any potential development of a pool or field unless the Board is of the opinion that the public hearing is not required on any ground the Board considers to be in the public interest.

The C-NLOPB's interpretation of section 44(1) is described in its Development Plan Guideline, which indicates that the scale and scope of the public review should be commensurate with the scale of the development and the degree to which new and innovative techniques and approaches are proposed. In other words, the public review process is best determined on a case-by-case basis.

In respect of this Application, the Board decided to hold a 30-day web-based public consultation. The public review for the Application began on March 2, 2023, and closed on March 31, 2023.

The Public Review did not include a review of the Environmental Assessment, as the additional development activities described in the Application did not require an amendment to the Environmental Assessment. The Hebron Project was subject to an Environmental Assessment pursuant to the *Canadian Environmental Assessment Act* (1992) and was released by the federal Minister of Environment in December 2011.

One submission from Fish, Food & Allied Workers (FFAW)-Unifor was received during the public review process. As the Operator of the proposed Amendment, the Proponent responded on June 12, 2023 to questions and comments that were specific to the Proponent, and C-NLOPB staff responded to questions and comments specific to the C-NLOPB on June 27, 2023. Questions and comments and subsequent responses from both the Proponent and the C-NLOPB are as follows:

FFAW Comment: "Fishing activities or patterns have often been forced to change because of oil and gas developments in the offshore, therefore, it is inaccurate to say that this additional development will not have an impact on fisheries and the people who depend on them."

Proponent Response: ExxonMobil is committed to forums such as One Ocean, which has been successful for over 20 years at connecting ocean users to mitigate cross-industry impacts. Included in One Ocean's mandate is to "facilitate effective communication, cooperation and transparency to enhance safe practices and successful coexistence in a shared marine environment." Additionally, the Hebron Project's strong environmental performance has been supported by efforts to improve the consistency and quality of produced and drainage water discharges, and Environmental Effects Monitoring has shown no significant impacts, consistent with original predictions from environmental assessment work.

FFAW Comment: "A concern for harvesters regarding this development application is the potential for the expansion of safety zones surrounding additional drilling installations. When the original "safety" zones were designated around the drill rig, the temporary loss of fishing access appeared relatively small. However, activity within this area has grown and now continues to grow. Plans to develop Hebron sands in the coming years are now evident and exclusion zones to fishing may grow larger, too. When discussing impacts related to drilling and production, it is important to consider not only the footprint of the drilling, but how the associated activities interact with and displace fishing activity."

Proponent Response: The safety zone is in accordance with governing legislation and remains unchanged. Activities associated with the Hebron Development Plan Amendment 2022 will use existing drilling and production facilities, equipment, and procedures to access resources within the pre-existing operational footprint from the Hebron GBS. Supporting vessel traffic, including tankers, supply vessels and other maintenance vessels, will be similar to current traffic under active drilling operations.

FFAW Comment: "The acquisition of new seismic data is mentioned in this Amendment on page 111."

Proponent Response: The Hebron Development Plan Amendment 2022 utilizes existing seismic and well data to identify and characterize hydrocarbon zones not previously included in the Hebron Development Plan (2011). The hydrocarbon zones are sufficiently characterized by the current seismic data such that no additional seismic data acquisition is proposed. Due to the nature of seismic data, any data collected in and around Hebron may include hydrocarbon zones in the Hebron Development Plan Amendment 2022 and would be utilized. No additional seismic activities are planned as part of this Development Plan Amendment, however, should seismic data be collected in the area, ExxonMobil would follow applicable regulations and existing engagement processes (e.g. via One Ocean) to ensure best practices are followed.

FFAW Comment: "Frequent and transparent communication between ExxonMobil representatives and the fishing industry with respect to this Development Plan is critical."

Proponent Response: As previously mentioned, ExxonMobil remains committed to transparent dialogue on activities at the One Ocean table as a key means to ensure all ocean users are informed of ongoing activities. Additionally, a meeting between ExxonMobil Canada Properties and the FFAW was held on May 4, 2023 to discuss the Development Plan Amendment scope. ExxonMobil remains available for additional meetings should the FFAW have further questions or comments.

FFAW Comment: "Significant planning and spending will be required to phase away from oil and prepare for the end of project life at Hebron." and "We recommend the C-NLOPB prioritize decision-making for renewable industries, such as the fishing industry, as it will likely serve as more economically responsible moving forward."

C-NLOPB Response: The C-NLOPB values the input of FFAW-Unifor and, as we have indicated previously, we carefully consider your perspective in delivering our regulatory responsibilities in the public interest. We know from past and recent engagements with FFAW-Unifor that its membership and its leadership recognize that successful, environmentally responsible fisheries and energy sectors are of critical importance to the province, as well as the need for both industries to co-exist in our one ocean. At the C-NLOPB, we continue to prioritize frequent and meaningful engagement with FFAW-Unifor, directly and via the One Ocean forum, on matters of mutual interest. We also continue to reinforce with companies operating, or planning to operate, in our offshore area the importance of engaging with fishery stakeholders early and often regarding their plans.

FFAW Comments: The recently released 2023 Provincial Budget has allocated $13 million for the acquisition and processing of new seismic data. It has been documented in peer reviewed literature that seismic survey activity may result in behavioural changes among fish species. While these changes have been reported to be temporary, avoidance, startle responses and changes in swimming speed and direction can all have an impact on commercial fishing activities taking place at finite times (i.e. seasons) in finite spaces (i.e. fishing areas). The fishing industry has already witnessed catch rates drop immediately after a seismic vessel has entered an area where fishing is taking place, directly impacting economic return." and "The fishing industry contends that critical data gaps exist in the research regarding seismic activity and behavioural changes of fish/shellfish. These changes may affect migration and/or reproductive and spawning activities as well as movement of the exploitable biomass in an area."

C-NLOPB Response: C-NLOPB staff work closely with subject matter experts at Fisheries and Oceans Canada and other government agencies in Canada and internationally, to obtain the most up to date science and evidence regarding the potential risks associated with seismic activity, offshore petroleum exploration and production. These ongoing efforts inform our regulatory oversight of operators, who must reduce those risks to levels that are as low as reasonably practicable.

All questions, comments and responses arising from the public review process were taken into account by C-NLOPB staff in analysis of the Application and recommendation to the Board.

4. Safety

Activities in connection with this Application will be managed in accordance with established safety plans, procedures and applicable processes. There are no additional safety issues identified.

4.1. Recommendation

The Safety Department staff recommend approval of this Application.

5. Protection of the Environment

Staff reviewed the Application to determine: whether the work raises any new environmental issues that were not considered in the original environmental assessments; whether it changes the impacts associated with issues considered in the original assessments in a manner that exceeds those effects previously predicted; and whether the impacts of the work would be within regulatory limits, which may have changed since Decision 2012.01. This review considered previously completed environmental assessments and Decision Reports.

The Hebron Project was subject to an Environmental Assessment (EA) pursuant to the *Canadian Environmental Assessment Act* (1992). The Comprehensive Study was released by the federal Minister of Environment on December 22, 2011. Additionally, the Proponent submitted a Comprehensive Study Report (CSR) Addendum (2013) and an EA Amendment (2017). The scope of the 2013 addendum included activities associated with 3D seismic surveys. The scope of the 2017 amendment assessed modification to the disposal of synthetic based drilling mud (SBM) associated with drill cuttings.

The additional development activities described in the Application do not require changes to the installations and equipment deployed in the field, operations, shipping activities or the extent of safety zones. The total number of wells (52) proposed for the Hebron Project and produced water discharge rates are estimated to remain within ranges described in the CSR. Those wells will be drilled from the GBS and will not require the construction of excavated drill centres or the operation of MODUs, although those activities were assessed in the original CSR. On this basis, the impact of the physical presence in the environment associated with the amendment is deemed to fall within the impact assessed in the CSR.

The facility was designed to accommodate an estimated production rate of 23,900 m^3/day of oil (150 kbd), with a potential throughput after de-bottlenecking and production optimization of 28,600 m^3/day (180 kbd). The produced water system was designed to process and discharge up to 56,000 m^3/day (approximately 350 kbd) of produced water. Gas handling was designed to handle up to 8,500,000 m^3/day (300 MMscf/d) to accommodate gas re-injection and artificial lift gas.

4.1 Greenhouse Gas Emissions

At the time of the CSR, greenhouse gases (GHGs) were considered under the Air Quality Valued Ecosystem Component (VEC) and the spatial boundary was considered as global. GHG emissions associated with power generation, gas compression, flaring and fugitive emissions were considered in the CSR. In considering the impact of greenhouse gas emissions, the CSR followed guidance from the Canadian Environmental Assessment Agency (CEAA). GHG emissions for the project were considered by conducting a preliminary scoping of GHG emissions, determining the industry profile (where possible), and by considering the magnitude, intensity and duration of project emissions as directed by the CEAA guidance. Project-related GHG emissions were also compared to similar projects, and to provincial and national greenhouse gas emissions.

In the CSR, normal operational GHG emissions were estimated to be 596,469 tonnes of CO_2eq per year.

Table 1: Hebron Project Comprehensive Study Report - Estimated Greenhouse Gas Emissions

Function	Greenhouse Gas Emissions (tonnes CO_2eq per year)			
	CO_2	N_2O	CH_4	Total
Power Generation	269 024	19.9	5	275 298
Gas Compression	174 612	6.7	3.3	176 758
Flaring	92 849	0.173	484	103 067
Fugitive Emissions	-	-	1 346	28 266
Vessel Traffic	12 589	-	-	12 589
Helicopter Traffic	491	-	-	491
Total				596 469
Source: Hebron Project Comprehensive Study Report, pages 6-30				

Table 2: Hebron Project – Reported Greenhouse Gas Emissions

Year	Greenhouse Gas Emissions (tonnes CO_2eq)			
	CO_2	CH_4	N_2O	Total
2018	400 088	78 210	3 151	481 449
2019	517 219	85 621	2 805	605 645
2020	481 622	26 099	3 032	510 753
2021	437 227	14 113	3 302	454 643
Source: NL-Industrial-Facilities-Provincial-GHG-Data-for-Website-2016-2021.pdf (gov.nl.ca) as of January 12, 2023				

The CSR stated that the emissions expected from the Hebron Project were similar in magnitude to similar activities in similar jurisdictions, but that "…it is not yet possible to determine the effect of these emissions on climate change." It remains true that the impact of project specific emissions on global climate change are not well determined, but it is reasonable to suggest that an increase in GHG emissions with respect to those previously assessed is an undesirable change in the context of Canada's Federal and Provincial commitments with respect to GHG emissions.

Since the start of production in 2017, the Proponent has implemented changes to its operations to reduce GHG emissions, including improvements in gas injection compressor reliability, updates to gas injection strategies and refinements in operational practices. This has resulted in an estimated 77% reduction of GHG emissions from flaring between 2019 and 2021. Hebron has also implemented an optical imaging Leak Detection and

Repair (LDAR) program to identify and mitigate fugitive emissions. (See the C-NLOPB 2022 Annual Emissions Reduction Initiative Report at https://www.cnlopb.ca/wp-content/uploads/emrep/emrep2022.pdf.)

Based on the information in the Application, GHG emissions are expected to remain below the emissions estimate (596 kTCO2e/year) described in the CSR (in a range of from 500-596 kT CO2e/year). On this basis, GHG emissions associated with the amendment are deemed to fall within the impact assessed in the CSR.

A graph showing the trend in carbon intensity of oil produced from the Hebron Field is shown in Figure 5.

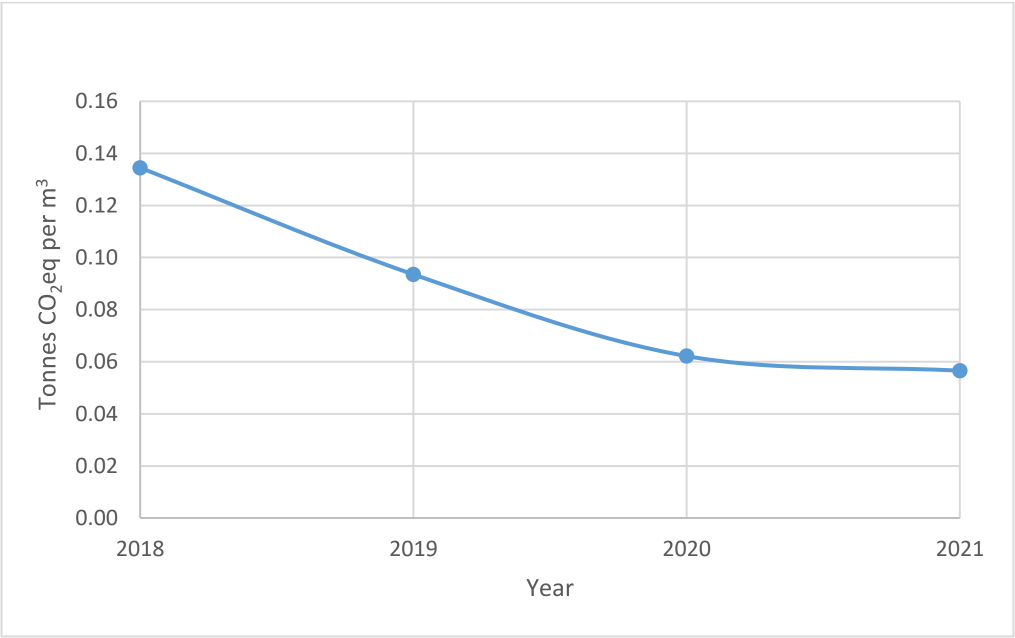

Figure 5: Carbon intensity of oil produced from the Hebron field since 2018. Vertical axis represents tonnes of CO_2 equivalent emitted per m^3 of oil produced. (Source: C-NLOPB data)

The activities proposed in the Application will not require modification to the Environmental Compliance Monitoring Plan nor the Environmental Effects Monitoring Program.

4.2 Recommendation

No environmental concerns were identified that would preclude staff from recommending approval of the Application. Activities in connection with the Application can be managed in accordance with established processes and procedures.

The Environmental Protection Department staff recommend approval of this Application.

6. Industrial Benefits

Staff reviewed the Application in the context of the benefits-related obligations in the Accord Act, as well as the Proponent's approved Hebron Benefits Plan. In particular, staff analyzed the Application to determine whether any new industrial benefits would accrue in Canada, and in particular within the province, from the Proponent's planned scope of activities. As part of its review, staff held multiple meetings with the Proponent and reviewed the Proponent's employment and contracting plans to inform the analysis.

With respect to procurement and contracting, it was determined that the proposed scope of activities will be executed mainly using contracts that were already awarded through regular Hebron Project operations, and in accordance with the Proponent's approved Hebron Benefits Plan. Any additional contracting activity will be subject to the commitments and principles of the Proponent's Hebron Benefits Plan and C-NLOPB oversight. The Hebron Benefits Plan details that companies within the province and other parts of Canada, will have a full and fair opportunity to compete for Hebron Project contracts, and that first consideration will be given to goods manufactured within and services provided from within the province, where they are competitive in terms of fair market price, quality and delivery.

Respecting employment, staff determined that the scope of activities will be completed using existing staff and contractor personnel that were hired through regular Hebron Project operations, and in accordance with the Proponent's approved Hebron Benefits Plan. Similar to procurement and contracting, staff were assured that any new employment opportunities would be subject to the commitments and principles of the Proponent's Hebron Benefits Plan and C-NLOPB oversight. The Hebron Benefits Plan details that individuals resident in the province of Newfoundland and Labrador will be given first consideration for employment opportunities for the Hebron Project, and that such opportunities will be advertised externally to ensure public awareness.

6.1. Recommendation

Through review of the Application and consultations with the Proponent, staff determined that a Benefits Plan Amendment was not required and did not identify any issues that would preclude our recommendation of approval of the Application. The scope of activities detailed within the Application will be completed through existing Hebron Project staff and contracts. As well, the principles and commitments highlighted throughout the Proponent's approved Benefits Plan will continue to apply to all activities.

7. Resource Management

Staff reviewed the Application, including the Proponent's seismic interpretation, geological model and reservoir simulation model. Staff also conducted a review of geological, petrophysical and production data acquired since approval of the original Hebron Development Plan in 2012 (Decision 2012.01).

Staff constructed an independent geological model but did not construct independent simulation models.

7.1. Geology, Geophysics and Petrophysics

7.1.1. Regional Geology

The Application provides a summary of the Hebron Field geology and includes a brief description of the stratigraphic sequence and fault blocks. Considering that the general understanding of the area has not changed since submission of the Hebron Development Plan (Decision Report 2012.01), a detailed discussion is not required for the Application.

The structural divisions of the Hebron Field are based on the structural map of Ben Nevis Formation, as this is the primary reservoir in the Hebron Field. The five major fault blocks are shown in Figure 6. At the level of the JDA Formation, increased faulting has resulted in additional fault blocks denoted A' to F' (collectively referred to as the "Prime" blocks), rimming the eastern and southern parts of the Hebron Horst as shown in Figure 7.

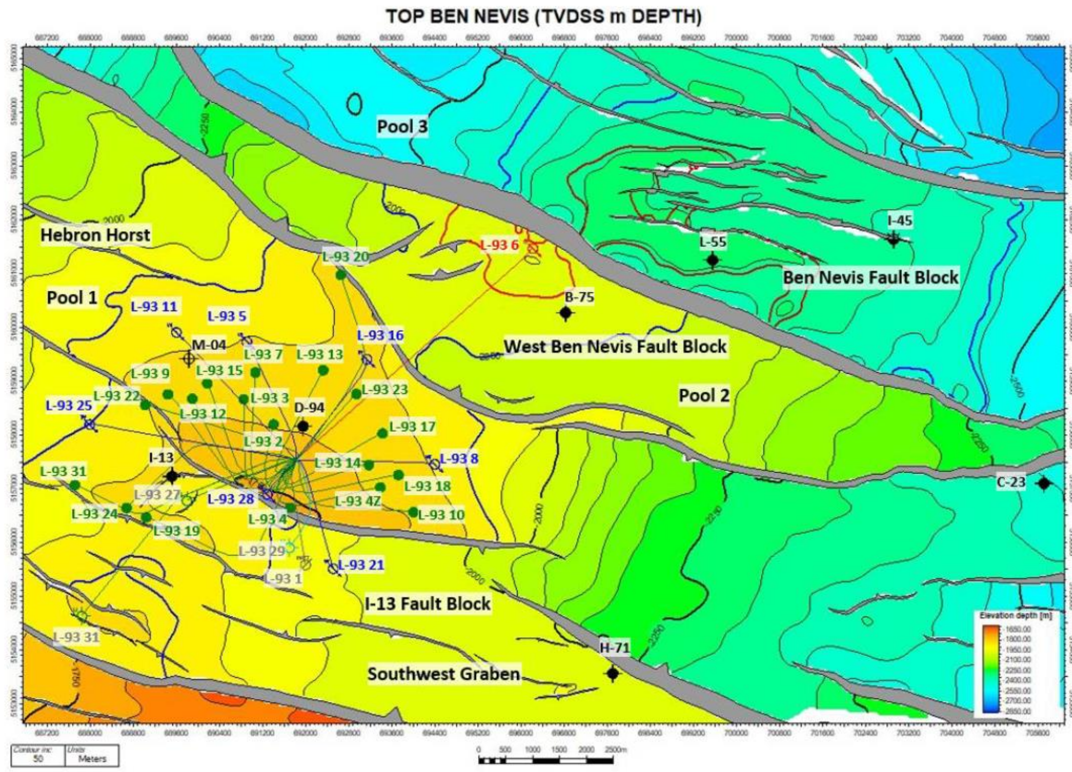

Figure 6: Structure map on top Ben Nevis Formation showing the five main Hebron fault blocks: Southwest Graben, I-13 Fault Block, Hebron Horst, West Ben Nevis Fault Block and Ben Nevis Fault Block (Source: ExxonMobil Canada Properties, 2022)

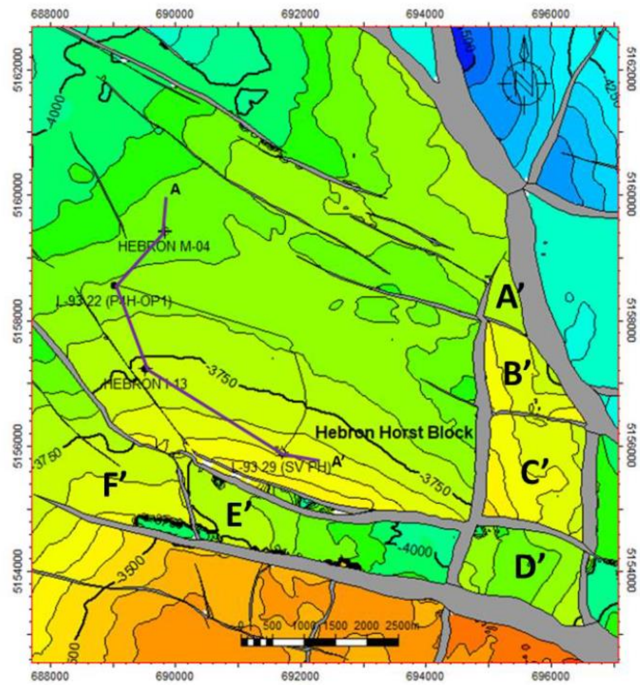

Figure 7: Structure map on top JDA Formation, showing "Prime" blocks (A'-F') adjacent to the Hebron Horst (Source: ExxonMobil Canada Properties, 2022)

7.1.2. Jeanne d'Arc Formation Geology

The JDA Formation is the deepest producing reservoir in the Hebron Field. The same reservoir at Terra Nova Field has a higher net–to-gross ratio, is coarser grained and is more proximal in the depositional system. The formation is interpreted as a thick succession (up to 650 m), containing multiple fine- to coarse-grained sandstones. The most significant sand intervals from top to bottom are: H, G, F, E/D, C, BC stringers and B sands.

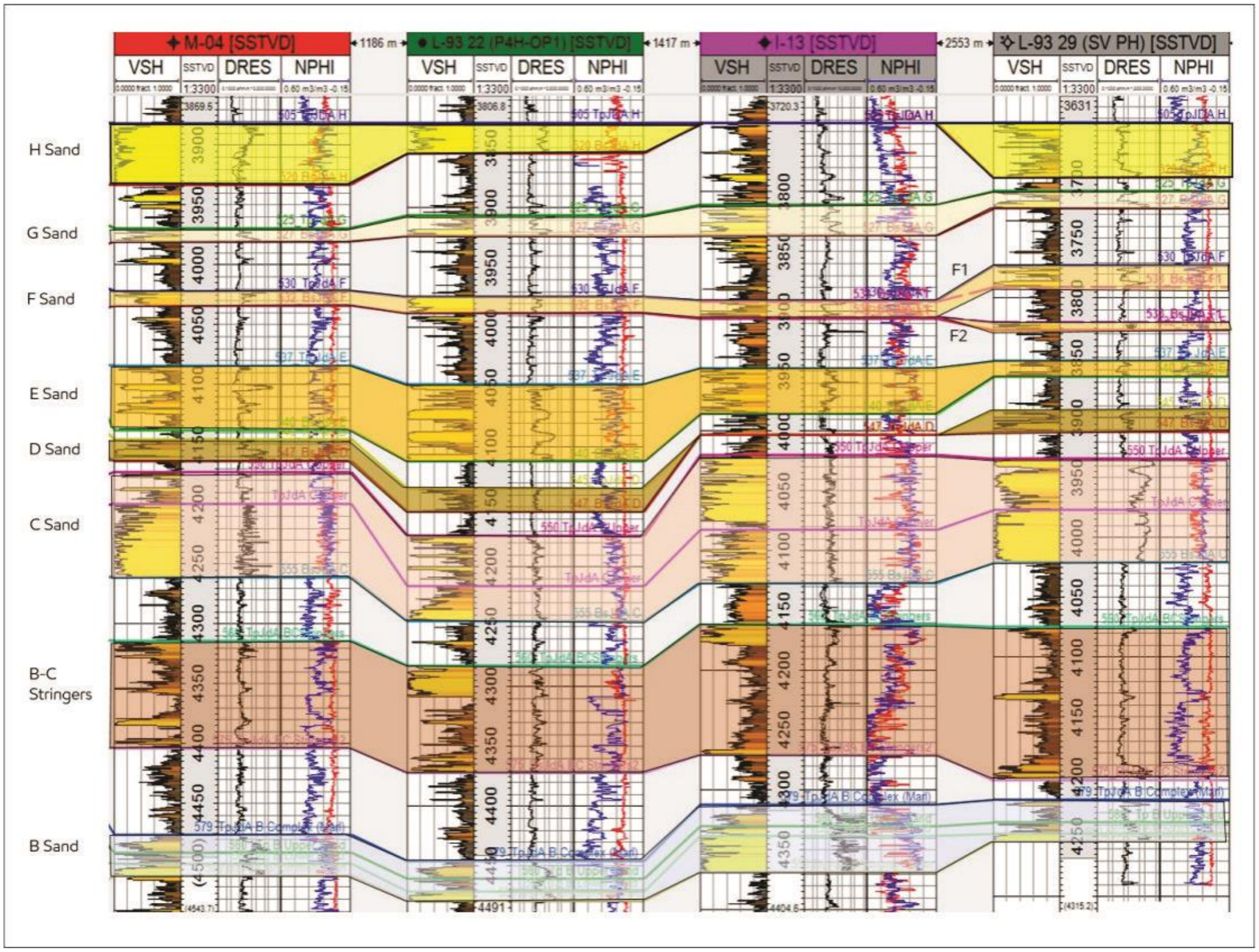

Figure 8 shows the stratigraphic positions and correlations of the various sand units. Individual sand units are not all directly correlatable across the area due to the fluvial channel environment of deposition (EOD) which resulted in some discontinuity in reservoir deposition.

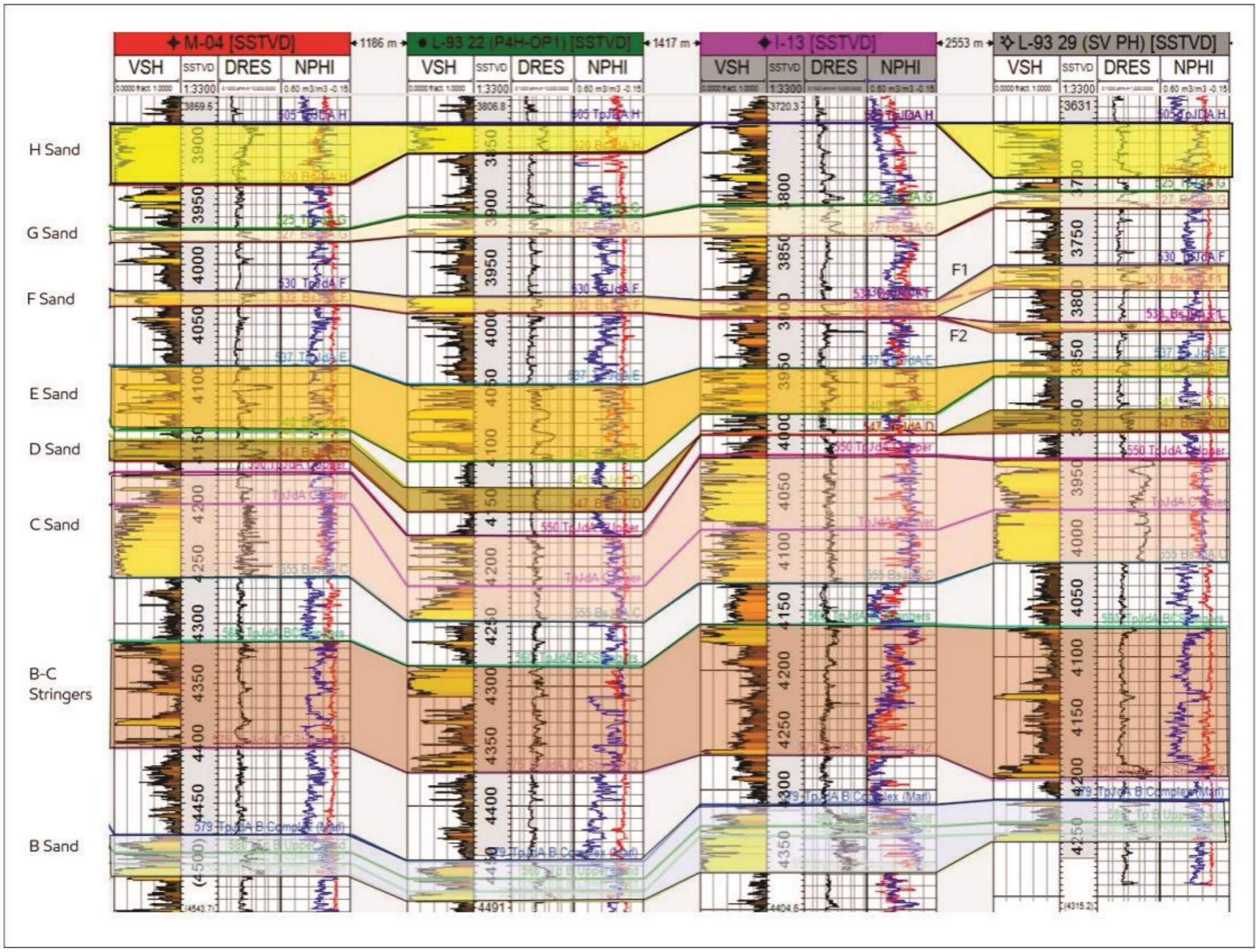

Figure 8: Well cross-section showing stratigraphic correlation between various sands in the JDA Formation wells in the Hebron Horst Block (Source: ExxonMobil Canada Properties, 2022)

The H Sand, the uppermost sand in the JDA Formation, is subdivided into North Valley and South Valley braided fluvial valley depositional systems based on mapped seismic amplitudes. The G, F, E and D sands are interpreted to have been deposited in a sandy braided fluvial complex that includes fluvial channels with reservoir sands deposited in bars, surrounded by fine-grained floodplain and coastal plain deposits. The C Sand, which has been encountered in all Hebron Horst wells drilled to date, is divided into an upper and lower unit with variable sand development. The overall EOD for both upper and lower C Sand is a meandering fluvial channel complex. The B Sand was discussed in the original Hebron Development Plan. It is a sandy braided fluvial complex consisting of amalgamated braided bars and local interfluve islands.

The Proponent constructed maps to illustrate juxtaposition relationships providing a visualization of the potential extent of hydrocarbon accumulations based on cross-fault communication. These relationships form the basis for understanding the extent of hydrocarbon accumulations with the JDA Formation and supports the inclusion of fault blocks surrounding the main Horst Block in the DPA. Hydrocarbon accumulation maps were generated by the Proponent by integrating well, seismic and pressure data to analyze juxtaposition. Fluid contacts for various sands were interpreted, as presented in Table 3.

Table 3: Interpreted fluid contacts for JDA Formation sands. OWC indicates oil-water contact and ODT indicates oil-down-to.

Sand	Contact Type	mTVDss
B Sand	OWC	4520
C Sand	OWC	4028
E/D Sand	OWC	4200
F Sand	ODT	3980
G Sand	ODT	3978
H Sand North Valley	OWC	3912
H Sand South Valley	OWC	3657.5

Staff accepts the Proponent's interpretations of the geologic, seismic and pressure data to interpret reservoir juxtaposition and areal extent of the various hydrocarbon accumulations. This analysis also formed the basis for the designation of seven separate pools at the JDA reservoir level by the CCO in February 2023.

7.1.3. Geophysics

The Proponent's geophysical interpretation was based on the Hebron IsoMetrix survey acquired in 2013 by Schlumberger (WesternGeco) as a new 4D baseline survey for the Hebron Field. It is a multicomponent survey with dense channel spacing resulting in full fold of 60.

The main objective of the Hebron Tilted Transverse Isotropy (TTI) Anisotropic Post Stack Depth Migration (APSDM) processing was to provide a high-resolution image of the Hebron reservoirs with better fault geometry definition and fewer fault sag artifacts. The processing was completed in 2015.

Geologic events interpreted on wireline logs were tied to the seismic using synthetic seismograms from the following wells:

- Hebron M-04;
- Hebron I-13;
- Hebron L-93 29;
- Hebron L-93 22.

The Proponent mapped key seismic horizons with particular attention to the following Jeanne d'Arc horizons: H Sand, G Sand, F Sand, E Sand, D Sand, C Sand, BD sands and the B Sand. Seismic horizon ties to well tops have less than 15% error (<~40-50 m).

Faults were mapped around the Hebron horst and surrounding structural features. This interpretation was used for the fault juxtaposition work done to determine hydrocarbon contacts at faults.

The methods detailed in the Application are considered reasonable and staff have accepted the Proponent's seismic surfaces as the basis for its geologic modelling.

7.1.4. Petrophysics

Comprehensive log and core data sets are available from the earlier drilled exploration wells in the JDA Formation in Hebron Field. The data were supplemented with high quality logging-while-drilling (LWD) and wireline logs acquired by the Proponent in the recently drilled L-93 22 and L-93 29 wells. The Application contains a summary of the key petrophysical parameters for all sands encountered in the JDA Formation in various exploration and delineation wells drilled to date. In addition, the Proponent has described the methodology employed in the selection and use of various petrophysical inputs used in the development of petrophysical models.

Staff reviewed the Petrophysics section of the Application and determined that the data, methodology and assumptions used by the Proponent in the development of the Application are sound and in accordance with established industry practices and procedures. An independent analysis by staff produced very similar results. Hence, the petrophysical interpretation presented by the Proponent in support of the Application is considered reasonable and appropriate.

7.1.5. Reservoir Geologic Modelling

4.1.5.1 Proponent's Geologic Model

When the Hebron Development Plan was submitted in 2011, two delineation wells, Hebron I-13 and Hebron M-04, had penetrated the JDA Formation confirming the presence of hydrocarbons within the H Sand and B Sand reservoirs. Additional sand with hydrocarbon accumulations were recognized but not included.

The Proponent submitted several iterations of a geologic model for the H and B Sands of the JDA Formation in support of the original Hebron Development Plan and the Commercial Discovery Declaration. Based on the results of development drilling of L-93 22, L-93 29 and L-93 30Z, a new multi-sand geological model (JDA Framework for CoVs Aug 2022) for the JDA Formation was created in support of development of the additional sand intervals. This is the most current model supporting the Application and was the basis for the construction of Board staff's static 3D reservoir model of the JDA.

The Proponent's Hebron JDA Framework model was constructed with the objective to incorporate all observations and learnings acquired from seismic interpretation, development drilling and fluid and pressure analysis for all sands encountered in the JDA Formation into a single geological model such that the model can be used for simulation for commingled production, history matching and forecasting. The area of interest for the model encompasses the main fault block (Horst), northeast segment, graben, plus additional blocks to the east and south (Figure 9) to illustrate the Proponent's interpretation of fluid contacts and sand juxtapositions.

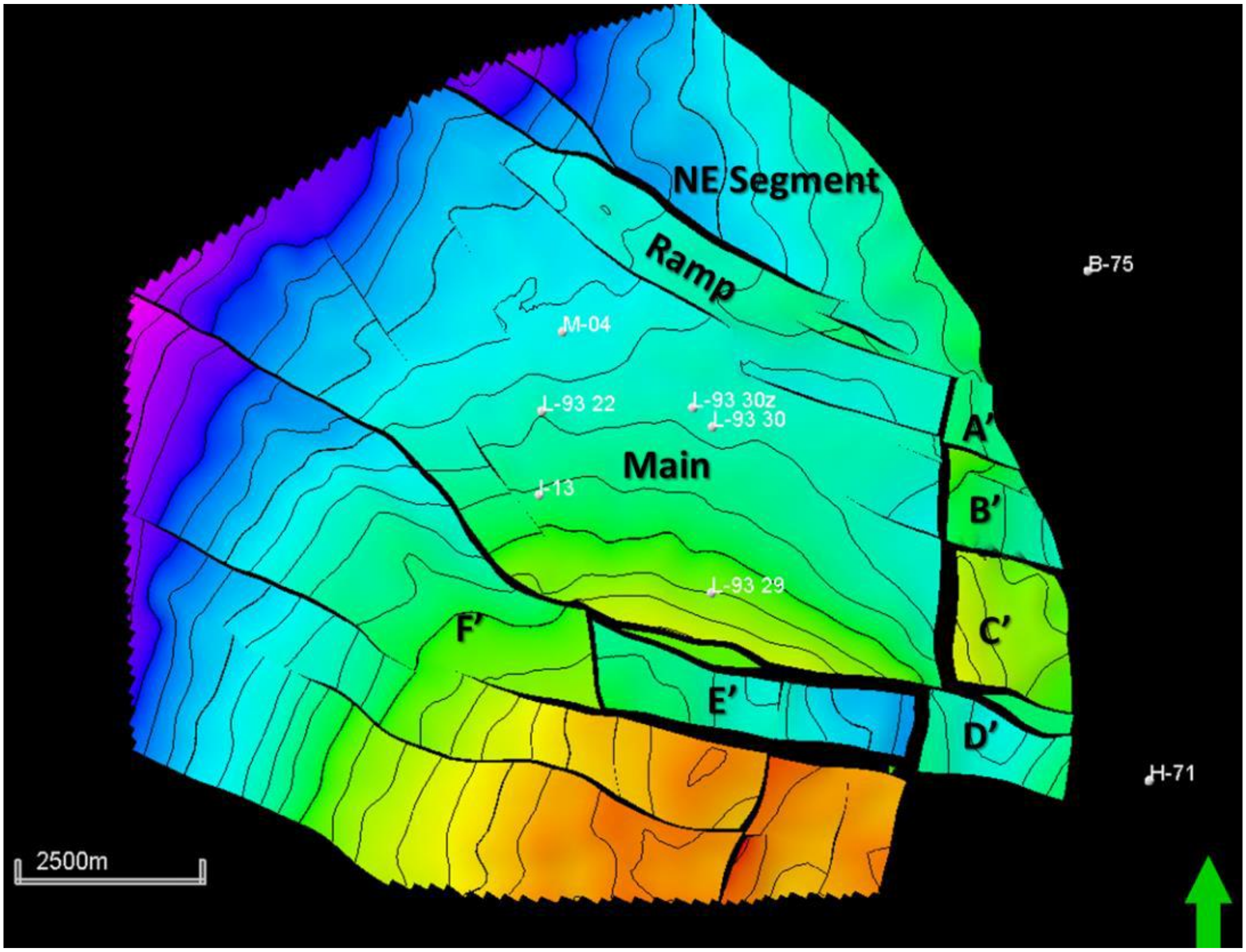

Figure 9: Proponent's area of interest for the JDA Framework geomodel (ExxonMobil, 2022)

The model has two grids: a smooth fault pillar grid and a "zig-zag" fault grid. The smooth fault pillar grid is ideal for visualizations; however, issues may arise during simulation due to the distorting of grid cells around the faults. The "zig-zag" grid, like the smooth fault grid, honours the sand juxtaposition and preserves cell geometry for simulation around the faults. The Proponent used identical workflows for both grids within the model to ensure consistency. The fault framework included all faults that would affect the fluid regions. Some minor faults were excluded, as they would not affect pooling. Horizons were generated directly from seismic interpretation. Areas with a high degree of confidence were interpreted, while in lower confidence areas interpretation trended to higher confidence surfaces. The H, F, C, BC Stringers and B sands were mapped at the top and base of each sand to account for thickness variation. The G and E sands were mapped at the top and isopached to the base to enforce zero-thickness edges. A Lower Hibernia Sand (part of Pool 4F) was added within the Graben area to account for juxtaposition, but was not included in other fault blocks. Additional zones within the sand intervals of the JDA Formation were made by isopaching where seismic horizons were interpreted with low confidence, or to incorporate subseismic zonation interpreted from well data. Environment of Deposition (EOD) maps were generated for each sand using amplitude and thickness data, with the exception of the D Sand, as the D Sand is not always fully resolved on seismic data. Fluid contacts within the model have been expressed as a region property to honour sand juxtaposition across fault blocks. The contacts in the JDA Framework model are consistent with those described in the Application.

Staff determined that the smooth fault pillar grid structural model, the “zig-zag” model components and interpreted seismic horizons of the static reservoir model were reasonable and appropriate. The model built by staff used the smooth fault pillar grid approach.

4.1.5.2 C-NLOPB Geologic Model

The drilling data, petrophysical interpretation and well material obtained through exploration, delineation and development drilling, as well as Proponent interpretations based on the recent 3D seismic data, form the basis of the staff’s model. The model includes well data from recently drilled wells L-93 22, L-93 29 and L-93 30Z, as well as delineation well data from the M-04 and I-13 wells, the latter delineation wells being the only delineation wells to penetrate the JDA Formation in the Hebron Horst block. Drilling data acquired by LWD and wireline for these wells was interpreted by petrophysical staff and incorporated to be used in the model creation.

The structural interpretation from the Proponent’s model was used by staff as the foundation to build and populate an independent reservoir model for the Pool 4 JDA sands using Petrel. For simplicity and ease of comparison, individual sand units and the separating shale units were modelled using the Proponent’s interpreted seismic horizons and staff interpreted well tops as input data. Zonation and layering of the JDA reservoir were interpreted for each sand reservoir with the separating shale units assigned to a single layer.

In developing a model for EOD, staff referred to EOD maps from the Proponent’s model. EOD maps for each sand were digitized and combined through geometric modelling and use of a property calculator to create a full EOD model. Facies logs were created for each well using petrophysical cutoffs for Vshale and porosity. The well logs were then upscaled and used to populate the 3D grid.

Staff’s static geologic model was created by populating the grid with petrophysical properties like porosity, permeability and water saturation. Porosity data available from well logs was imported to Petrel, upscaled and distributed throughout the 3D grid using a sequential Gaussian simulation algorithm and conditioned to the EOD model. Permeability logs were generated for wells using a porosity-permeability transform and then upscaled to the 3D grid. Similarly, water saturation data was calculated for all the wells and then upscaled to the 3D grid. The model was populated using a sequential Gaussian simulation algorithm, and co-krigged to the porosity data. In modelling of the B’, C’ and F’ fault blocks for the C Sand, as well as the E’ fault block for the H Sand, water saturation was recalculated using saturation height functions for each well and distributed throughout the 3D grid.

Staff used similar methods to the Proponent in the construction of the static reservoir model for the JDA reservoirs and population of data in the 3D grid for petrophysical properties. For the modelling of the Lower Hibernia Sand, the Proponent used offset well data and populated the model with average value properties in order to generate a high side estimate of STOOIP. The model submitted by the Proponent is a reasonable representation of the available geological and geophysical data and produced similar results to the staff model.

7.2. Oil and Gas in Place

Staff assessed the in-place hydrocarbon resources in the H, G, F, E, D, C and B sands. In-place hydrocarbon values for each sand of the JDA Formation were calculated using the Petrel static reservoir model. The fluid properties used, including porosity, water saturation, formation volume factor and solution gas-oil ratio were aligned with values used by the Proponent, as described in the submitted simulation model and the Application. These values were used to generate volumes of hydrocarbons in place for each sand in the JDA Formation. In order to develop downside, best estimate and upside values of in-place hydrocarbons, a workflow was created to vary parameters in the calculation to account for uncertainty. Uncertainty was also incorporated into the fluid contacts for the various sands. Using a separate workflow, uncertainty was applied to the fluid contacts and combined with uncertainty of other properties in the volume calculation, and a number of cases were run to develop in-place estimates. Estimates for each sand by fault block were achieved by filtering.

A comparison of the Proponent's and C-NLOPB's volumetric estimates for oil proposed to be exploited from the JDA Formation are shown in Table 4.

Table 4: Comparison of Proponent's and C-NLOPB's estimates of stock-tank original oil in place (STOOIP).

Sand	Fault Block	Units	Downside		Best Estimate		Upside	
			ExxonMobil	C-NLOPB	ExxonMobil	C-NLOPB	ExxonMobil	C-NLOPB
H North Valley	Horst	MMbbl	140.0	133.5	170.0	177.2	245.0	207.4
		MMm^3	22.3	21.2	27.0	28.2	39.0	33.0
H South Valley	Horst A'	MMbbl	3.2	18.7	5.9	29.9	8.9	35.4
		MMm^3	0.5	3.0	0.9	4.8	1.4	5.6
G	Horst A'	MMbbl	38.5	47.5	76.9	62.1	115.4	72.0
		MMm^3	6.1	7.6	12.2	9.9	18.3	11.4
F	Horst A'	MMbbl	29.0	22.5	58.3	29.4	87.5	35.6
		MMm^3	4.6	3.6	9.3	4.7	13.9	5.7
E	Horst A'	MMbbl	28.1	45.7	37.4	51.1	56.1	58.0
		MMm^3	4.5	7.3	5.9	8.1	8.9	9.2
D	Horst A'	MMbbl	5.6	0.8	11.4	1.0	17.1	1.3
		MMm^3	0.9	0.1	1.8	0.2	2.7	0.2
C	Horst A'	MMbbl	46.3	82.5	91.9	94.9	137.9	106.2
		MMm^3	7.4	13.1	14.6	15.1	21.9	16.9
B	Horst A'	MMbbl	83.5	99.8	111.4	113.5	167.0	127.6
		MMm^3	13.3	15.9	17.7	18.1	26.6	20.3
C	B'	MMbbl	-	8.9	-	9.6	7.8	10.9
		MMm^3	-	1.4	-	1.5	1.2	1.7
C	C'	MMbbl	-	64.8	-	71.0	61.7	81.9
		MMm^3	-	10.3	-	11.3	9.8	13.0
C	E'	MMbbl	-	3.6	-	4.7	12.8	5.7
		MMm^3	-	0.6	-	0.8	2.0	0.9
C	F'	MMbbl	-	23.8	-	25.5	18.9	29.4
		MMm^3	-	3.8	-	4.1	3.0	4.7
H	E'	MMbbl	-	38.4	-	41.1	11.2	46.4
		MMm^3	-	6.1	-	6.5	1.8	7.4
Lower Hibernia	E'	MMbbl	-	169.0	-	169.0	169.0	169.0
		MMm^3	-	26.9	-	26.9	26.9	26.9
Total		MMbbl	374.2	759.4	563.2	880.2	1116.3	986.7
		MMm^3	59.6	120.8	89.4	140.0	177.4	156.9

The following section provides commentary on individual sands and describes where there are notable discrepancies between the Proponent's and the C-NLOPB's interpreted in-place volumes.

H Sand

Overall, there is good agreement between the Proponent and the C-NLOPB's volumetric assessment for STOOIP in the H Sand. Differences between the Proponent and C-NLOPB's STOOIP estimates can be attributed to variations in reservoir modelling approaches, petrophysical analyses and parameters varied in the uncertainty analysis. Staff find that the Proponent's modelling approach and resulting STOOIP volumes are reasonable. The Proponent recently adjusted the low side estimate in the addendum document based on analysis of production data. Future drilling and production data will allow better understanding of reservoir quality and hydrocarbon volume connectivity which will lead to refinement of the models as development progresses.

B Sand

There is also good agreement between the Proponent's and the C-NLOPB's volumetric assessment for STOOIP in the B Sand. Differences between the Proponent and C-NLOPB's STOOIP estimates are attributed to variations in reservoir modelling approaches, petrophysical analyses and parameters varied in the uncertainty analysis. The C-NLOPB's estimate for STOOIP is in agreement with those of the Proponent.

G Sand

There is relatively good agreement between the Proponent's and C-NLOPB's STOOIP estimates for the G Sand. Staff estimates are slightly lower than the Proponent's due to differences in modelling approach, petrophysical analyses and uncertainty applied to parameters for volumetric calculations.

F Sand

Staff estimates of STOOIP values for the F Sand are lower than those of the Proponent. Differences can be attributed to differences in modelling approach, petrophysical analyses and interpretation of and uncertainty applied to parameters for volumetric calculations.

D Sand

There is not good agreement between the Proponent's and staff's STOOIP estimates for the D Sand. Differences can be attributed to differences in modelling approach, petrophysical analyses and uncertainty applied to parameters for volumetric calculations.

E Sand

There is relatively good agreement between the Proponent's and staff's STOOIP estimates for the E Sand. Differences can be attributed to differences in modelling approach, petrophysical analyses and uncertainty applied to parameters for volumetric calculations.

C Sand

There is relatively good agreement between the Proponent's and staff's STOOIP estimates for the C Sand. Any differences can be attributed to differing approaches to geological modelling, combined with differences in petrophysical analyses.

Estimates for solution gas initially in place were provided in the Application (Table 5). The C-NLOPB estimates were calculated using C-NLOPB's STOOIP estimates and the fluid properties for each sand.

Table 5: Comparison of Proponent's and C-NLOPB's estimates of solution gas in place in the JDA Formation.

Sand	Fault Block	Units	Downside		Best Estimate		Upside	
			ExxonMobil	C-NLOPB	ExxonMobil	C-NLOPB	ExxonMobil	C-NLOPB
H North Valley	Horst	GCF	81.6	77.6	99.4	103.0	142.0	120.5
		Gm^3	2.3	2.2	2.8	2.9	4.0*	3.4
H South Valley	Horst A'	GCF	3.5	10.9	3.5	17.4	7.1	20.6
		Gm^3	0.1	0.3	0.1	0.5	0.2	0.6
G	Horst A'	GCF	28.4	31.9	53.2	41.7	81.6	48.3
		Gm^3	0.8	0.9	1.5	1.2	2.3	1.4
F	Horst A'	GCF	21.3	16.0	39.0	21.0	60.3	25.4
		Gm^3	0.6	0.5	1.1	0.6	1.7	0.7
E	Horst A'	GCF	63.9	106.5	85.2	119.3	127.8	135.3
		Gm^3	1.8	3.0	2.4	3.4	3.6	3.8
D	Horst A'	GCF	14.2	1.3	24.8	1.6	39.0	2.1
		Gm^3	0.4	0.0	0.7	0.0	1.1	0.1
C	Horst A'	GCF	78.1	136.9	152.6	157.6	227.2	176.3
		Gm^3	2.2	3.9	4.3	4.4	6.4	5.0
B	Horst A'	GCF	149.1	177.9	198.8	202.7	298.1	227.3
		Gm^3	4.2	5.0	5.6	5.7	8.4	6.4
C	B'	GCF	-	8.3	-	9.1	7.1	10.2
		Gm^3	-	0.2	-	0.3	0.2	0.3
C	C'	GCF	-	44.8	-	49.1	42.6	56.6
		Gm^3	-	1.3	-	1.4	1.2	1.6
C	E'	GCF	-	6.1	-	8.0	21.3	9.7
		Gm^3	-	0.2	-	0.2	0.6	0.3
C	F'	GCF	-	40.2	-	43.2	31.9	49.8
		Gm^3	-	1.1	-	1.2	0.9	1.4
H	E'	GCF	-	60.2	-	64.5	17.7	72.7
		Gm^3	-	1.7	-	1.8	0.5	2.0
Lower Hibernia	E'	GCF	-	117.1	-	117.1	117.1	117.1
		Gm^3	-	3.3	-	3.3	3.3	3.3
Total		GCF	440.1	835.8	656.6	955.1	1221.0	1071.9
		Gm^3	12.4	23.5	18.5	26.9	34.4	30.2

*H North Valley Upside in the Addendum was 3.3 Gm^3. Proponent confirmed through subsequent communication that this was an error and the value should be 4.0 Gm^3, consistent with the original submission.

7.3. Reservoir Engineering

Analysis of the reservoir engineering component of the Application included a review of the following items:

- Reservoir pressures and free water levels (FWLs);
- Reservoir temperature;
- Fluid characterization;
- Special core analysis (SCAL);
- Drill stem tests.

7.3.1. Reservoir Pressure and Free Water Levels

Pressure data gathered from wireline and drill stem test (DST) operations are plotted in Figure 10. High-level observations from the plot show that the Hebron reservoirs (data from the M-04, D-94 and I-13 wells) are generally normally pressured although some minor over-pressuring exists in some of the JDA Formation in the M-04 and I-13 wells.

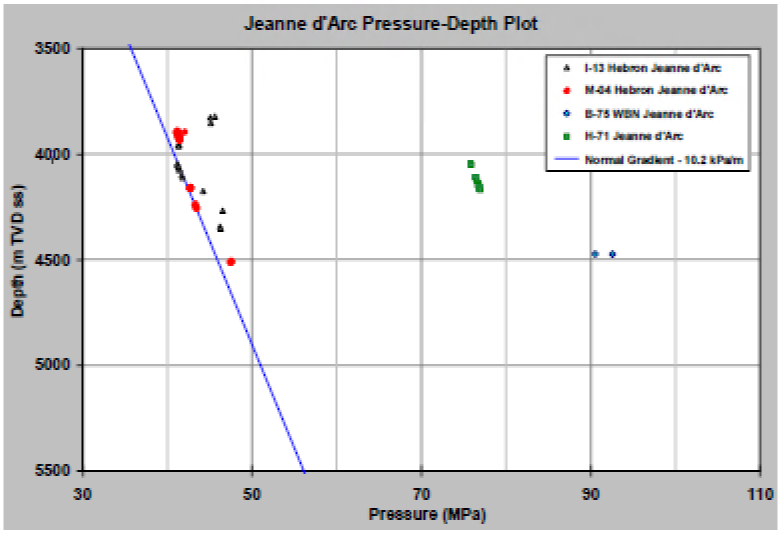

Figure 10: Hebron Jeanne d'Arc Formation pressure depth plot (Source: ExxonMobil Canada Properties, 2022)

Pressure measurements recorded for the JDA Formation in the Hebron Field are plotted against depth in Figure 11. The plot includes data from the exploration wells (I-13 and M-04) as well as the development wells drilled to date (L-93 22, L-93 29 and L-93 30Z). The data indicates that the JDA Formation is normally pressured to slightly overpressured in the Hebron Field. Consistent with observations in other pools, there are some minor pressure differences depending on the vintage of the data collection. These differences are interpreted to be a result of gauge uncertainty due to differences in gauge type/vintage, hole size and time after bit.

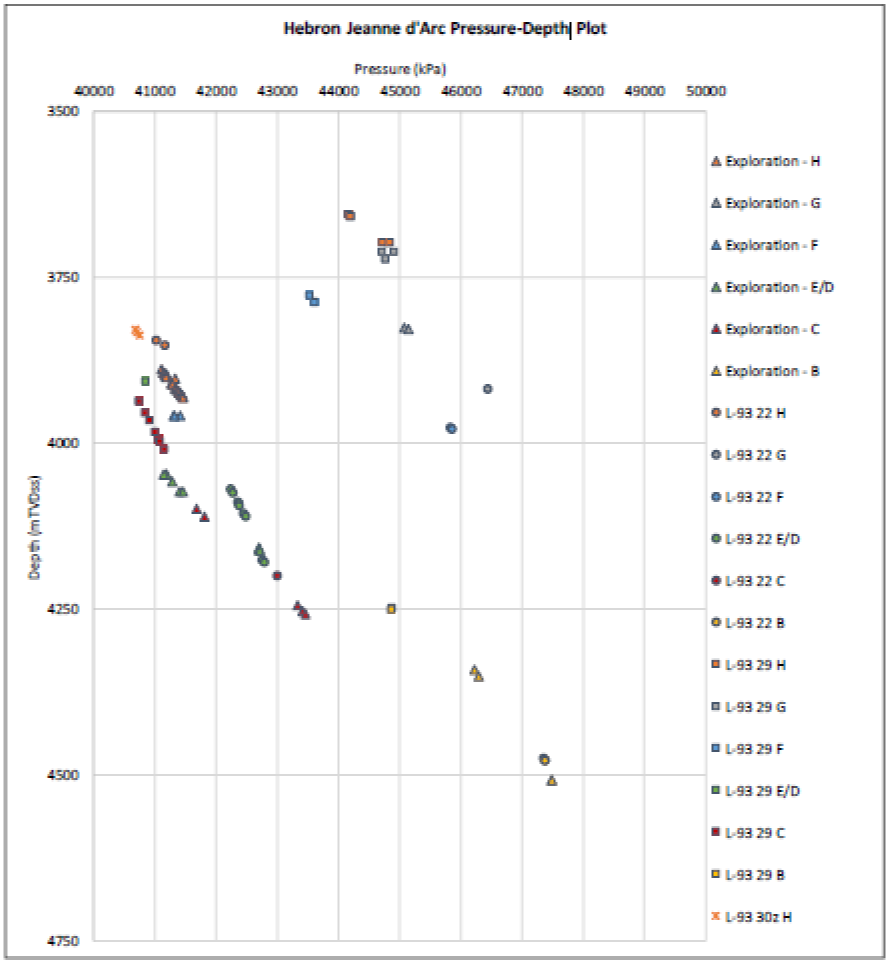

Figure 11: Hebron Jeanne d'Arc Formation pressure depth plot (Source: ExxonMobil Canada Properties, 2022)

The log, core, fluid and pressure data acquired for each sand were used to determine a most likely FWL for each sand. There is evidence of perched water and the extent of these contacts throughout the reservoir remains uncertain. The base case assumptions for initial pressure, pressure gradients and FWL are listed in Table 6. A comparison of the initial pressure line to the data gathered to date is shown by sand in Figure 12 and additional detail is included in the subsequent subsections.

Table 6: Jeanne d'Arc Formation initial pressure and free water levels by sand (Source: ExxonMobil Canada Properties, 2022)

	Initial Pressure kPa	Reference Depth mTVDss	Oil Gradient kPa/m	Water Gradient kPa/m	Free Water Level mTVDss
H Sand NV	41175	3900	7.5	10.2	3912
H Sand SV	44168	3658	7.5	10.2	3660
G Sand	44168	3658	7.32	10.2	3986
F Sand	44485	3822	7.32	10.2	3986
E/D Sand	42349	4089	5.64	10.2	4200
C Sand	40837	3955	5.93	10.2	4028
B Sand	47356	4476	5.96	10.2	4520

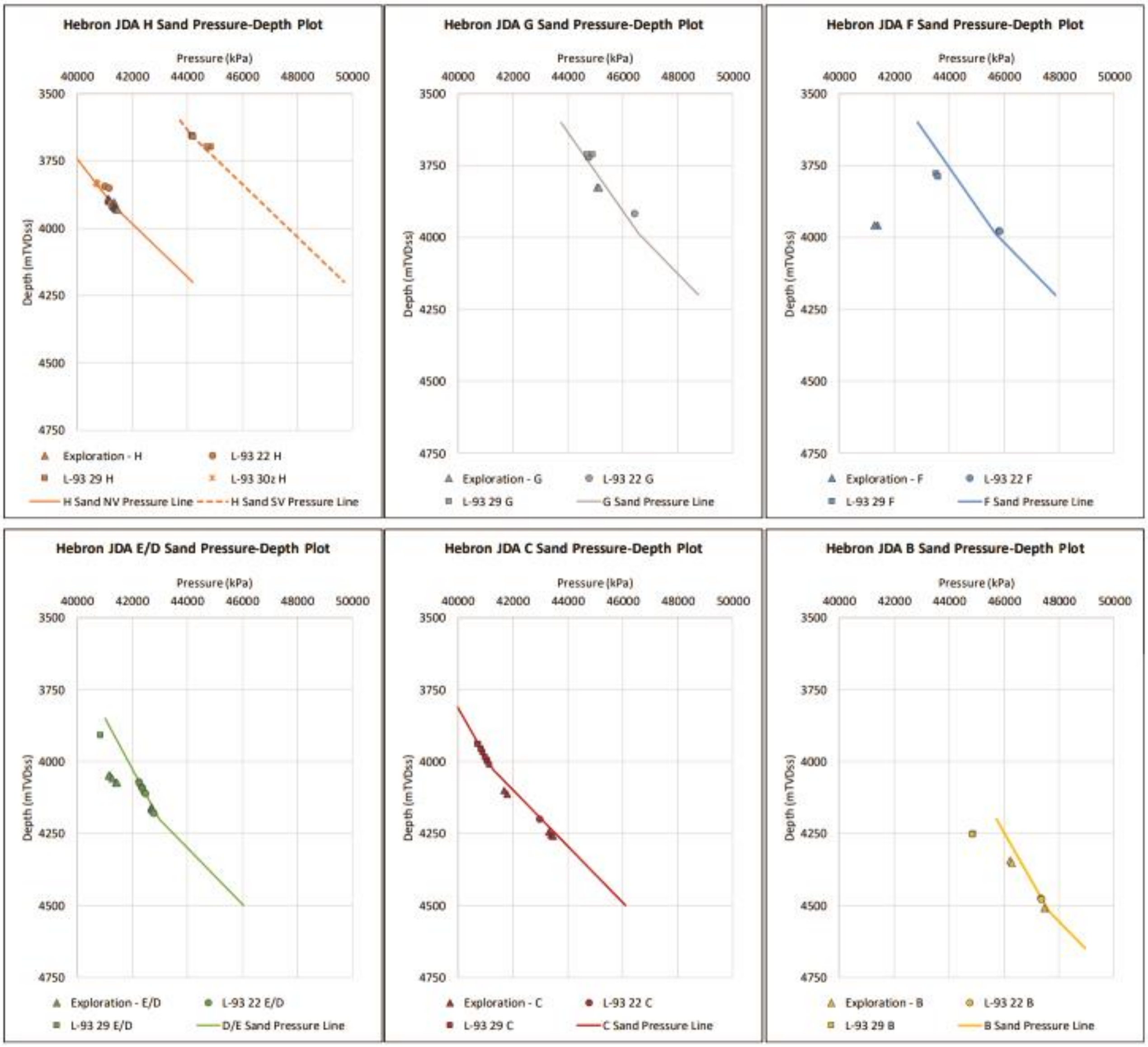

Figure 12: Jeanne d'Arc Formation pressure-depth plot by sand (Source: ExxonMobil Canada Properties, 2022)

4.4.1.1 H Sand Pressure and FWL

The H Sand data acquired in L-93 22 and M-04 are from North Valley. The water is pressured up relative to hydrostatic and the 3912 mTVDss OWC is interpreted to be perched. The H Sand encountered in L-93 29 was thin and an OWC was encountered in the well at 3657.5 mTVDss. The pressure data acquired in the oil leg are elevated with respect to projections from North Valley and indicate the North and South valleys of the H Sand are not connected and constitute separate oil accumulations. A FWL of 3660 mTVDss is based on the observed water saturation and the saturation-height function.

4.4.1.2 G Sand Pressure and FWL

Pressure data for the G Sand were acquired in L-93 29 and L-93 22, in addition to repeat formation tester pressure data from I-13. The G Sand is overpressured and inconsistent measurements were recorded within the lobes of the G Sand at L-93 22. No obvious flaw was identified with the data and it is possible that the G Sand includes several poorly connected sand bodies with perched water contacts. No contact has been identified for the G Sand, as the sand has been oil filled in all wells. G Sand oil–down-to (ODT) is 3978 mTVDss. A FWL of 3986 mTVDss, consistent with F Sand, was assumed based on the similarity of the ODT depth.

4.4.1.3 F Sand Pressure and FWL

The F Sand is usually thin with variable sand development. Pressure points are only available in L-93 22 and L-93 29 with scatter data from L-93 29. Of the three pressure points collected in L-93 29, only one point appears to be close to an oil gradient established with L-93 22. The remaining two points sit off the gradient at lower pressure. This may indicate limited lateral extent of individual sand bodies within the F Sand and potential for smaller sand bodies to be isolated. F Sand ODT is 3980 mTVDss based on L-93 22, as F Sand was not developed in M-04. An interpreted FWL of 3986 mTVDss is based on the observed water saturation and the saturation height function.

4.4.1.4 E/D Sands Pressure and FWL

The E and D sands are interpreted to be on the same oil gradient and share the same OWC. E Sand oil pressure data collected in L-93 22 is consistent with the oil pressure collected in the D Sand in M-04 once differences in time after bit are accounted for in the data collection. The interpreted FWL for the E/D sand is 4200 mTVDss based on the intersection of the oil pressure line with the hydrostatic water line. The E and D sands are vertically close together and the E Sand is interpreted to cut into the D Sand via channel-base erosion.

The D Sand pressure point from L-93 29 appears depleted with respect to the E/D sand original pressure. Given the production in the E Sand at L-93 22, the D Sand is interpreted to be connected to the main E/D sand complex and is depleted due to production.

4.4.1.4 C Sand Pressure and FWL

Prior to L-93 29, all wells penetrating the C Sand were wet. Aquifer pressure data from L-93 22 is consistent with a hydrostatic water line. L-93 29 confirmed oil on rock with an interpreted FWL of 4028 mTVDss.

4.4.1.5 B Sand Pressure and FWL

The B Sand aquifer has not been penetrated by any of the wells drilled to date; however, mapping of the interval and an analysis of the seismic amplitude is interpreted to delineate the stratigraphic edge of the B Sand below the M-04 well. The interpreted FWL is 4520 mTVDss based on the observed water saturation and the saturation height function.

A single oil pressure point was collected in L-93 29 and is interpreted to be depleted based on production in L-93 22. The magnitude of the depletion is consistent with a limited connection to the producing well and this was used as a history-matching parameter for the simulation model. It should be noted that the test was considered to be of medium quality but appears to be valid.

Staff reviewed the Proponent’s interpretation of reservoir pressure data presented in the Application and the interpretation is considered reasonable and appropriate.

7.3.2. Reservoir Temperature

Reservoir temperature information was gathered during drilling and production testing operations. A limited number of data points are available from the exploration DST program from the I-13, M-04 and B-75 wells. In addition, L-93 22, the first JDA Formation development well, included temperature gauges in four of the sands through use of intelligent well completion (IWC) technology. There is good alignment between both datasets. Staff reviewed the Proponent's interpretation that the best-fit regression indicates a temperature gradient of 2.6°C/100 m and consider the temperature data presented to be reasonable. The temperature profile for the JDA Formation is shown in Figure 13.

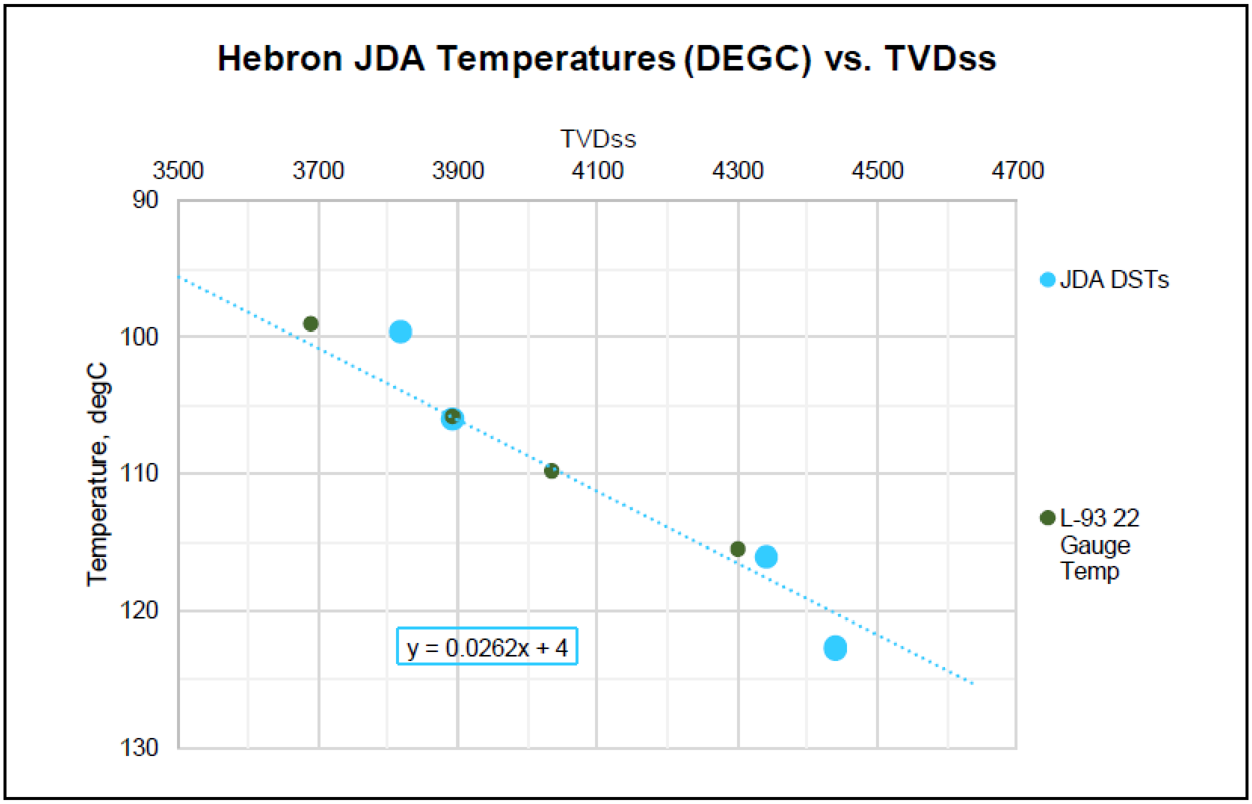

Figure 13: JDA Formation temperatures-depth plot (Source: ExxonMobil Canada Properties, 2022)

Staff reviewed the Proponent's interpretation of reservoir temperature data presented in the Application. The interpretation is considered reasonable and appropriate.

7.3.3. Fluid Characterization

Multiple bottom hole and separator fluid samples were acquired from several productive intervals of the wells drilled across the JDA Formation. There is a higher degree of uncertainty with the results from the exploration wells, particularly those based on surface samples, due to uncertainty in the metering. All samples have been included for reference, but the development wells are assumed to be of higher confidence. The samples have been used to define the fluid properties of the various reservoir intervals. Table 7 provides a high-level summary of the fluid sampling conducted. In general, the fluid properties for the shallower sands (H, G and F) are slightly heavier than the fluids in the deeper sands (E/D, C and B).

Table 7: Summary of JDA Formation oil fluid properties by well and sand (Source: ExxonMobil Canada Properties, 2022)

Well	DST or Sample #	Field	Formation	Interval/ Depth (m TVDSS)	Res Pres (MPa)	Res Temp (°C)	Sat. Pressure (MPa)	Oil Visc @ Psat (cp)	Oil Gravity °API	Oil FVF @ Pres (rm3/Sm3)	GOR Sep Test (m3/m3)	Oil Compressibility (1/kPa)
I-13	5	Hebron	JdA G Sand	3815 – 3830	45.8	99	22.2	1	31.7	1.37	119	--
I-13	1	Hebron	JdA B Sand	4340 – 4354	47.5	117	30	0.2	39.8	1.55	198	--
M-04	0907-EA	Hebron	JdA H Sand	3842	41.1	106	24.9	1.51	25.6	1.3	98	1.20E-06
M-04	3421-MA	Hebron	JdA D Sand	4183	42.7	116	37	0.21	37.8	1.818	276	2.90E-06
M-04	3385-MA	Hebron	JdA B Sand	4533	47.5	125	35	0.21	38	1.731	261	2.60E-06
B-75	5	W. Ben Nevis	JdA F Sand	4473 – 4482	91.4	121	29	0.5	37	1.414	178	--
L-93 22	03519	Hebron	JdA E Sand	4065-4114	42.1	113	40.8	0.214	35.7	2.203	413.3	4.00E-06
L-93 22	03520	Hebron	JdA B Sand	4455-4483	47.5	125	34.6	0.219	35.8	2.046	327.9	3.20E-06
L-93 29	00207-1	Hebron	JdA F Sand	3870	43.7	113	24.5	0.786	29.6	1.387	126.6	1.50E-06
L-93 29	00207-2	Hebron	JdA C Sand	4020	40.8	109.6	34.3	0.235	38	1.905	294.2	3.10E-06
L-93 29	00207-3	Hebron	JdA B Sand	4333	45.0	118.3	35.3	0.236	37.1	1.905	291.1	3.20E-06

Compositional data by sand acquired from L-93 22 and L-93 29 are included in Table 8. These fluid samples are deemed to be of highest confidence and they provide a good representation of the changes in fluid properties across the JDA Formation sands.

Table 8: Summary of JDA Formation compositional data (Source: ExxonMobil Canada Properties, 2022)

Sand	F	E	C	B	B
Well Sample type	L-93 29 BH (Uncont-aminated)	L-93 22 Surf. Recombined	L-93 29 BH (Uncont-aminated)	L-93 29 BH (Uncont-aminated)	L-93 22 Surf. Recombined
Hydrogen	0.00	0.00	0.00	0.00	0.00
Hydrogen Sulphide	0.00	0.00	0.00	0.00	0.00
Carbon Dioxide	0.68	1.29	1.22	1.80	1.77
Nitrogen	0.19	0.15	0.23	0.23	0.17
Methane	47.02	62.43	59.68	57.49	56.21
Ethane	4.65	6.61	6.70	7.29	7.42
Propane	4.23	4.89	5.31	4.65	5.48
i-Butane	0.89	0.82	0.80	0.78	0.92
n-Butane	2.37	2.13	2.21	2.20	2.53
neo-Pentane	0.01	0.01	0.01	0.01	0.01
i-Pentane	1.08	0.74	0.86	0.87	0.98
n-Pentane	1.52	1.09	1.28	1.30	1.40
Hexanes	2.20	1.42	1.73	1.77	1.88
C7+	35.17	18.43	19.99	21.61	21.23
C7+ Molecular Weight (g mol-1)	276.7	220.8	224.7	227.6	219.0
C7+ Density at 15.0°C (g cm-3)	0.8915	0.8495	0.8473	0.8527	0.8498

No formation water samples were acquired from the JDA Formation in the exploration wells. A downhole water sample was acquired from L-93 29 in the H Sand South Valley. In addition, a produced water sample was acquired from L-93 30Z in the H Sand North Valley. Both water samples may be perched and might not be representative of the water in the entirety of the JDA Formation. Properties of the samples are shown in Table 9 and compared to the regional water data acquired from the Ben Nevis and Hibernia formations.

Table 9: Summary of Hebron Field water properties (Source: ExxonMobil Canada Properties, 2022)

	Units	M-04 Well, Ben Nevis Sample # 2.09	M-04 Well, Hibernia Sample # 1.07	L-93 29 (SV PH) JdA (H Sand) 202200207-3	L-93 30z JdA (H Sand) TW081752
Sodium, Na	mg/l	21789	32297	43410	24900
Potassium, K	mg/l	255	317	160	1900
Calcium, Ca	mg/l	1541	1990	2780	1000
Magnesium, Mg	mg/l	413	283	320	112
Strontium, Sr	mg/l	234	303	195	71.6
Barium, Ba	mg/l	22.3	3.62	0.63	3.26
Iron, Fe	mg/l	11.2	4.13	20	2.38
Manganese, Mn	mg/l	0.127	0.496	300	6.17
Lithium, Li	mg/l	3.39	5.65	7.2	3.43
Aluminum, Al	mg/l	0.062	0.42	0	0.63
Silicon, Si	mg/l	59.8	102	30	28.5
Boron, B	mg/l	92.7	186.3	61	66.6
Iodine, I	mg/l	122.4	276.8	130	0
Phosphorus, P	mg/l	8	17.5	0.17	<0.20
Zinc, Zn	mg/l	0.053	1.231	1.6	0.16
Chloride, Cl	mg/l	34925	48528	69690	41900
Sulphate, SO_4	mg/l	0	99	950	1100
Bromide, Br	mg/l	101	134	260	170
Alkalinity	mg/l	570	560	815	270
pH @ 25°C	-	7.71	7.66	7.32	7.7
TDS	mg/l	60273	85632	119562	71500
Density @ 25° C	g/cc	1.037	1.0525	1.0802	1.0515

Staff agree that the updates to the reservoir fluid characterizations made by the Proponent are reasonable and appropriate.

7.3.4. Special Core Analysis (SCAL)

Early SCAL data for the JDA Formation in the I-13 exploration well has reliability issues and was not used in this assessment. A SCAL study is currently underway for the JDA Formation H Sand using core acquired from L-93 22. Preliminary results from the SCAL program were used to calibrate the correction for permeability to oil to be used in the simulation model.

The original saturation height functions used for the JDA Formation were sand specific (H and B sands) and based on matching to log (Archie) water saturation. In 2021, the H Sand function was updated to incorporate the results from L-93 22. In 2022, the saturation height function for the B Sand was revisited to incorporate the results from L-93 22 and L-93 29. Emphasis was placed on matching to the newer vintage logs. The saturation height function is converted to capillary pressure tables for use in the simulation model. The conversion is based on difference in density between the two fluids, oil and water. Preliminary results from the L-93 22 H Sand Air-Brine capillary pressure tests were subsequently received and these enabled a blind test of the unified saturation height function. Eight core plugs were tested and the resultant capillary pressure was compared to the predicted values based on the saturation height function. The saturation height model will continue to be refined as needed.

The 2022 JDA Formation simulation model is set up with capillary pressure tables generated from the unified saturation height function. Using a common set of capillary pressure tables for the simulation model greatly simplifies the setup of the cases and minimizes the number of displacement tables required. A minor discrepancy is introduced due to the differences in oil density between the shallower (H/G/F) sands and the deeper (E/D, C, B) sands. The tables are set up based on the density of the deeper oil, which results in a slight over prediction of water saturation in the transition zone of the shallower sands. The JDA Formation water-oil primary drainage capillary pressure curves are presented in the Application and these were used by the Proponent in its reservoir simulation model.

Corey type-equations were used to define the relative permeability inputs for the JDA reservoir studies. No reliable relative permeability data was available from the exploration wells. Preliminary results have been received from one of the L-93 22 steady state composites. There is reasonable alignment between the Corey exponents currently in use and the L-93 22 composite 1 results, and the results are consistent with analogue data for intermediate-wettability displacement behaviour. As the remainder of the SCAL results are received for L-93 22, the Corey equations will be optimized to provide a best fit. Water-oil imbibition capillary pressure data is not yet available to validate the residual oil saturation. The Sorw value of 0.15 is based on analogue data and aligns well with the preliminary steady-state relative permeability data. The model is binned by permeability ranges to account for variation in the capillary pressure curves. The same Corey exponents and Sorw are used for each of the bins with a changing Swirr value based on the permeability.

Staff consider the Proponent’s approach of incorporating SCAL data to be acceptable.

7.3.5. Drill Stem Tests

The M-04 and I-13 wells were drilled into the JDA Formation and DSTs were conducted within the B and G sands in I-13 and in the H Sand in M-04. The data obtained from the earlier wells, including I-13, was not as reliable as the data from the more recent well tests. Some of the issues observed with the early well DSTs included:

- poor resolution or accuracy of the mechanical pressure gauges in use at the time,
- inefficient monitoring of rate data, especially during the clean-up period, and
- poor accuracy in the flow data especially for low flow rate situations.

A summary of the results from the DST analysis are shown in Table 10.

Table 10: Summary of Hebron JDA DST tests (Source: ExxonMobil Canada Properties, 2022)

Well	DST #	Field	Formation	Interval (mRT)	Fluid Type	Max Oil Flow Rate (m3/d)	Oil Gravity (oAPI)	Pay (m)	Est kh (m*md)	Est Perm (md)	Skin Factor	Radius of Invest. (m)	Boundaries
I-13	1	Hebron	JdA B	4368 – 4381	Oil	592	36.1	13	776	60	20	310	Yes
I-13	5	Hebron	JdA G	3842 – 3857	Oil	857	31.4	15	2040	136	12.4	420	Not Likely
M-04	1	Hebron	JdA H	3906 – 3924	Oil	340	25.4	18	1223	68	2.35	310	Yes

7.4. Production Results

The first JDA Formation development well was brought online in 2021. L-93 22 was drilled with the primary objective of developing the H Sand. The well was deepened to delineate other potential oil-bearing sands and to determine potential of future commingled production. The well was drilled through to the base of the JDA Formation and completed with an IWC for an extended flow test on the additional sands. Four separate zones were completed in the H, G, E and B sands – each with surface-controlled inflow control valves (ICVs) with dedicated pressure and temperature gauges. The G and E sands were not included in the Hebron Development Plan (Decision Report 2012.01) so their production was approved for a period of one year through the Hebron Project Pool 4 Extended Formation Flow Test. A summary of the production by zone is shown in Figure 14.

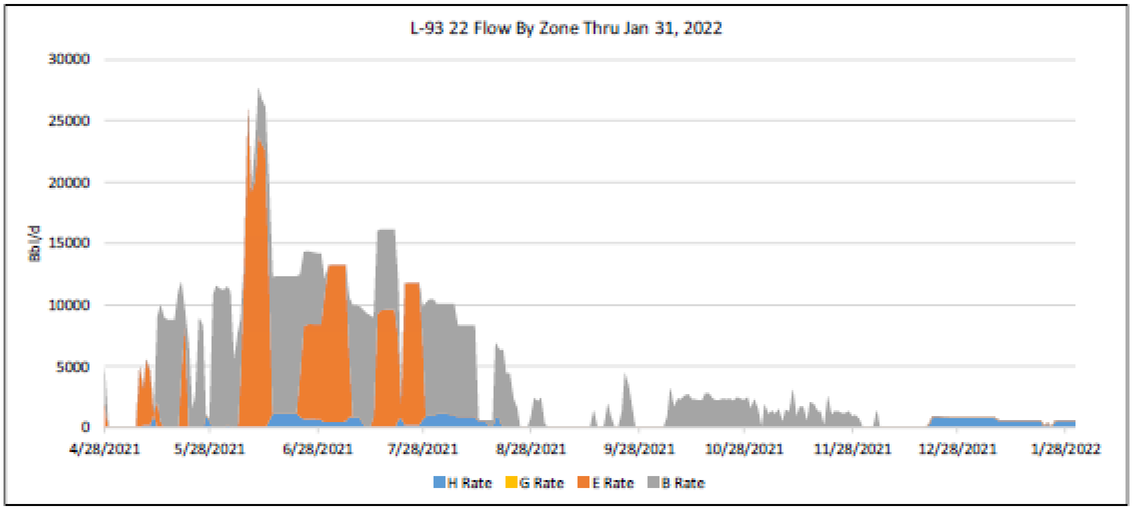

Figure 14: L-93 22 extended flow test production by zone (Source: ExxonMobil Canada Properties, 2022)

7.4.1. H Sand Performance

L-93 22 H Sand dynamic performance indicated lower productivity than predrill expectations with a productivity index (PI) of 0.007 m^3/d/kPa and initial rate of ~1 kbd. The reduced productivity was in part due to lower permeability, which was measured in the core acquired from the L-93 22 well. In addition, the pressure transient analysis (PTA) indicated two boundaries in close proximity to the well. The material balance analysis (MBAL) indicated a very low connected volume, consistent with the PTA observations.

The L-93 22 well was drilled near the edge of the valley axis. The location of the well is interpreted to be one of the key drivers for the poor performance. In addition, it highlighted the importance for future producers to be horizontal to increase the chance of connectivity. The learnings from L-93 22 were incorporated into the design of the first horizontal producer.

L-93 30Z was drilled in the second half of 2022. Early dynamic well learnings were not incorporated into the initial Hebron JDA DPA submission, as data collection and assessment were ongoing at the time of submission. The addendum documented learnings from the L-93 30Z production performance. L-93 30Z was drilled across the axis of the H Sand valley system and encountered good quality sand that exceeded predrill expectations. The initial dynamic performance of L-93 30Z was in line with predrill expectations with a productivity index of 0.4 m^3/d/kPa and an initial rate of 15 kbd (2385 m^3/d).

However, pressure transient analysis on L-93 30Z dynamic data indicated the potential for boundaries or baffles surrounding the well creating uncertainty in the connectivity of the H Sand.

Based on L-93 30Z dynamic results, data collection for the H Sand is a priority and the Proponent has deferred the drilling of dedicated H Sand wells that were initially proposed to be drilled early on the drill schedule.

7.4.2. G Sand Performance

The I-13 exploration well drill stem test showed promising productivity for the G Sand interval; however, during the L-93 22 extended flow test the Proponent was unable to get the G Sand to flow. High drawdown was applied in an attempt to flow the well but no production could be achieved. It is unknown at this time if the failure to flow was due to a reservoir issue or a mechanical wellbore issue. An attempt was made to inject acid into the interval to determine if that would help clean up the perforations, but there was no injectivity into the zone. Potential well work remediation options will continue to be investigated.

7.4.3. E/D Sand Performance

A high quality E Sand interval was observed in L-93 22 with three separate sand intervals. Pressure data indicated the E and D sands are in pressure communication and form a single E/D accumulation with an OWC of ~4200 mTVDss. The E Sand productivity was very high with a PI of ~0.7 m^3/d/kPa and peak rate of 28 kbd. There was good alignment with observations from simulation modelling and analytical models (PTA & MBAL). All models consistently showed a volume of well-connected oil of ~26 MMbbl with a total E/D OOIP of ~40 MMbbl. The area of well-connected oil could be distinguished with the seismic interpretation, which will help with future well placement. The fluid properties were lighter than expectations based on the D Sand exploration well sample. The bubble point pressure was measured to be 40.7 MPa, which is only 1.3 MPa below the original pressure. By the time the new analysis was available, the pressure had reduced to 39.5 MPa. There was no indication of evolved gas within the reservoir. The zone has remained essentially shut in since the pressure was discovered to be below bubble point in order to allow the pressure to build back up.

7.4.4. B Sand Performance

The B Sand reservoir performance from L-93 22 has aligned well with expectations. The well productivity was reasonable with a PI of 0.07 m^3/d/kPa and a peak rate of 12 kbd. The measured fluid properties aligned well with the exploration dataset. A key observation from the PTA was that the best-fit permeability thickness of 600 mD-m was only about 10% of the log-derived value. This observation is consistent with the expectation of heterogeneity within the B Sand, primarily driven by cements.

Issues were encountered with the B Sand ICV several months after the well was brought online. An increase in differential pressure across the B Sand ICV was observed. Following this event, the B Sand ICV was unable to be moved via the surface control system. The well was shut in and troubleshooting of both the B Sand differential pressure increase and the ICV ensued. Intermittent production from the well was possible, but the differential pressure increase across the B Sand ICV was continuing to limit steady production. Wireline intervention was used in late 2021 to shift the B Sand ICV to the closed position. ICV functionality remained for the H, G and E sands. The B Sand ICV was left in the closed position to allow for production from the H Sand. In October 2022, the B Sand ICV was manually opened and the sand was brought back online. With the B Sand ICV fully open, the pressure drop issue was no longer observed, and the zone capacity and ability to flow steady state was returned. ICV functionality and B Sand ICV pressure drop will continue to be monitored.

7.5. Development Strategy

The Hebron Development Plan (Decision Report 2012.01) base case depletion strategy for the JDA Formation H Sand consisted of three highly deviated or horizontal oil producers and a single water injector. The base case depletion plan for the B Sand in that document included a single producer and water injector well pair.

Data from the initial JDA Formation development wells have allowed for sufficient learning to now include the remaining sands of the JDA Formation. The proposed DPA base case depletion plan from the Application, including the changes made in the addendum, includes a total of 17 development wells (12 producers and five water injectors), of which nine wells (seven producers and two water injectors) are newly proposed in this DPA for the remaining sands (Table 11).

Table 11: JDA Formation well count

Sand	Development Plan (Decision Report 2012.01)		Development Plan Amendment (Addendum) (2022)		
	Producers	Injectors	Producers	Injectors	Commingled Potential
H Sand	3	1	**3**	**2**	**1 WI with B Sand**
B Sand	1	1	**2**	**1**	**1 WI with E Sand** **1 WI & 1 OP with C Sand**
E Sand			**1**	**1**	
C Sand			**2**	**1**	
Commingled*			**2**		
“Prime” Blocks			**2**		

*Commingled includes L-93 22 and 1 future commingled well (potential G, F and D)

The total well count for the Hebron Field now uses all 52 of the available well slots (Table 12). In a success case, additional development could be possible, so strategic use of well slots must be considered with every drill well opportunity. Existing technologies such as multilateral completions and slot reclaims may be used to optimize future slot utility while maximizing targets. Considering the limited slot availability, the Proponent should provide details on efforts to reduce slot constraints.

Condition 1: Recognizing the limited availability of remaining drill slots on the *Hebron* Platform, the Proponent must describe efforts to reduce slot constraints through updates to the Resource Management Plan on an ongoing annual basis and in regular semi-annual subsurface meetings with Resource Management staff.

Table 12: Hebron Project Updated Well Count by Pool - Best Estimate (Source: ExxonMobil Canada Properties, 2022)

Pool	Reservoir/Compartment	Production Wells	Injection Wells	Total
Pool 1	Ben Nevis, D-94 Block	14	5	19
	Ben Nevis, I-13 Block	3	2	5
	Pool 1 Total	**17**	**7**	**24**
Pool 5	Hibernia Fm.	7	2	9
JDA Pools	JDA Fm.	12	5	17
Pool 2	Ben Nevis Fm.	0	1*	1*
Cuttings reinjection			1	1
Total		**36**	**16**	**52**

*Pool 2 gas injector completed to allow future back-production

Since well slot availability affects the entire Hebron Project, this annual update should include a timetable for predicted well slot reclaims or abandonments and plans for reuse. Discussions should also commence to determine appropriate criteria for slot abandonment (e.g. water cut or gas-oil ratio limitations, production handling constraints). It is recognized that this update would be forward-looking, and therefore will change with evolving field conditions and production data.

The Hebron Development Plan (Decision Report 2012.01) did not include gas injection or any other gas related depletion mechanisms such as water-alternating-gas injection for the JDA Formation, due to the higher subsurface pressure of the reservoir, which would require addition of compression equipment. The Proponent will continue to test the potential for other development strategies to optimize reservoir performance as new information becomes available. If any future strategies are outside the scope of the approved Development Plan for the JDA Formation, approval of another DPA will be required.

The well placement philosophy gives priority to reservoir quality insomuch as it achieves both high well productivity and high sweep efficiency. Production and injection wells will be drilled to target the best appraised and highest-confidence resource. As each new well is drilled, the information gathered will be used to optimize the placement of remaining wells.

The depletion plan relies primarily on dedicated standalone wells for some sands with the potential for well deepening to acquire data from other sands and potentially allow commingled production. The base depletion plan assumes one future commingled well targeting the G, F and D sands. Opportunity for additional commingled wells and to extend commingled production/injection options to other sands, will be assessed with potential implementation based on feasibility informed by subsurface, drilling and economic factors.

The development strategy will continue to be revised to optimize oil recovery depending on learnings from the development drilling program and early production performance. The Proponent will be expected to include updates about these opportunities or any changes from the base case depletion plan in the annual update to the Resource Management Plan.

7.5.1. JDA H Sand Development Strategy

The Hebron Development Plan (Decision Report 2012.01) base case development scenario for the JDA H Sand included three producers and a single water injector. The DPA base case development scenario for the JDA H Sand includes three dedicated producers and two water injectors. This is in addition to the existing L-93 22 smart well, also producing from the H Sand reservoir interval. The total number of wells may change due to a number of factors, including but not limited to the following:

- Learnings gathered during the initial development drilling program;
- Early production performance from this reservoir;
- Results of ongoing activities to improve both the reservoir description and the forecasted recovery efficiency.

There are currently two JDA H Sand development wells: the H Sand interval in L-93-22 and the recently drilled L-93 30Z horizontal oil producer. L-93 22 dynamic data assessment has indicated poor productivity and connectivity for the perforated H Sand interval. Minimal future volumes are anticipated from the H Sand through L-93 22.

Learnings from the dynamic performance of L-93 30Z were included in the addendum. To match L-93 30Z well performance, multiple geologic scenarios were contemplated with several interpretations tested using simulation modelling. Three simulated scenarios resulted in a reasonable history match.

The first simulation scenario was created by adding near well-bore baffles/boundaries to make a limited connected volume. History match edits were made near the L-93 30Z wellbore to honour production performance, including water production at the heel. The next simulation scenario that matched history was created by lowering the H Sand connectivity by distributing the sand as geobody objects in the geologic model (~1000 m in width x 15 m in thickness) and lowering transmissibility between objects. The last simulation scenario to match history required qualitative calibration of VpVs (compressional-to-shear velocity ratio) amplitudes resulting in a narrower seismic trend and smaller pore volume area limits connected volume and a new downside estimation (140 MMbbl STOOIP).

Due to the ability to history match multiple scenarios and its associated impact on future well placement and production expectations, additional H Sand data is required to refine the range of possible geologic outcomes. As a result, dedicated H Sand wells are being deferred in the rig schedule with emphasis being placed on strategic data collection to optimize the H Sand development strategy. The H Sand is located stratigraphically at the top of the JDA Formation so planned wells targeting deeper sands will encounter the H Sand interval. This will provide opportunities to collect additional static data to further delineate reservoir presence and extent. To collect dynamic data, pressures may be taken in future wells penetrating the H Sand. The Proponent is also proposing to inject in the H Sand through the first B Sand injector. Should the existing seismic be reprocessed or additional seismic data be collected, it will be used to evaluate and optimize future H Sand wells and placement.

All future producers are currently planned to be drilled as highly deviated to horizontal wells to provide increased wellbore contact with the reservoir to maximize initial oil rates and oil recovery. Injectors are planned to be deviated wells. A number of commingled opportunities are identified that would provide efficient data collection of a secondary sand interval from wells with a different primary target. A potential example for the H Sand includes, but is not limited to, injection in the North Valley H Sand through a planned B Sand water injector. Establishing injection in the H Sand through a water injector with an alternative primary target could provide a data point to evaluate connectivity to the existing H Sand producers with the potential to inform future H Sand wells and placement. Further optimization of this plan is ongoing and will influence final well count, well type and placements.

7.5.2. JDA B Sand Development Strategy

The Hebron Development Plan (Decision Report 2012.01) base depletion scenario for the JDA B Sand included a single producer and water injector pair. The DPA base depletion scenario for the B Sand includes drilling three development wells (two producers and one injector) to target the lower sand package in the main segment of the Hebron Horst.

A number of commingled opportunities are identified that would provide efficient data collection of a secondary sand interval from wells with a different primary target. Potential examples for the B Sand include, but are not limited to:

- Injection in the B Sand through a planned E/D injector;
  - The E/D injector is planned as an early well in the rig schedule and there is potential to gather timely B Sand data by extending and completing the well in that interval. This data could enable optimization of future B Sand wells.
- Production/injection in the B Sand through planned C Sand wells;
  - The C Sand accumulation is located at the crest of the Hebron Horst with limited well penetrations. L-93 29 encountered hydrocarbons and good quality reservoir in the B Sand at this location. The potential deepening of C Sand wells and collecting dynamic data in the B Sand in this area through commingled production/injection could reduce connectivity uncertainty in the B Sand, improve understanding of B Sand distribution and enable optimization of future B Sand wells.

The key subsurface uncertainties associated with the development of this resource are related to reservoir quality and the lateral extent of cemented sands. Production and geologic information will be key to resolving the subsurface uncertainties. The final well count, well type and locations may change based on performance data.

7.5.3. JDA G, F and D Sands Development Strategy

The proposed base depletion plan for G, F and D sands is a single-well commingled development targeting all three sands. The base case assumes a proactive commingling strategy with all sands completed and brought online at the same time. Other commingled strategies such as bottom-up and recompletion options are also being considered. The final well count, well type and strategy may change due to a number of factors including but not limited to:

- Results of ongoing activities to improve reservoir description, well placement and forecasted recovery efficiency;
- Data gathered during drilling through these sands;

- Learnings gathered during early production performance from these sands;
- Synergies between commingling strategy and overall reservoir management;
- Strategy considerations: reservoir drive, fluid types, pressure regime, differential depletion, drawdown management, etc.
- Decisions on advanced/smart completions technology implementation, ICV for zonal production control;
- Opportunity to drill and complete advanced well types such as multilaterals;
- Slot management;
- Opportunity for pressure management via commingled water injection;
- Opportunity to further delineate, appraise and develop more sands.

7.5.4. JDA E Sand Development Strategy

The DPA base depletion plan for JDA E Sand includes one production well supported by one water injection well targeting the main segment of the Horst Block. This is in addition to the existing L-93 22 smart well that already produced from the E Sand interval in an extended flow test. JDA E Sand production will initially be through the existing L-93 22 intelligent well completion. The water injector is planned to be initiated prior to bringing the L-93 22 E Sand interval back online, to provide pressure support. L-93 22 was not drilled with the E Sand as the primary target and its location is not optimized for E Sand sweep. The base depletion plan assumes a future up-dip E Sand producer to maximize sweep within the area of good reservoir quality.

Another consideration in the E Sand development strategy is the interpreted connection between the E and D sands. Pressure data indicates the E and D sands form a single E/D accumulation with a common OWC. While the current plan assumes dedicated wells for E Sand depletion, opportunities to include commingled production/injection of E Sand with D Sand and possibly other sands will be evaluated and may have an impact on the final number of wells required to develop this resource.

7.5.5. JDA C Sand Development Strategy

The DPA depletion plan for JDA C Sand is a three-well development. Two vertical producers are planned to be supported by a water injector placed at the edge of the water leg to ensure good sweep displacement. Improvements in reservoir and geological understanding of the sand during the development phase will play a key role in influencing the final well type, bottom hole locations and well count.

7.5.6. “Prime” Blocks Development Strategy

At the time of the DPA submission, no specific wells were assigned to the “Prime” blocks. It was recognized that further analysis and data collection could cause future development to capture high side resource. For future development decisions and continued optimization of the rig schedule, the Proponent recognized the potential of early data collection and continued the evaluation of the “Prime” blocks. As a result, revisions in the addendum document describe two wells (producers in a success case) planned to target the C’ and E’ blocks. Prioritization of data collection in the C’ and E’ was based on upside EUR potential. The drill schedule includes placeholders for two additional injectors supporting the initial wells. This represents a successful upside outcome of two oil producers and two water injectors. The Proponent recognizes the value of early planning for these opportunities in ongoing efforts to manage and optimize slot usage, preserve optionality and progress drill readiness if the upside is realized. Uncertainty in the presence and volume of hydrocarbon, in addition to reservoir presence and quality, remains a key concern and the Proponent characterizes success in this area as an upside outcome.

Should the C’ and E’ block wells prove successful, the remaining “Prime” blocks may also be assessed for economic development.

Recognizing the high degree of uncertainty of the “Prime” blocks, staff are encouraged by their inclusion early in the proposed drill schedule. In the interest of optimizing slot usage, and preserving optionality and drilling readiness, the Proponent should describe the definition of success for each of these “Prime” block wells at the time of ADW submission. This information should include the minimum resource required for primary depletion by one producer, minimum resource required for water injection support, as well as supporting economic evaluation of these criteria. This will provide clarity on decision making as field development progresses.

7.5.7. Gas Management Plan

The formation gas produced in association with oil production will be used principally to meet the fuel requirements for the production and drilling facilities. During periods when the volume of produced formation gas exceeds operational requirements, the surplus gas will be injected into one of the Hebron area reservoirs for storage and/or pressure maintenance purposes. Gas lift is the preferred artificial lift method so a portion of the produced gas will be continuously circulated within the production system to gas lift the production wells.

Several alternative options are available for gas injection and depending upon the overall gas injection requirements all of the options may be employed for asset gas management purposes:

- Per the Subsurface Storage License 1007, the Pool 2, Ben Nevis Reservoir of the Hebron Field was approved for the storage of produced gas from the Hebron Asset The current subsurface license was issued and effective for a term of three years commencing October 1, 2020;
- Gas injection in the I-13 Block (Pool 1) using the downdip WAG injectors. Base plan for I-13 injection is to alternate WAG cycles between the East and West flank on an annual basis;
- Gas injection in the crest of the D-94 block (Pool 1). The crestal injector, L-93 28, was drilled in 2021 and is currently injecting water. The well was designed for either water or gas injection and it is expected that a single switch from water to gas will occur after several years of water injection. The integrated flowstreams assume the well will switch to gas injection in 2026.

Under a steady state mode of operation, there will be continuous, low-rate background consumption of gas attributed to flare pilot combustion and potential valve and compressor seal leakage. There is a possibility that late in field life, there may be insufficient produced gas volumes to meet operational gas requirements. If this occurs, the re-injected gas stored in Pool 2 may be back-produced for use as operational gas. The Pool 2 gas injector was designed such that it can be converted into gas production if needed. The integrated flowstream assumes production of gas from Pool 2 beginning in 2038. The Pool 2 gas is not essential, as there is sufficient gas within Pool 1 to meet operational requirements through end of field life. However, the use of Pool 2 gas was found to be optimum as it enabled the gas cycling to continue at desired rates in Pool 1, which maximizes oil recovery.

The additional gas that will be produced as part of this DPA will not affect the Proponent's current approach to gas handling for the Hebron Field. Thus, staff consider the Proponent's approach to gas handling to be acceptable.

7.5.8. Integrated Project Flowstreams

The integrated flowstreams include volumes from pools in the Development Plan. The Hebron integrated project flowstreams were generated using simulation based results combined with a profile generator approach to account for downtime and facility capacities. Table 13 shows the facility capacities used for the integrated flowstreams.

Table 13: Hebron Facility Capacities (Source: ExxonMobil Canada Properties, 2022)

	Metric Units		Oilfield Units	
Design Element	**Units**	**Capacity**	**Units**	**Capacity**
Total Oil Production	km3/d	28.6	kbd	180
Total Water Production	km3/d	45.0	kbd	283
Total Liquid Production	km3/d	55.6	kbd	350
Total Gas Handling	Mm3/d	8.0	Mscfd	284
Total Water Injection	km3/d	59.1	kbd	372
HP Water injection	km3/d	12.2	kbd	77
MP Water injection	km3/d	50.9	kbd	320

Forecasts are presented in the Application (Figure 15 - Figure 18) on an annualized basis including the impact of downtime and do not represent the maximum or minimum stream day capacities that may occur. The inputs into the field forecast are based on an annual planning process that includes a multi-disciplinary assessment of the current performance.

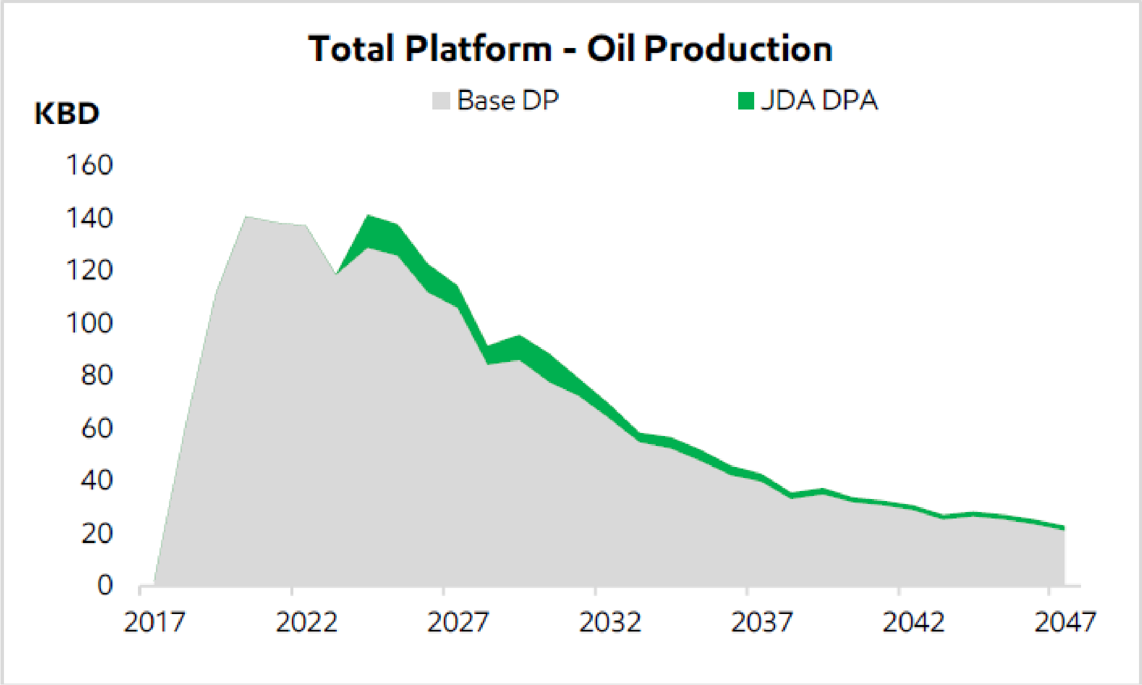

Figure 15: Production and Injection Flowstreams - Increment Associated with JDA DPA – Oil Production (Source: ExxonMobil Canada Properties, 2022)

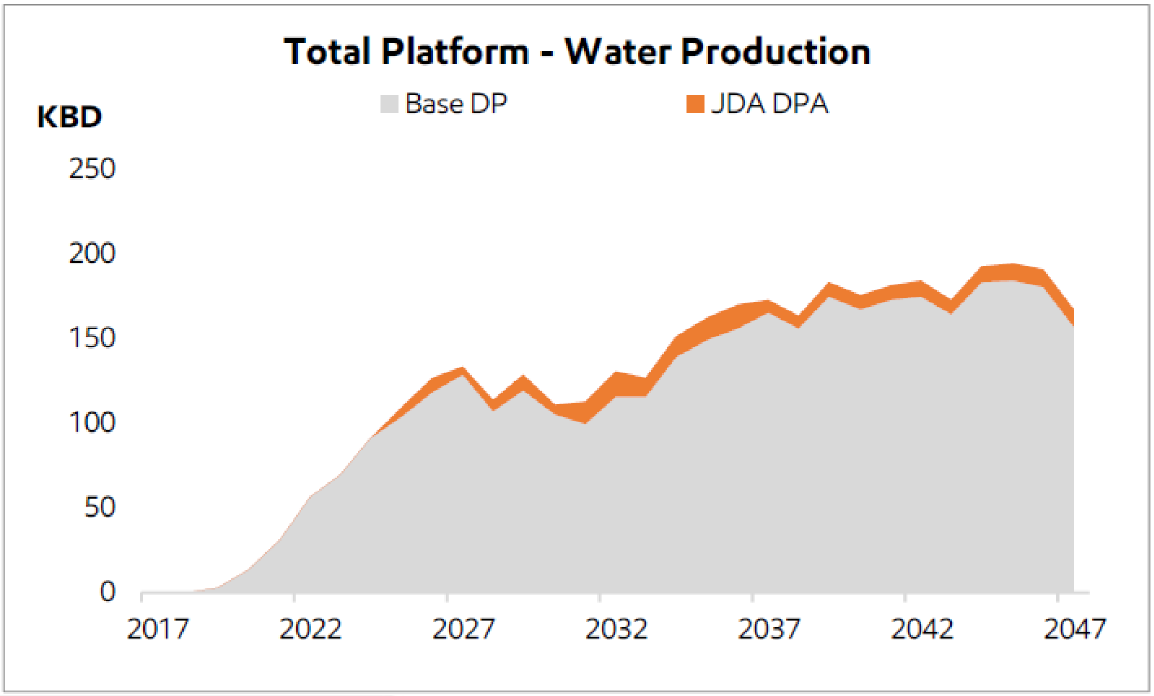

Figure 16: Production and Injection Flowstreams - Increment Associated with JDA DPA – Water Production (Source: ExxonMobil Canada Properties, 2022)

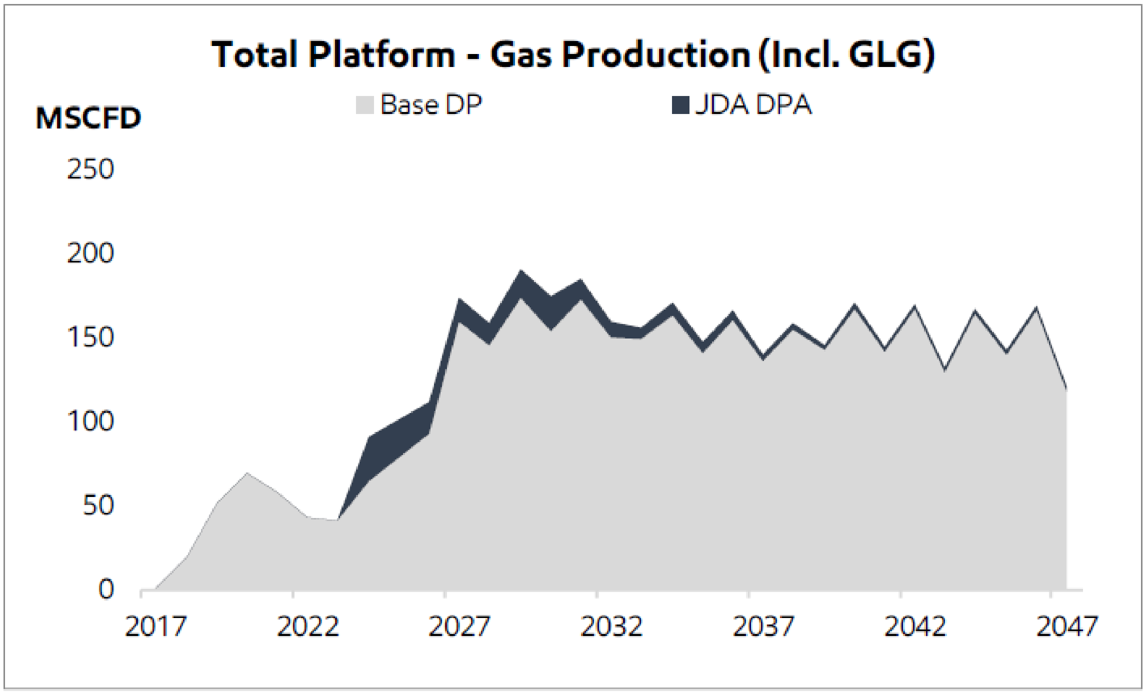

Figure 17: Production and Injection Flowstreams - Increment Associated with JDA DPA – Gas Production (Source: ExxonMobil Canada Properties, 2022)

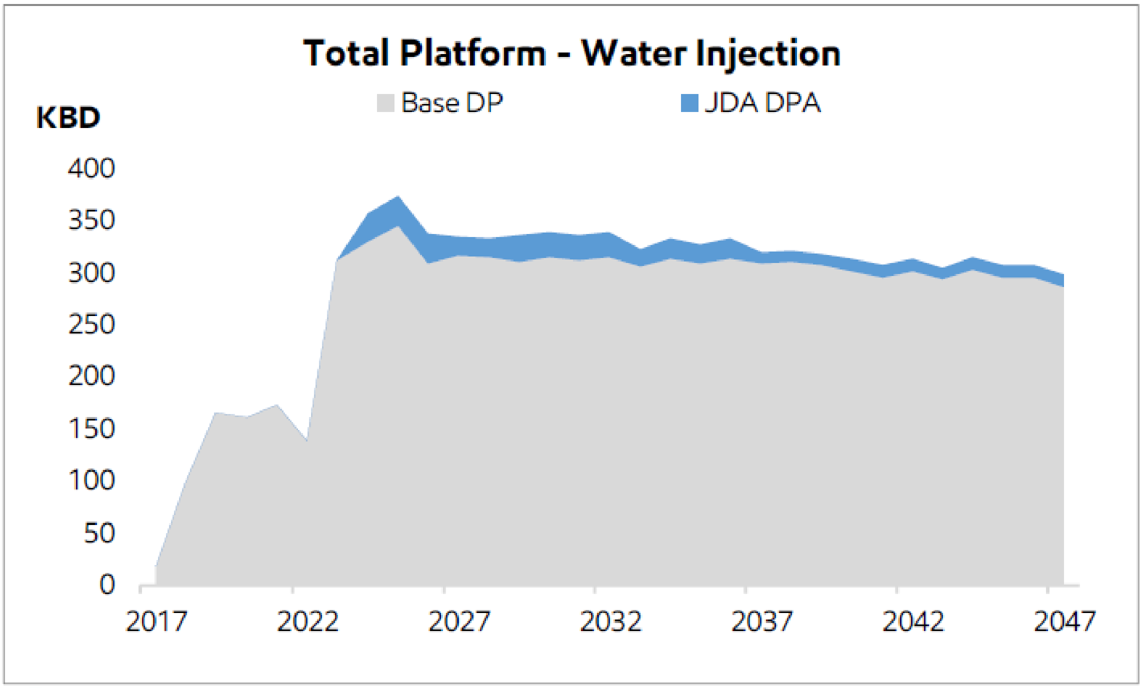

Figure 18: Production and Injection Flowstreams - Increment Associated with JDA DPA – Water Injection (Source: ExxonMobil Canada Properties, 2022)

Staff reviewed the full-field profiles to determine if there were any cause for concern regarding the Hebron facility handling capabilities. Considering the previously listed facility constraints, no significant issues were noted.

7.6. Rig Schedule

The long-term drill schedule is an evergreen plan that changes as additional information is gathered or technical work is completed. The recent H Sand learnings have highlighted a reduced confidence in future H Sand well locations due to the uncertainty in the geologic connectivity scenarios and impact on well performance. As a result, the H Sand wells are deferred to later in the rig schedule to allow for additional data collection.

Ongoing technical work on select “Prime” block opportunities and desire for early data acquisition has been identified as beneficial to assess upside potential. The rig schedule includes placeholders for the high side outcome where the “Prime” block wells are successful producers requiring injection support. It also includes a placeholder for an additional JDA commingled well in the event of a high side outcome through additional data collection for both B and H sands. This is done to enable consideration of the high side in well planning, slot optimization and preserving optionality.

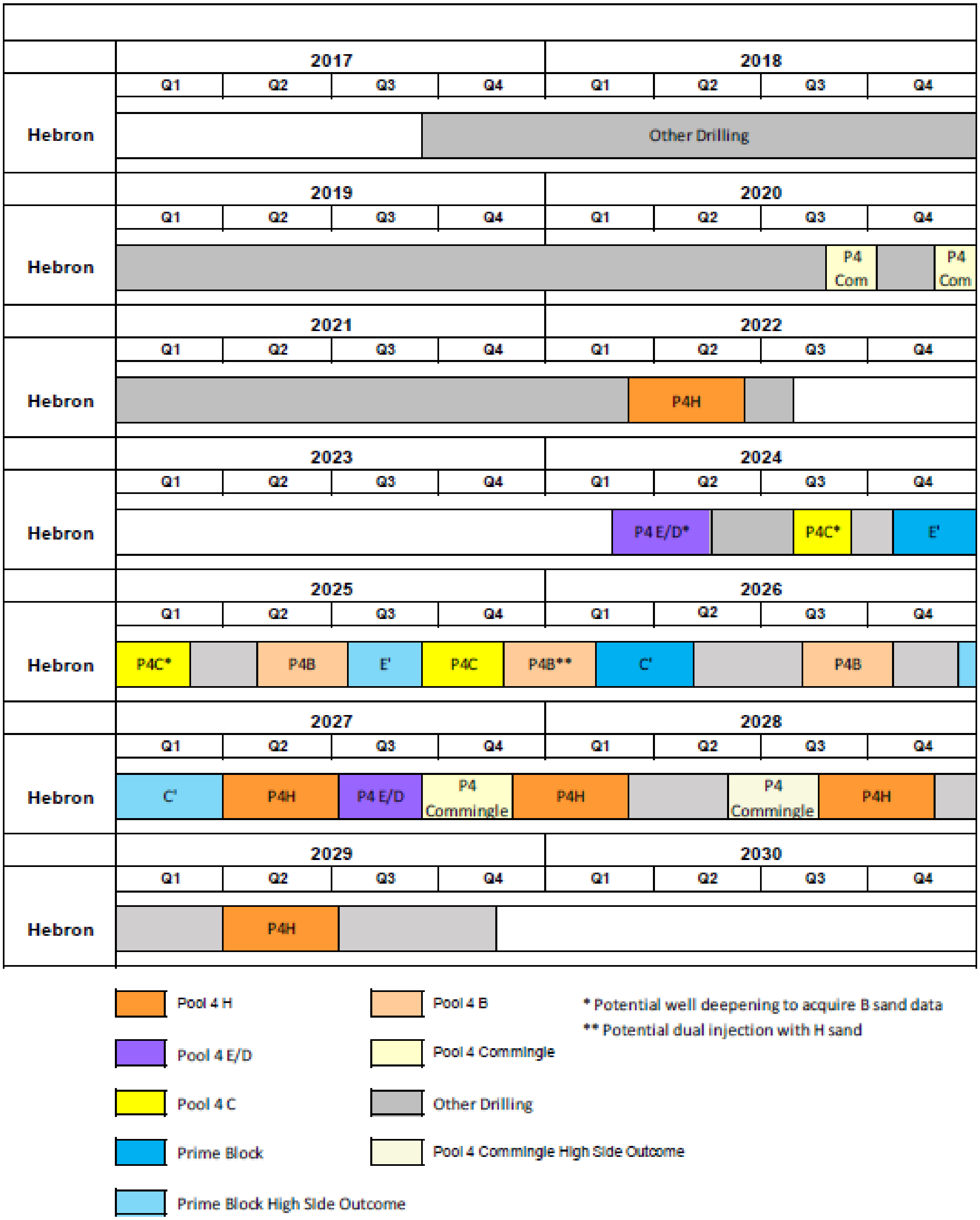

Figure 19: Integrated drill schedule, with high side potential (Source: ExxonMobil Canada Properties, 2023, addendum)

7.7. Reservoir Simulation

The simulation models submitted with the Application were not updated with the learnings from the addendum. Staff reviewed the simulation models and agreed that they represent reasonable interpretations of the expected reservoir behaviour considering the information that was available. However, the Proponent will be expected to provide updated simulation models when available and address any discrepancies from the expectations of the submitted simulation in annual updates to the Resource Management Plan.

7.7.1. H Sand Simulation Model Review

The Petrel project submitted with the Application includes predictive simulation cases to assess optimal development strategy of the H Sand. The dynamic data acquired from the L-93 22 well shows substantially lower productivity compared to predrill expectations while the DST in the M-04 exploration well indicated strong dynamic performance from the H Sand. The large range observed in dynamic performance was a key driver for the Proponent carrying a range of scenarios. Three geologic scenarios were selected for modelling, representing a range of connectivity and reservoir quality uncertainty. The scenario-based approach captures the uncertainty of lateral and vertical connectivity and sand quality, with the primary purpose being testing connectivity to optimize future well design and trajectories. For the purposes of the Application, the Best Estimate 2021 (moving averages) model was used as the basis for the H Sand development flowstreams.

The Best Estimate model represents a scenario with moderate connectivity and net to gross. The concept assumes a low sinuosity sandy braided fluvial complex comprised of amalgamated accretionary sandbars with bank-attached bars along the margin of the valley. The low quality, bank-attached sand bars are modelled to be deposited parallel to the valley's axis-edge. Shaley-islands (interfluves) can be formed and partially preserved within the main valley axis (low/non-net). The properties were distributed with moving average porosity distribution calibrated to seismic facies.

A new development well, L-93 30Z, was drilled in 2022, but at the time of the simulation model submission, early production data from this well were still being incorporated. Modelling work continues on the H Sand to incorporate the performance from this first horizontal producer and optimize the depletion plan for H Sand.

The Proponent's model used for simulation has STOOIP estimates of 27.99 MMm^3 (176 MMbbl) for the H Sand which is in agreement with the "Best Estimate" volume reported by the Proponent in Table 6-1 of the Application.

The fluid properties for the H Sand continue to be based on the M-04 data, as the samples acquired from L-93 22 could not be recombined because the rates were too low to measure the GOR accurately. The 3912 mTVDss OWC is interpreted to be perched based on the L-93 22 and M-04 data. These inputs are discussed in the Application and are consistent among all predictive cases. Staff reviewed these variables and agreed with how the Proponent applied them in the model.

Seven predictive simulation cases (Figure 20) were included in the model to test well count sensitivity for the H Sand. Based on simulation modelling and constrained by slot allocation, the Proponent selected a six-well development (three highly deviated to horizontal producers and three water injectors) as the base case depletion plan for the H Sand. Single producer/injector well pair depletion plans for the Main, North East Ramp and North East segments were also tested. There is potential to increase recovery from the H Sand through an additional horizontal well in the Main segment, should slots become available. An alternate well type with vertical producer wells was considered and found to be suboptimal in terms of both rate and recovery. Similar to the existing L-93 22, vertical well development might be considered if there is opportunity to develop the H Sand with other JDA sands through commingled production and injection. An alternate depletion plan with primary recovery scheme (three producers only) was tested and found to be suboptimal for resource recovery compared to the current depletion plan that includes pressure support by water injection.

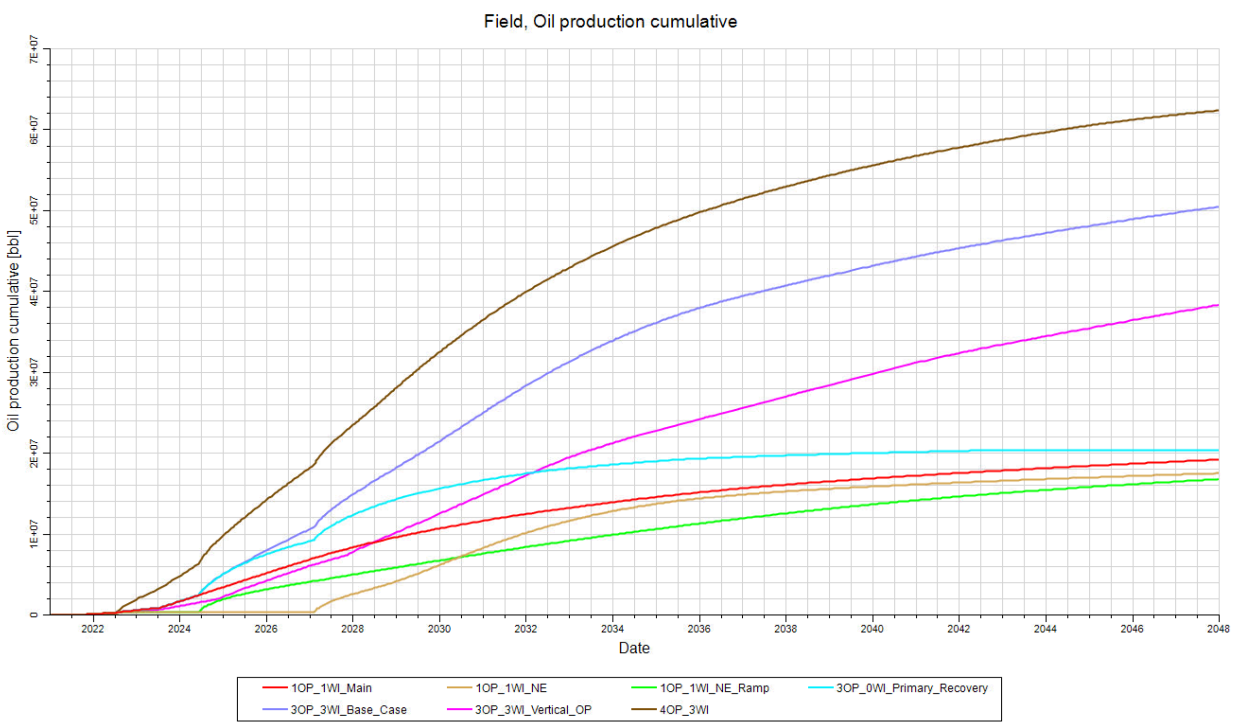

Figure 20: Cumulative Oil Production - H Sand Well Count Sensitivity (Source: ExxonMobil Petrel Project) OP = Oil Producer, WI = Water Injector

The first producer, L-93 30Z came online in June 2022 and the well schedule used in the model for the Proponent's base case plan simulation model assumes the first water injector comes online July 2023, followed by the second oil producer in June 2024. The second water injector is scheduled for November 2024, the third oil producer in February 2027 and the third water injector in November 2027 with production continuing until 2047. Since the submission of the simulation model for the H Sand, there have been learnings from the dynamic results of the L-93 30Z producer included in the addendum. Although the development strategy and well schedule for the H Sand has been altered to defer dedicated H Sand wells, the Proponent expects comparable recovery to the best estimate case of the simulation model. The resulting recoverable oil from this base case depletion scenario within the Proponent's simulation model is 8.0 MMm^3 (50.6 MMbbl), which is in agreement with the volumes reported by the Proponent in Section 4.4.1 of the Application and the addendum. Considering the STOOIP volumes in the model, this equates to a 30% recovery factor for the H Sand.

Staff completed a thorough review of the Proponent's simulation model have validated the simulation results of this study through running the model. Overall, staff found the Proponent's model for the H Sand and the assumptions used to be reasonable and appropriate.

7.7.2. G, F and D sands Simulation Model Review

The Petrel project submitted with the Application includes history matched simulation cases for the G sand as well predictive simulation cases to assess optimal development strategy of the G, F and D sands.

The reservoir engineering inputs to the model are discussed in the Application, and they include relative permeability data, fluid characterization and fluid contacts. These inputs are consistent among all of the history matched and predictive cases. Staff reviewed these variables and agreed with how the Proponent has applied them within the model.

Once the reservoir engineering inputs were defined, the Proponent used dynamic data to assess or improve the performance match of the modelling of the sands prior to completing predictive simulations. Production data exists for the G Sand from the I-13 delineation well and although the G Sand did not flow in the L-93 22 development well, pressure data was captured from this sand. The G Sand simulation model had insufficient productivity when compared with the I-13 DST data. The L-93 22 static results and simulation model indicated sufficient productivity for the G Sand to flow, however, no flow was achieved. Considering this wide range of observations, the Proponent could not perform any edits to the G Sand simulation model to match the dynamic data. No production has occurred from the D and F sands to date, and thus no history matching has been done for those sands. Accordingly, the Proponent's model used for simulation has STOOIP estimates of 12.2 MMm^3 (76.9 MMbbl) for the G Sand, 9.3 MMm^3 (58.3 MMbbl) for the F Sand, and 1.8 MMm^3 (11.4 MMbbl) for the D Sand, which is in agreement with the "Best Estimate" volumes reported by the Proponent in Table 6-1 of the Application.

Ten predictive simulation cases were run to test different development scenarios for each of the sands (G, F and D) as shown in Figure 21. The development strategy used for each of these predictive cases was assessed and this includes details on the proposed depletion schemes, planned well locations, well scheduling, and well production and injection constraints. Each of the sands (G, F and D) were assessed individually with a single horizontal oil producer versus a vertical oil producer; as well as with water injection support and without. A synergized simulation case was also completed where a single vertical oil producer was completed to produce from all three of the reservoir sands without any injection support. Ultimately, based on simulation modelling and slot allocation constraints, the Proponent has selected the single oil producer commingling production across all three of the sands as their base case depletion plan for these sands.

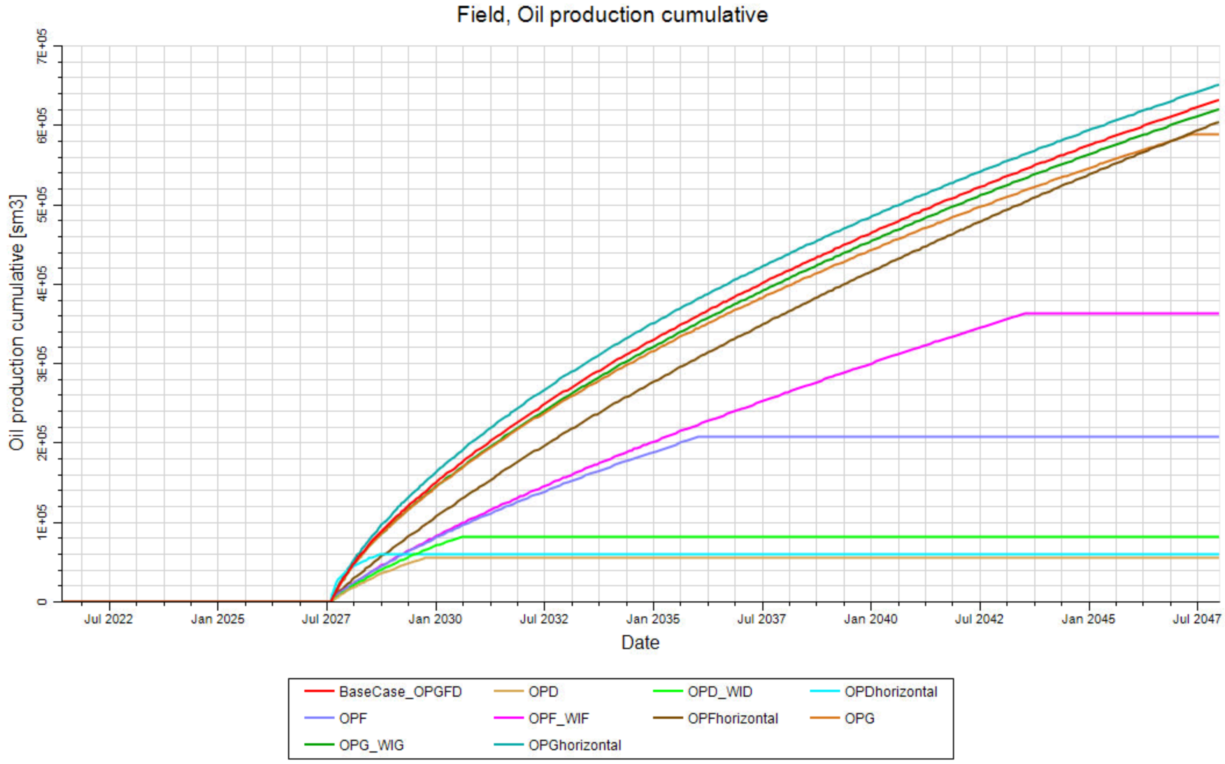

Figure 21: Cumulative Oil Production - G, F, D sands Well Sensitivity (Source: ExxonMobil Petrel Project)
OP = Oil Producer, WI = Water Injector

The well schedule used in the model for the Proponent's base case plan assumes the corresponding producer comes online May 1, 2027 and continues to produce until 2047. The resulting recoverable oil from this base-case depletion scenario within the Proponent's simulation model is 0.63 MMm^3 (4.0 MMbbl), which is in agreement with the volumes reported in Section 4.4.2 of the Application. Considering the STOOIP volumes in the model, this equates to a 3% recovery factor for the G, F, and D sands, which is within the range of expected recoveries for primary production.

Staff completed a thorough review of the Proponent's simulation model and validated the simulation results through running the model to confirm suitability of the selected commingled concept. The study has shown favorable results for dedicated deviated wells in the G and F sands in particular should slot constraints be alleviated in the future. The Proponent has identified this potential in the Application with additional data to be collected through these sands as development drilling occurs targeting the deeper sands (E and B), this data will be used to further refine the modelling work and continue to evaluate that potential. Overall, staff found the Proponent's model and the assumptions used to be reasonable and appropriate.

7.7.3. E Sand Simulation Model Review

The Petrel project submitted with the Application includes history matched simulation cases as well predictive simulation cases to assess the optimal development strategy for the E Sand.

The reservoir engineering inputs used to build the simulation model for the E Sand include relative permeability, fluid characterization data, and fluid contacts based on data acquired from the L-93 22 well. These inputs are discussed in the Application and are consistent among all of the predictive cases. Staff reviewed these variables and agreed with how the Proponent applied them within the model.

Once the reservoir engineering inputs were defined, the Proponent used dynamic production data from the L-93 22 well to assess or improve the performance match of the geological modelling of the sands prior to completing predictive simulations. Section 3.7.2.3 in the Application discusses the history match edits that were made to the geological model to get a good match to the dynamic data. Accordingly, the Proponent's model used for simulation has STOOIP estimates of 5.95 MMm^3 (37.4 MMbbl) for the E Sand which is in agreement with the "Best Estimate" volume reported by the Proponent in Table 6-1 of the Application.

Six predictive simulation cases were included in the model to test different development scenarios for the E Sand as shown in Figure 22. The development strategy used for each of these predictive cases was assessed and includes details on the proposed depletion schemes, planned well locations, well scheduling, and well production and injection constraints. The results of a number of sensitivities completed through simulation are included in the Application. Figure 4-10 of the Application includes the results of a study to assess the optimal well count for the E Sand development using strictly vertical producers. Figure 4-11 of the Application includes the results of a study to assess different well orientations (horizontal and deviated wells). Figure 4-27 of the Application includes the results of a study to assess water injection support versus no injection support (primary production). Ultimately, based on simulation modelling and constrained by slot allocation the Proponent has selected a three well development using the existing E Sand completion in the L-93 22 well, as well a new oil producer supported by a new water injector, as their base case depletion plan for this sand.

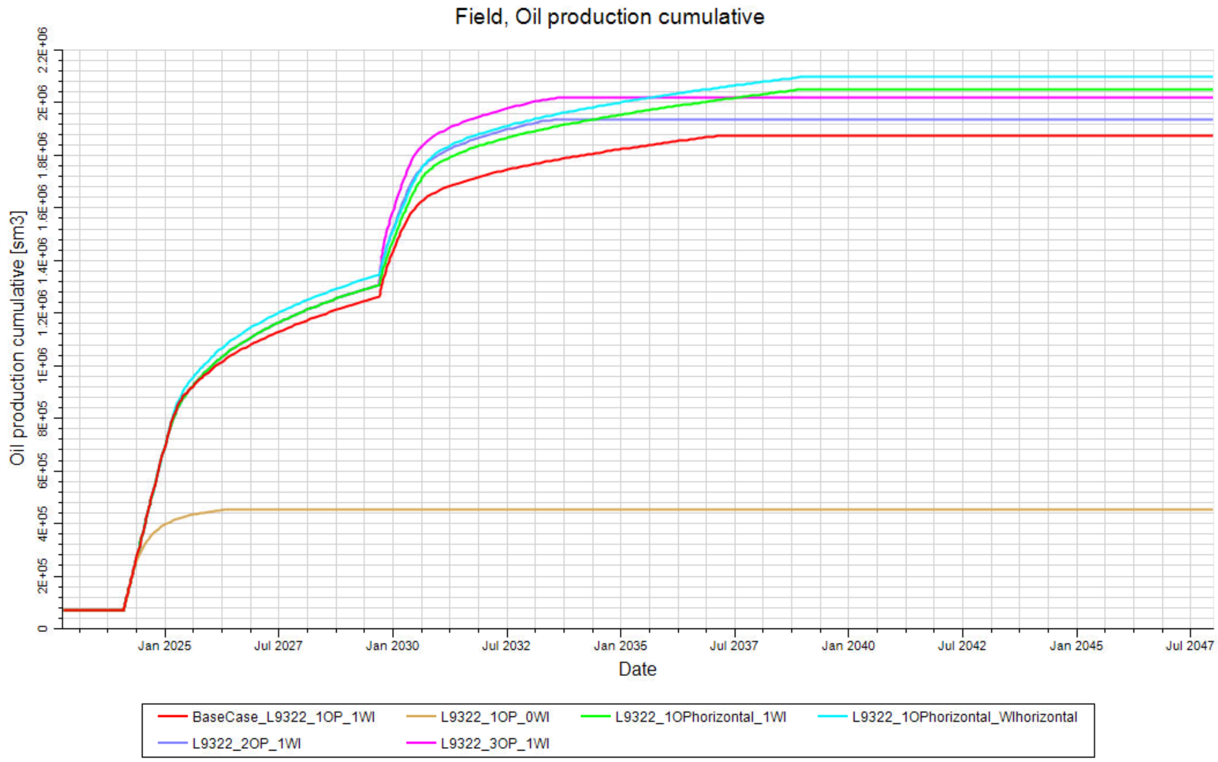

Figure 22: Cumulative Oil Production – E Sand Well Sensitivity (Source: ExxonMobil Petrel Project)
OP = Oil Producer, WI = Water Injector

The well timing used for the Proponent's base case simulation model assumes the L-93 22 oil producer starts producing again from the E Sand in January 2024 with the water injector coming online at that time. The second oil producer is set to come online September 2029 with production from the E Sand concluding in 2037. The resulting recoverable oil from this base-case depletion scenario within the Proponent's simulation model is 1.88 MMm^3 (11.8 MMbbl) for the E Sand, which includes previous production from the E Sand from the L-93 22. Considering the STOOIP volumes in the model, this equates to a 32% recovery factor for the E Sand development.

Staff completed a thorough review of the Proponent's simulation model and validated the simulation results of this study through running the model internally. Staff are in agreement with the selected concept. The simulation sensitivity studies indicate potential to increase recovery from the E Sand through additional wells and use of horizontal or deviated wells. The Proponent noted this in the Application and will continue to evaluate the option as more data is acquired. Additionally, it has been noted that there is potential to develop this sand concurrently with other sands through commingled production and/or injection, which could lead to greater development of the sand or well slot optimizations. Overall, staff found the Proponent's model for the E Sand and the assumptions used to be reasonable and appropriate.

7.7.4. C Sand Simulation Model Review

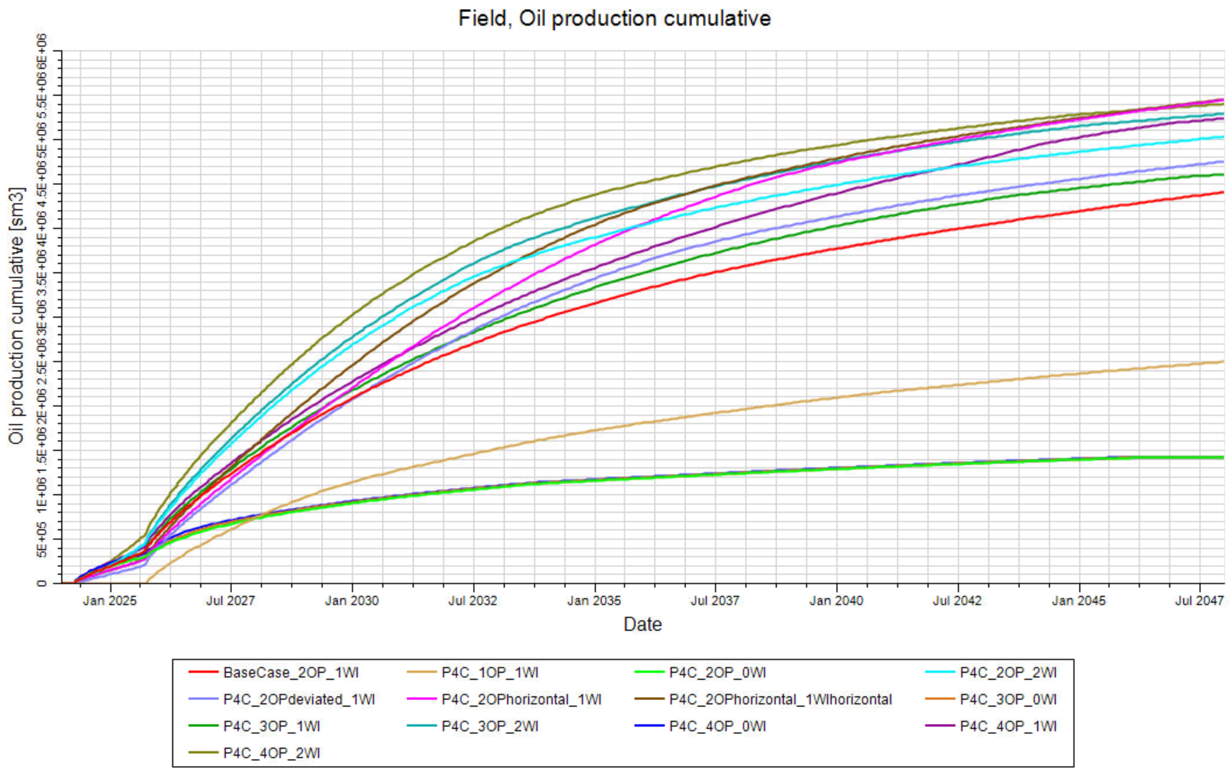

Figure 23: Cumulative Oil Production – C Sand Well Sensitivity (Source: ExxonMobil Petrel Project)
OP = Oil Producer, WI = Water Injector

The well schedule used in the model for the base case plan assumes the first oil producer comes online March 2024, followed by the water injector online August 2024, and the second oil producer online August 2025. Production is assumed to continue until 2047. The resulting recoverable oil from this base-case depletion scenario is 4.42 MMm^3 (27.8 MMbbl), which is in agreement with the volumes reported by the Proponent's in Section 4.4.4 of the Application. Considering the STOOIP volumes in the model, this equates to a 30% recovery factor for the C Sand development.

Staff completed a thorough review of the Proponent's simulation model and have validated the simulation results of this study through running the model internally, and agree with the selected concept. The well count sensitivity study indicates the potential to increase recovery from the C Sand through additional wells should slot constraints be alleviated. Additionally, simulation has shown favorable results for horizontal wells to increase overall recovery. This is noted in the Application and The Proponent will continue to evaluate the options as more data is acquired. Overall, staff found the Proponent's model for the C Sand and the assumptions used to be reasonable and appropriate.

7.7.5. B Sand Simulation Model Review

The Petrel project submitted with the Application includes history matched simulation cases as well predictive simulation cases to assess the optimal development strategy for the B Sand.

The reservoir engineering inputs discussed in the Application include relative permeability data, fluid characterization and fluid contacts. These were used to build the simulation model for the B Sand and are consistent among all of the history matched and predictive cases. Staff reviewed these variables and agreed with how the Proponent applied them in the model.

Once the reservoir engineering inputs were defined, the Proponent used dynamic production data from the L-93 22 well as well as pressure data from the L-93 29 well to assess or improve the performance match of the geological modelling prior to completing predictive simulations. Section 3.7.2.4 in the Application discusses the history match edits that were made to the geological model to get a good match to the dynamic data. Accordingly, the Proponent’s model used for simulation has STOOIP estimates of 17.7 MMm^3 (111.4 MMbbl) for the B Sand which is in agreement with the “Best Estimate” volume reported by the Proponent in Table 6-1 of the Application.

Ten predictive simulation cases were included in the model to test different development scenarios for the B Sand as shown in Figure 24. The development strategy used for each of these predictive cases was assessed and includes details on the proposed depletion schemes, planned well locations, well scheduling, and well production and injection constraints. The results of a number of sensitivities completed through simulation are included in the Application. Figure 4-14 of the Application includes the results of a study to assess the optimal well count for B Sand development. Figure 4-15 includes the results of a study to assess different well orientations. Figure 4-33 of the Application includes results of a study to assess water injection support versus no injection support (primary production). Ultimately, based on simulation modelling and constrained by slot allocation, the Proponent has selected a three well development (two vertical oil producers and one horizontal water injector) as the base case depletion plan for this sand.

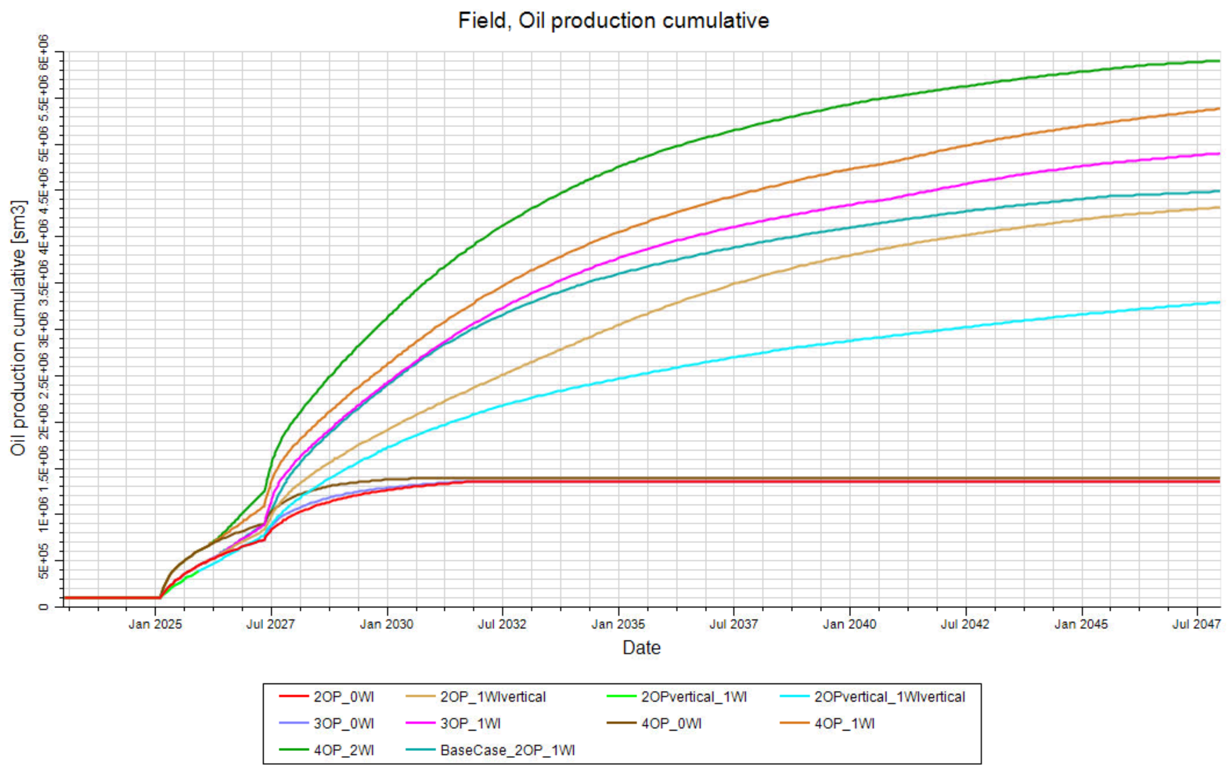

Figure 24: Cumulative Oil Production – B Sand Well Sensitivity (Source: ExxonMobil Petrel Project)
OP = Oil Producer, WI = Water Injector

The well schedule used in the model for the Proponent's base case plan assumes the first oil producer comes online March 2025, followed by the water injector online January 2026, and the second oil producer online May 2027 with production continuing until 2047. The resulting recoverable oil from this base-case depletion scenario within the Proponent's simulation model is 4.51 MMm^3 (28.33 MMbbl) for the B Sand, which includes previous production from the B Sand from the L-93 22. Considering the STOOIP volumes in the model, this equates to a 25% recovery factor for the B Sand development.

Staff reviewed the Proponent's simulation model and have validated the simulation results of this study through running the model internally. Staff are in agreement with the selected concept. The simulation sensitivity studies indicates the potential to increase recovery from the B sand by drilling additional wells and using horizontal wells. This is noted this in the Application and the Proponent will continue to evaluate the option as more data is acquired. Additionally, there is potential to develop this sand concurrently with other sands through commingled production and/or injection, which could lead to recovery from the sand or well slot optimization. Overall, staff found the Proponent's model for the B Sand and the assumptions used to be reasonable and appropriate.

7.8. Estimated Ultimate Recovery

The Application presented the Proponent's recoverable estimates for the JDA Formation H, G, F, E, D, C and B sands within the Horst Block as well as the C Sand in the C' Block and the Lower Hibernia Sand in the E' Block.

Staff constructed an independent geological model however, did not construct independent reservoir simulation models. Staff calculated low, most likely and high side recoverable estimates using a combination of recovery factor ranges, STOOIP values from the C-NLOPB's geological model, assessment of the Proponent's geological and simulation models.

For the "Prime" blocks, there is uncertainty associated with the fluid contacts and the possibility of shallower perched contacts. The potential perched water could significantly reduce the STOOIP, and therefore the EUR, in unpenetrated fault blocks. The C' Block in the C Sand and E' Block in the Lower Hibernia Sand are included in the drill schedule; however, the Proponent characterizes success in this area as an upside outcome due to the uncertainty in the presence and volume of hydrocarbon. In addition, reservoir presence and quality remains a key concern. The Proponent's approach for upside EUR was based on applying a common recovery factor of 30% to the surrounding fault blocks. This is a simple analogue methodology, reflecting observations in fields and reservoirs with similar attributes.

Staff do not agree that the C Sand in the C' Block and the Lower Hibernia Sand in the E' Block should be considered upside estimates, as these blocks are in the drill schedule, are adjacent fault blocks that have significant juxtaposition with oil-bearing sands in the main Horst Block. They are assumed to be oil bearing and in pressure communication on a geological timescale. For these reasons, staff have included these blocks in the recoverable oil volume estimates for the JDA Formation.

A comparison of the Proponent's and C-NLOPB's recoverable oil volume estimates for the JDA Formation are shown in Table 14.

Table 14: C-NLOPB vs. ExxonMobil estimated ultimate recoverable (EUR) oil volume by sand as per the proposed development scheme.

Sand	Fault Block	Units	Downside		Best Estimate		Upside	
			ExxonMobil	C-NLOPB	ExxonMobil	C-NLOPB	ExxonMobil	C-NLOPB
H North Valley	Horst	MMbbl	29.4	26.7	50.7	42.5	72.0	72.6
		MMm^3	4.7	4.2	8.1	6.8	11.4	11.5
G	Horst A’	MMbbl	1.1	1.4	2.1	3.1	40.4	3.6
		MMm^3	0.2	0.2	0.3	0.5	6.4	0.6
F	Horst A’	MMbbl	0.8	0.7	1.6	1.5	30.6	1.8
		MMm^3	0.1	0.1	0.3	0.2	4.9	0.3
E	Horst A’	MMbbl	5.6	9.1	11.4	13.8	19.6	20.3
		MMm^3	0.9	1.5	1.8	2.2	3.1	3.2
D	Horst A’	MMbbl	0.2	0.0	0.3	0.1	6.0	0.1
		MMm^3	0.0	0.0	0.1	0.0	1.0	0.0
C	Horst A’	MMbbl	9.3	16.5	27.8	25.6	48.3	37.2
		MMm^3	1.5	2.6	4.4	4.1	7.7	5.9
B	Horst A’	MMbbl	16.7	20.0	28.2	30.7	58.5	44.6
		MMm^3	2.7	3.2	4.5	4.9	9.3	7.1
C	C’	MMbbl	-	9.7	-	14.2	18.5	24.6
		MMm^3	-	1.5	-	2.3	2.9	3.9
Lower Hibernia	E’	MMbbl	-	25.4	-	33.8	50.7	59.2
		MMm^3	-	4.0	-	5.4	8.1	9.4
Total		MMbbl	63.0	109.5	122.1	165.3	344.6	263.8
		MMm^3	10.0	17.4	19.5	26.3	54.8	42.0

Staff’s most likely recoverable estimate of 26.3 MMm^3 (165.3 MMbbl) is higher than the Proponent’s estimate due to the inclusion of the “Prime” blocks.

It should be noted that staff’s most likely EUR of 26.3 MMm^3 (165.3 MMbbl) is an increase of 5.3 MMm^3 (33.3 MMbbl) from the previous estimate of 21 (132 MMbbl) at the time of the Hebron Development Plan (Decision Report 2012.01).

Should the Proponent acquire data on the other “Prime” blocks and go forward with development the recoverable oil volumes will need to be revised to include those blocks.

Condition 2: The Proponent must continue efforts to de-risk the “Prime” blocks and other upside resources in the Jeanne d’Arc Formation and provide details of this work in the annual update to the Resource Management Plan and in regular semi-annual subsurface meetings with Resource Management staff.

Staff completed a recoverable gas assessment using C-NLOPB’s EUR oil volumes and fluid properties for each sand (Table 15).

Table 15: C-NLOPB Recoverable gas estimates

Sand	Fault Block	Units	Downside C-NLOPB	Best Estimate C-NLOPB	Upside C-NLOPB
H North Valley	Horst	GCF	15.5	24.9	42.0
		Gm^3	0.4	0.7	1.2
G	Horst A'	GCF	1.1	2.2	2.6
		Gm^3	0.0	0.1	0.1
F	Horst A'	GCF	0.5	1.0	1.3
		Gm^3	0.0	0.0	0.0
E	Horst A'	GCF	21.3	32.2	47.3
		Gm^3	0.6	0.9	1.3
D	Horst A'	GCF	0.0	0.1	0.1
		Gm^3	0.0	0.0	0.0
C	Horst A'	GCF	27.4	42.5	61.7
		Gm^3	0.8	1.2	1.7
B	Horst A'	GCF	35.6	54.7	79.6
		Gm^3	1.0	1.5	2.2
C	C'	GCF	0.0	0.0	17.0
		Gm^3	0.0	0.0	0.5
Lower Hibernia	E'	GCF	0.0	0.0	41.0
		Gm^3	0.0	0.0	1.2
Total		GCF	101.4	157.6	292.5
		Gm^3	2.9	4.4	8.2

7.9. Deferred Developments

The Hebron Development Plan (Decision 2012.01) identified additional areas within the Hebron Field and surrounding area where oil and gas accumulations have been tested or where hydrocarbon potential exists that were not included for approval. These deferred developments and prospects provide potential for upside development. The Application proposes moving the remaining known JDA Formation hydrocarbons from deferred development, to a status of being approved for development.

The largest volumes of discovered resources that will be still considered deferred development are in Pools 2 and 3. Condition 2012.01.16 of the Development Plan approval stated that a Development Plan Amendment for Pool 3 would be required once additional data is acquired through appraisal drilling or a pilot scheme acceptable to the Board. Changes to the depletion plan proposed in the Application will create a situation of well slot constraint, which likely precludes the use of the GBS for full development of Pool 3. Therefore, the Proponent will be required to re-evaluate plans for future development of these pools and provide an update to the C-NLOPB. In the interest of ensuring conservation of resources and optimizing recovery from the full field, staff are recommending the following condition:

Condition 3: The Proponent must continue efforts to evaluate Pools 2 and 3 and other upside resources and provide details in the annual update to the Resource Management Plan and in regular semi-annual subsurface meetings with Resource Management staff. The Proponent must submit a report to the Regulator within two years of this Decision Report that explains plans to de-risk development of Pools 2 and 3.

This report should describe the assumptions, uncertainties and constraints (including resource uncertainty, drilling constraints, facilities limitations, etc.), and include economic analysis and a tentative timetable for potential development. Since these aspects will change with time, it is expected that updates will be provided on ongoing basis.

7.10. Conclusion and Recommendation

The Application proposes developing the remaining sands in the JDA Formation using the same general approach to Hebron Project development, including existing facilities and drill well slots, recovery methods and systems.

The Proponent indicates that 19.4 MMm^3 (122.1 MMbbl) can be produced from the JDA Formation. Staff's estimate for the total oil recoverable is 26.3 MMm^3 (165.3 MMbbl).

The depletion strategy proposed for the JDA Formation is secondary recovery by water flood. The Application proposes drilling 12 producers and five water injectors, of which seven producers and two water injectors are newly proposed in this DPA. The total well count for the Hebron Field is now 52 wells of the 52 well slots available. In a success case, additional development could be possible so strategic use of well slots should be considered with every drill well opportunity. Existing technologies such as slot reclaims and multilateral completions may be used to optimize future slot utility while maximizing targets. Considering the limited slot availability, the Proponent should provide details on efforts to reduce slot constraints.

Staff's review of the Application, including the Proponent's seismic interpretations, production history, geological models and reservoir simulation models indicates that the proposal is reasonable and the development strategy is appropriate for the oil resources in remaining JDA Formation sands.

Using existing geological data, staff constructed a geological model for the JDA Formation to provide independent estimates of STOOIP and to confirm the estimates provided in the Application. While there are some discrepancies between the Proponent's and staff's volumetric estimates due to slightly different interpretations and modelling procedures, overall, the methods used by the Proponent are considered appropriate and reasonable.

The additional gas that will be produced as part of this DPA will not affect the Proponent's current approach to gas handling for the Hebron Field. Thus, staff consider the Proponent's approach to gas handling to be acceptable.

The incremental production volumes associated with this DPA were assessed against facility capacities. Staff have not identified any negative impact from the additional volumes.

The Proponent will be expected to provide updated comparisons of reservoir performance and reservoir simulation model predictions in the annual update to the Resource Management Plan for the JDA Formation.

Staff agree with the Application from a resource management perspective and recommend approval subject to the following conditions:

Condition 1: Recognizing the limited availability of remaining drill slots on the *Hebron* Platform, the Proponent must describe efforts to reduce slot constraints through updates to the Resource Management Plan on an ongoing annual basis and in regular semi-annual subsurface meetings with Resource Management staff.

Condition 2: The Proponent must continue efforts to de-risk the "Prime" blocks and other upside resources in the Jeanne d'Arc Formation and provide details of this work in the annual update to the Resource Management Plan and in regular semi-annual subsurface meetings with Resource Management staff.

Condition 3: The Proponent must continue efforts to evaluate Pools 2 and 3 and other upside resources and provide details in the annual update to the Resource Management Plan and in regular semi-annual subsurface meetings with Resource Management staff. The Proponent must submit a report to the Regulator within two years of this Decision Report that explains plans to de-risk development of Pools 2 and 3.

8. Operations

The following is an analysis of the Application in relation to well operations, as well as the certification of the proposed installation and facilities.

8.1. Well Operations

The well count adjustment to 12 production wells and five water injection wells total in the JDA Formation inclusive of commingled wells and "Prime" Blocks wells to develop the sands B through H uses existing facilities, well slots, recovery methods and systems. No infrastructure related modifications are required to the Hebron Platform to drill and complete these wells. As such, section 4.2.5 of the Hebron Development Plan Amendment includes only the amended information from Section 7.0 of the approved Hebron Development Plan.

The well designs are deemed achievable with the existing rig equipment and practices. The drillability of JDA wells using existing facilities has already been demonstrated in drilling the L-93 22 and L-93 29 wells where the additional JDA sands were delineated. The Proponent has also confirmed the well control systems inclusive of BOP, choke and kill manifold, mud gas separator, trip tank, PVT and flow monitoring systems meet or exceed requirements for development of the JDA resource.

The three dimensional well trajectory profiles are achievable with standard hole and casing sizes. However, given the depth of the JDA Formation, intermediate and production casing strings will generally be set deeper and/or additional liners may be required in some cases. Standard Class G cement is planned for cementing operations, and cement tops will be planned to isolate hydrocarbon-containing intervals. Completion strategy may be cased or open hole depending on the individual well design and sand control needs. Adequate downhole barriers will be used that are consistent with current Hebron well design. Multi-function wells are not planned, although if need arises for further cuttings reinjection (CRI) opportunity, consideration may be given to future operation in the open annuli of water injection wellbores. Plans presently are to continue with use of dedicated CRI wells. Multilateral well designs may also be considered in future for slot optimization purposes.

All of the above well design considerations are further refined and finalized in the detailed well design stage and evaluated through the Approval to Drill a Well process. Should any new technologies or applications be proposed for use on the Hebron Platform, or should any change in service of a well be requested, the Proponent would need to ensure that its application for Operations Authorization addresses the modifications, in addition to all other regulatory requirements pertaining to the authorization and approval process. All management of change processes internal to the Proponent's management system must be completed and signed off by the appropriate personnel. Where applicable within its scope of verification activities, the Certifying Authority must acknowledge that it is satisfied with the changes proposed. Additionally, note that well specific details associated with a change in well service will have to be satisfactorily outlined in supporting documentation that demonstrates compliance with the regulations and with good industry practice. This will be evaluated through the Approval to Alter the Condition of a Well process. The Proponent must seek C-NLOPB approval prior to conducting any operations related to the proposed change in service.

8.2. Certification

Based on the scope identified, the Proponent identifies that the resources will be developed using the existing facilities and drill well slots, recovery methods and systems.

All work outlined as part of the Application is consistent and captured under the currently approved Scope of Work for the *Hebron* Installation.

8.3. Recommendation

Activities in connection with this Application will be managed in accordance with established processes, procedures and applicable well approvals. Based on this, Operations staff recommend approval of this Application.