HEBRON DEVELOPMENT PLAN AMENDMENT 2022

Jeanne d'Arc Formation Sand Intervals

Abstract

Development Plan Amendment to include sands encountered in the Jeanne d'Arc Formation between the H and B sands (included in the Development Plan) and to incorporate fault blocks connected by juxtaposition to the Hebron Horst Block.

ExxonMobil Canada Properties

On behalf of the Hebron Co-Venturers

Executive Summary

ExxonMobil Canada Properties (ExxonMobil), as operator of the Hebron Project, on behalf of itself and the other Hebron co-venturers, Chevron Canada Limited, Suncor Energy Inc., Equinor Canada Limited, and Nalcor Energy – Oil and Gas Inc., is seeking approval to develop the remaining sands within the Hebron Jeanne d'Arc (JDA) Formation.

The plan is to develop this resource 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 and environmental factors associated with the existing Hebron facility. In a success case, this development may represent up to approximately 5% of the expected ultimate recovery (EUR) at Hebron. The development of this resource will assist in offsetting the natural decline in production at Hebron as the next step to optimizing Hebron area resources consistent with good oil field practice.

The JDA Formation is the deepest reservoir at Hebron and is Kimmeridgian to Tithonian in age. The topmost (H) and bottommost (B) sands were included in the Development Plan as sufficient data were available to progress a reservoir exploitation plan. The remaining sands within the JDA Formation have been delineated by recent drillwells L-93 22 and L-93 29 and are the subject of this Development Plan Amendment (DPA) application. The area proposed for development sits directly below the Hebron Platform and includes the Hebron Horst Block along with small fault blocks to the east and south where reservoir is juxtaposed against reservoir. Inclusion of these fault blocks is intended to capture the full extent of the hydrocarbon accumulation such that development of the accumulation is optimized.

The Hebron base depletion plan scenario originally considered 38 drill wells however, the Hebron platform was constructed to include 52 drillwell slots. This DPA scenario considers development of 51 wells (50 producer/injector wells and one cuttings reinjection well) and represents the current best estimate of development wells at Hebron. The well count addition associated with the JDA DPA is six (four oil producer wells and two water injector wells). The increase in overall well count from the base depletion plan is in response to development learnings from Hebron pools 1, 2, 4H, 4B and 5 and is considered normal optimization in good oil field management. The final well count for the JDA DPA is subject to change over time as the well schedule will be paced to allow time for new reservoir learnings to be incorporated into each subsequent well.

The displacement strategy for the JDA Formation sands includes secondary recovery by waterflood. The existing secondary recovery mechanism of water displacement will be maintained however, other development strategies may be tested to optimize reservoir performance as new information becomes available. The proposed depletion plan is anticipated to recover approximately 7 Mm3 or 43 MBO from the JDA Formation sands from six additional wells utilizing existing facilities. While offsetting natural decline in production, the additional JDA Formation wells will not materially impact volumes throughput or emissions associated with the Hebron Development and remains within the range of estimates in the original comprehensive study report (CSR) and subsequent Environmental Assessment (EA) submissions.

Currently, gas produced from the development at Hebron is injected into the Ben Nevis Formation at Pool 2, and in the I-13 Block as part of a water-alternating gas strategy. The revised Hebron depletion plan (2020) also considers future optionality for injection into the crest of the Horst Block. Over the life of the field, gas production is expected to average 3.6 Msm3/d, with 0.6 Msm3/d for operational, 3.0 Msm3/d for gas injection and 2.1 Msm3/d for gas lift. ExxonMobil will continue to evaluate opportunities to develop the Hebron gas resource, however; the current plan is to use gas in support of oil recovery. Produced gas will continue to provide primary power to the Hebron Platform.

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Acronyms

ADW	Approval to Drill Well
AI	Acoustic Impedance
APB	Annular Pressure Buildup
API	American Petroleum Institute
APSDM	Anisotropic Post Stack Depth Migration
ASV	Annular Safety Valve
A_y	Acceleration in y
A_z	Acceleration in z
BOP	Blow out Preventer
CDA	Commercial Discovery Area
C-NLOPB	Canada Newfoundland and Labrador Offshore Petroleum Board
cp	Centipoise
CPOR_OB	Core Porosity at Overburden
cp	centipoise
CRI	Cuttings Reinjection
CSR	Comprehensive Study Report
DegC	Degrees Celsius
DEGC	Degrees Celcius
DHCI	Downhole Chemical Injection
DHTG	Downhole Temperature Gauge
DP	Development Plan
DPA	Development Plan Amendment
DRES	Deep Resistivity
DRHO	Density Correction
DSR	Deconvolution Spectral Reshaping
DST	Drillstem Test
DT	Delta Time
Dv	Deviated Well
EA	Environmental Assessment
EMCP	ExxonMobil Canada Properties
EOD	Environment of Deposition
EUR	Expected Ultimate Recovery
FB	Fault Block
FDAP	Field Data Acquisition Plan
FWL	Free Water Level
GBS	Gravity Based Structure
GL	Gas Lift
GLM	Gas Lift Mandrel
GR	Gamma Ray
Hor/Hz	Horizontal Well
Hz	Hertz
ICV	Inflow Control Valve
IWC	Intelligent Well Control
JDA	Jeanne d'Arc Formation
K	Permeability
KAIR_OB	Air permeability at overburden
Kbd	Thousand barrels/Day
Kg/m^3	Kilograms per metre cubed
Kh	Horizontal Permeability
Kair	Permeability air
Km	Kilometre
Km^2	Kilometres squared
Km^3	Kilometres cubed
Km3/day	Kilometres cubed/day
KPa	KiloPascals
KPa/m	KiloPascals per metre
KSI	Pounds per square inch
Kv	Vertical Permeability
m	Metre
m^3	Metres cubed
MB	Million Barrels
MBAL	Material Balance
MBO	Million Barrels Oil
m^3/d	Metres cubed/day
mD	MilliDarcy
mD-m	MilliDarcy/Metre
MD	Measured Depth
MD RT	Measured Depth Rotary Table
mg/L	Milligram/Litre
ML	Multi-lateral
m^3/m^3	Volume Ratio
Mm^3	Million cubic metres
mm	Millimetre
Mm^3	Million Metres cubed
Mm^3/d	Million metres cubed/day
m MD	Metres Measured Depth
MPa	MegaPascals
Mscf/d	Million standard cubic feet/day
Msm3/d	Million standard cubic metres/day
m TVD	Metres True Vertical Depth
mTVDss	metres True Vertical Depth subsea
NAF	Non-aqueous Fluid
NPHI	Neutron Porosity
NMR	Nuclear Magnetic Resonance
NV	North Valley
^oC	Degrees Celsius
OIP	Oil in Place
OP	Oil Producer
OWC	Oil Water Contact
ODT	Oil Down To
OUT	Oil Up To
P	Pressure
P1	Pool 1 Ben Nevis Formation Hydrocarbon Accumulation
P2	Pool 2 Ben Nevis Formation Hydrocarbon Accumulation

P4B	Pool 4 B Sand Jeanne d'Arc Formation Hydrocarbon Accumulation
P4C	Pool 4 C Sand Jeanne d'Arc Formation Hydrocarbon Accumulation
P4E/D	Pool 4 E/D Sand Jeanne d'Arc Formation Hydrocarbon Accumulation
P4F	Pool 4 F Sand Jeanne d'Arc Formation Hydrocarbon Accumulation
P4G	Pool 4 G Sand Jeanne d'Arc Formation Hydrocarbon Accumulation
P4H	Pool 4 H Sand Jeanne d'Arc Formation Hydrocarbon Accumulation
P5	Pool 5 Hibernia Formation Hydrocarbon Accumulation
Pc	Capillary Pressure
Phi	Porosity
PHIT	Total Porosity
PHTIshl	Total Porosity of Shale
Phi_ambient	Porosity ambient
Phi_ob	Porosity overburden corrected
PHITshl	Shale Porosity
Perm	Permeability
Perm_ambient	Permeability ambient
Perm_ob	Permeability overburden corrected
PL	Production License
Pool 1-D	Pool 1, D-94 Block
Pool 1-I	Pool 1, I-13 Block
Ppm	Parts Per Million
PSI	Pounds per square inch
PTA	Pressure Transient Analysis
PVT	Pressure Volume Temperature
Q	Attenuation
RCAL	Routine Core Analysis
RES	Resistivity
RF	Recovery Factor
RHOB	Bulk Density
RHOFL	Fluid Density
RHOG	Grain Density
RHOshl	Shale Density
RHOFL	Fluid Density
RHOG	Grain Density
RHOshl	Shale Bulk Density
RKB	Rotary Kelly Bushing
Rm^3/Sm^3	Ratio reservoir volume to surface volume
RSWC	Rotary Sidewall Core
SCAL	Special Core Analysis
SDL	Significant Discovery License
SEG	Society of Exploration Geophysicists
SRES	Shallow Resistivity
SSTVD/TVDSS	Subsea True Vertical Depth
STOOIP	Stock Tank Oil Originally In Place
SV	South Valley
Sw	Water Saturation
SWG	Southwest Graben
Swirr	Irreducible Water Saturation
SWT	Water Saturation Total
TRSCSSV	Tubing Retrievable Surface-controlled Subsurface Safety Valves
TTI	Tilted Transverse Isotropy
TVD	True Vertical Depth
TVDRT	True Vertical Depth Rotary Table
TVDss/ssTVD	True Vertical Depth subsea
TWTT	Two Way Travel Time
Vert	Vertical Well
Vp/Vs	Velocity Ratio
VSH	Volume of Shale
V/V	Volume/Volume
WAG	Water Alternating Gas
WI	Water Injector
XRD	X Ray Diffraction
XT	Christmas Tree

1 Overview

ExxonMobil Canada Properties ("ExxonMobil"), as operator of the Hebron Project, is submitting this DPA on behalf of itself and the other Hebron co-venturers, Chevron Canada Limited, Suncor Energy Inc., Equinor Canada Limited, and Nalcor Energy – Oil and Gas Inc.

The Development Plan provides for development of Jeanne d'Arc Formation H and B Sands. The purpose of this document is to seek approval for development of remaining sands within the Hebron JDA Formation. The planned production from this interval will utilize existing Hebron workforce and facilities and is within the capacity limits of the Hebron Platform which contemplated future resource additions.

1.1 Hebron Jeanne d'Arc Formation Project Area

This DPA covers the JDA Formation within the collection of fields (Hebron, West Ben Nevis and Ben Nevis) referred to throughout the DPA as the "Hebron Asset". The Hebron Asset is located on the Grand Banks, approximately 340 km offshore St. John's, Newfoundland and Labrador, and approximately 9 km north of Terra Nova, 32 km southeast of Hibernia and 46km southwest of White Rose (Figure 1-1). The water depth ranges from 88 to 102 m.

Production from Hebron is from PL 1012 and includes Ben Nevis, Hibernia, and Jeanne d'Arc (JDA) formations. Hydrocarbon accumulations within the JDA Formation may extend to production licenses 1003 and 1004. The Commercial Discovery Area (CDA) includes the relevant sections in SDL 1006, SDL 1046, SDL 1042, PL 1003, and PL 1004 (Figure 1-2).

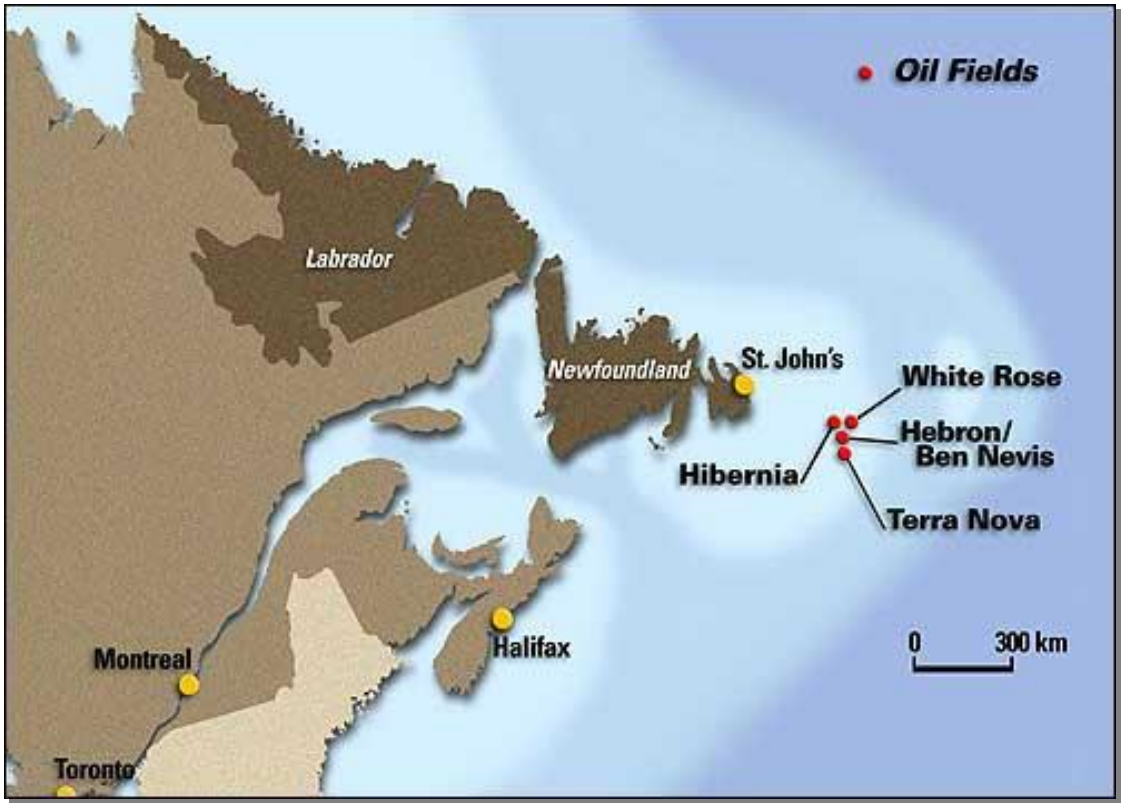


Figure 1-1 Hebron Asset location

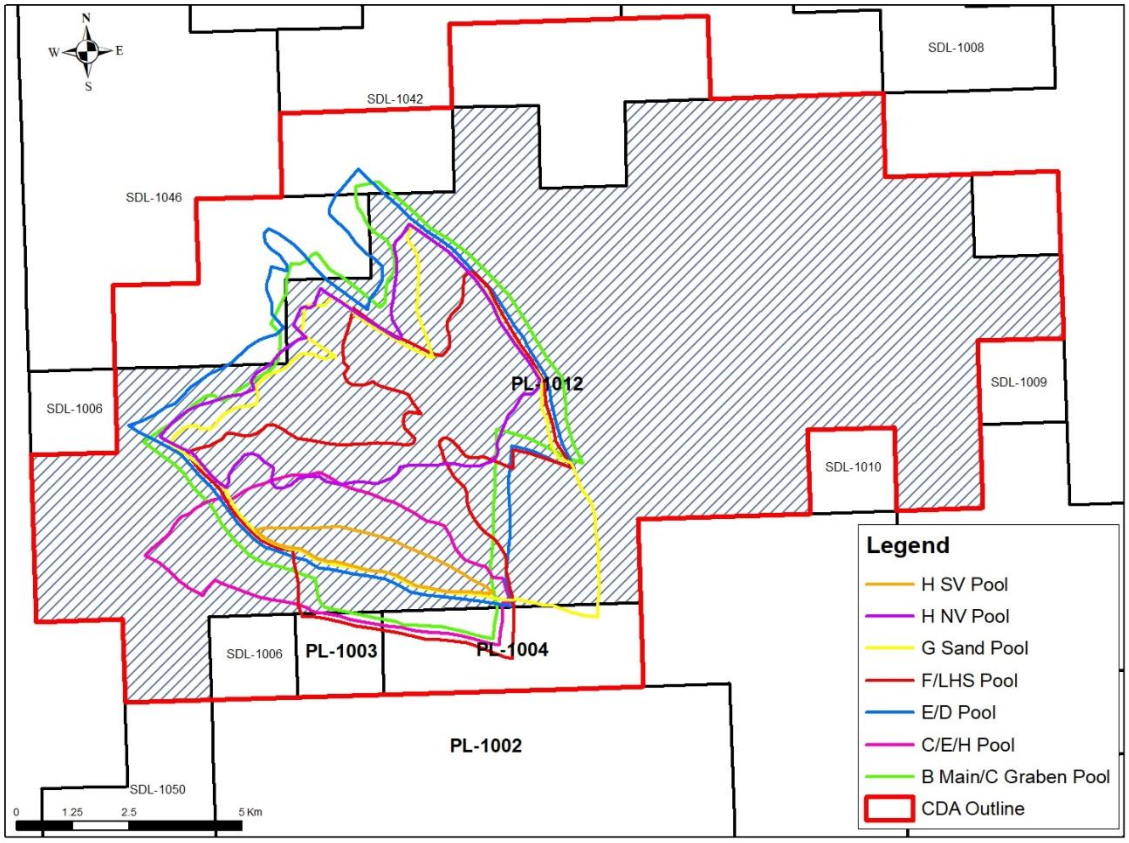


Figure 1-2 Hebron Asset license boundaries and proposed Jeanne d'Arc Formation individual sand pool outlines.

1.2 Project Proponents

The Hebron Project co-venturers and their respective working interests are as follows:

- ExxonMobil Canada Ltd. (35.4552113%)
- Chevron Canada Limited (29.5960411%)
- Suncor Energy Inc. (21.0341233%)
- Equinor Canada Ltd. (9.0146243%)
- Nalcor Energy – Oil and Gas Inc. (4.9%)

1.3 Project Need and Justification

Recent production and delineation drilling at Hebron has reduced uncertainty associated with the JDA Formation sands, including the H and B sands which are part of the Development Plan. The optimized development of the JDA Formation and the capture of additional resource 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 area resources consistent with good oil field practice.

1.4 Scope of the Project

This DPA covers sands previously included as contingent resources in the Development Plan plus newly delineated resources and in a success case, is projected to add up to 43.2 MBO to the Hebron development. The DPA includes all sands within the JDA Formation between the H and B sands and extends across the Hebron Horst Block and the surrounding fault blocks to the east and south.

1.5 Proposed Development Schedule

The wells from this DPA are embedded in the Hebron drill schedule (Figure 1-3). This drill schedule projects a total well count of 51 (including 1 CRI) which is within the Hebron platform design of 52 well slots. Additional development potential is under evaluation, including future appraisal opportunities which would target areas of undiscovered or uncertain potential. In a success case, additional development could be possible so strategic use of well slots is considered with every drill well opportunity. Existing technologies such as slot reclaims, and multi-lateral completions may be used to optimize future slot utility while maximizing targets.

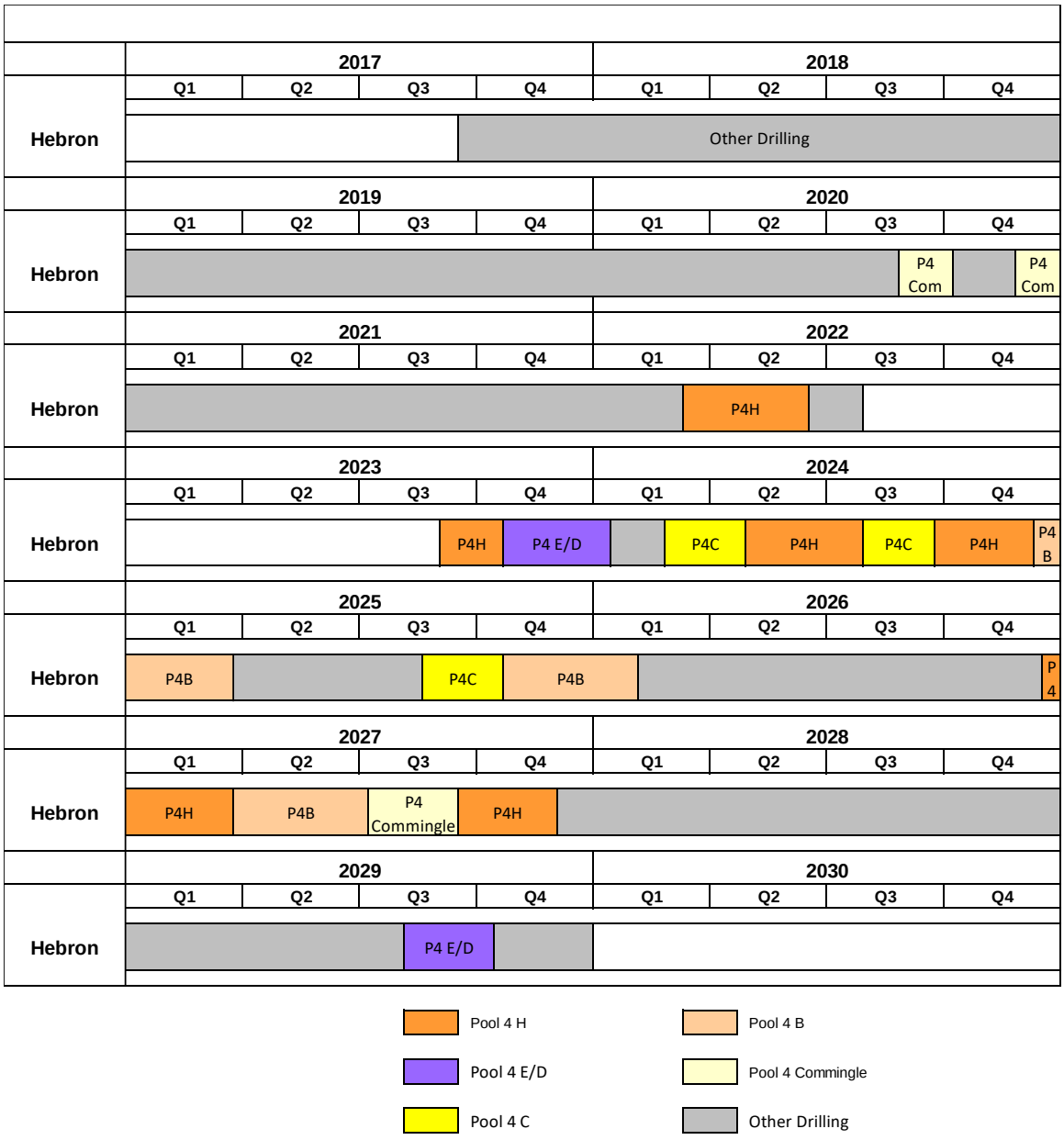


Figure 1-3: Hebron Integrated Drill Schedule, 2022 Outlook

No additional work scope beyond the drilling of wells will result from this DPA.

1.6 Environmental Assessment Review

The Hebron Project was subject to a detailed and comprehensive Environmental Assessment (EA) review, culminating in a comprehensive study report (CSR), pursuant to the requirements of the *Canadian Environmental Assessment Act*. In December 2011 the federal Minister of the Environment issued an EA Decision Statement, stating that "the Project, taking into account the mitigation measures described in the Comprehensive Study Report, is not likely to cause significant adverse environmental effects; and the mitigation measures and follow-up program described in the Comprehensive Study Report are appropriate for the proposed Project."

ExxonMobil has submitted a CSR Addendum (2013), periodic EA Updates and two EA Amendments (2017 and 2018). These documents provide an overview of planned Project activities, particularly those applicable to the Project's environmental aspects. The nature and scope of updated planned drilling activities associated with this JDA DPA are in keeping with the scope of the Project as described, assessed, and approved under the EA process outlined above.

The CSR and subsequent amendment (2017) modeled and assessed the discharged cuttings based on 52 wells drilled sequentially. This JDA DPA is anticipating a total of 51 wells which is within the boundaries of those assessments. The additional wells indicated in this DPA will not materially impact the expected discharges or emissions as outlined in the CSR and subsequent EA submissions.

The expected volumes throughput with this incremental development is within the range of rates assessed in the CSR, utilizing existing facilities. Specific to environmental factors, as shown in Figure 1-4 and Figure 1-5, produced water discharge rates and greenhouse gas emissions are estimated to remain within ranges anticipated in the CSR.

Furthermore, each environmental issue / effect and associated mitigations measures (as reflected in the CSR and subsequent EA submissions) remains applicable to the nature and scope of the updated planned Project activities. The mitigations will be implemented in accordance with ExxonMobil's commitments and obligations pursuant to the Project's EA approval, and other applicable legislative and regulatory requirements. In addition, Hebron has in place follow-up monitoring procedures on the platform (Environmental Compliance Monitoring Program) and in the receiving environment (Environmental Effects Monitoring Program) to ensure the Project (including the activities described in this DPA) remains within the predictions of the CSR.

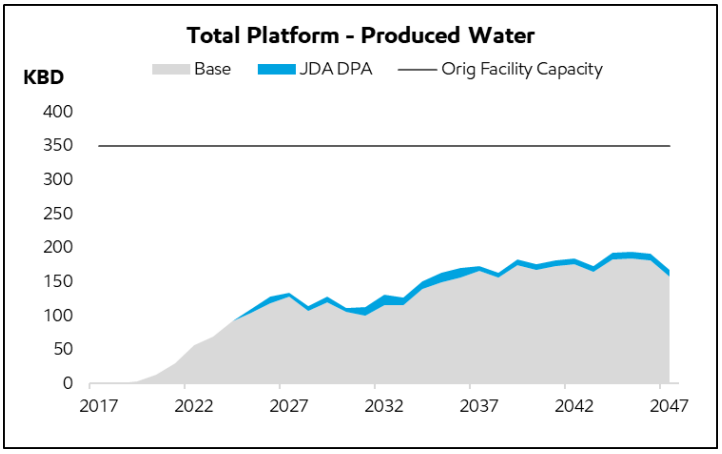


Figure 1-4: Projected range of produced water rates for Hebron Project

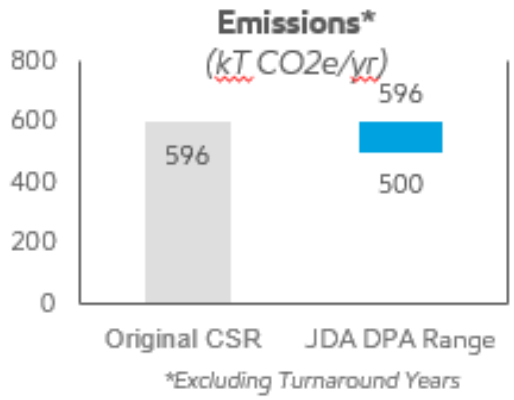


Figure 1-5: Projected range of Hebron greenhouse gas emissions.

1.7 Industrial Benefits

The *Canada-Newfoundland Atlantic Accord Implementation Act* and the *Canada-Newfoundland and Labrador Atlantic Accord Implementation Newfoundland and Labrador Act* (the Accord Acts) require that a Benefits Plan be approved by the C-NLOPB prior to authorization of any offshore work or activity.

The April 2011 Hebron Project Canada-Newfoundland and Labrador Benefits Plan was approved by the C-NLOPB in April 2012 (the Hebron Benefits Plan). The Hebron Benefits Plan aims to further advance the development of the industry in the Province so that Hebron delivers long term value to Newfoundlanders and Labradorians and other Canadians.

This DPA seeks approval to develop the remaining sands within the Hebron JDA Formation. Development of these sands will assist in offsetting the natural decline in production at Hebron and is the next step to optimizing Hebron area resources consistent with good oil field practice.

The development of these sands will utilize the existing Hebron workforce and facilities, including existing production, drilling and wellwork equipment and is within the capacity limits of the Hebron Platform which contemplated future resource additions.

The Hebron Benefits Plan was approved by the C-NLOPB and addresses the requirements set out in the Accord Acts. In consultations before filing this DPA, the Board determined that a Benefits Plan Supplement would be appropriate for the DPA activities. As a result, the Hebron Benefits Plan will apply to this DPA and reflects a continuing obligation for the activities described in this DPA.

ExxonMobil will continue to ensure that companies in the Province and other parts of Canada have a full and fair opportunity to compete for Hebron work, and that first consideration is given to goods manufactured in, and services provided from within, the Province where they are competitive in terms of fair market price, quality and delivery. Consistent with the Canadian Charter of Rights and Freedoms, residents of Newfoundland and Labrador will continue to be given first consideration for employment opportunities.

ExxonMobil is fully committed to following the Hebron Benefits Plan throughout the execution of the activities outlined in this DPA.

2 Geology, Geophysics and Petrophysics

The Hebron Asset is located in the east central part of the Jeanne d'Arc Basin (Figure 2-1). Oil was initially discovered in the Hebron Asset area in 1980 with the Ben Nevis I-45 well. This well tested uneconomic rates of oil in the Ben Nevis Formation and gas/condensate in the A Marker and Lower Hibernia Formation. The initial I-45 discovery was followed by two phases of delineation drilling. The first phase in the early 1980's included the Hebron I-13 well drilled in 1981 targeting the highest structure of the Hibernia and Jeanne d'Arc formations and tested oil in both. It also encountered oil in the Ben Nevis Formation. In 1985, the West Ben Nevis B-75 well was drilled between I-45 and I-13 and tested oil in the Ben Nevis and Avalon formations. Also in 1985, the North Trinity H-71 well was drilled on the east flank of the structure but found no significant amounts of hydrocarbons.

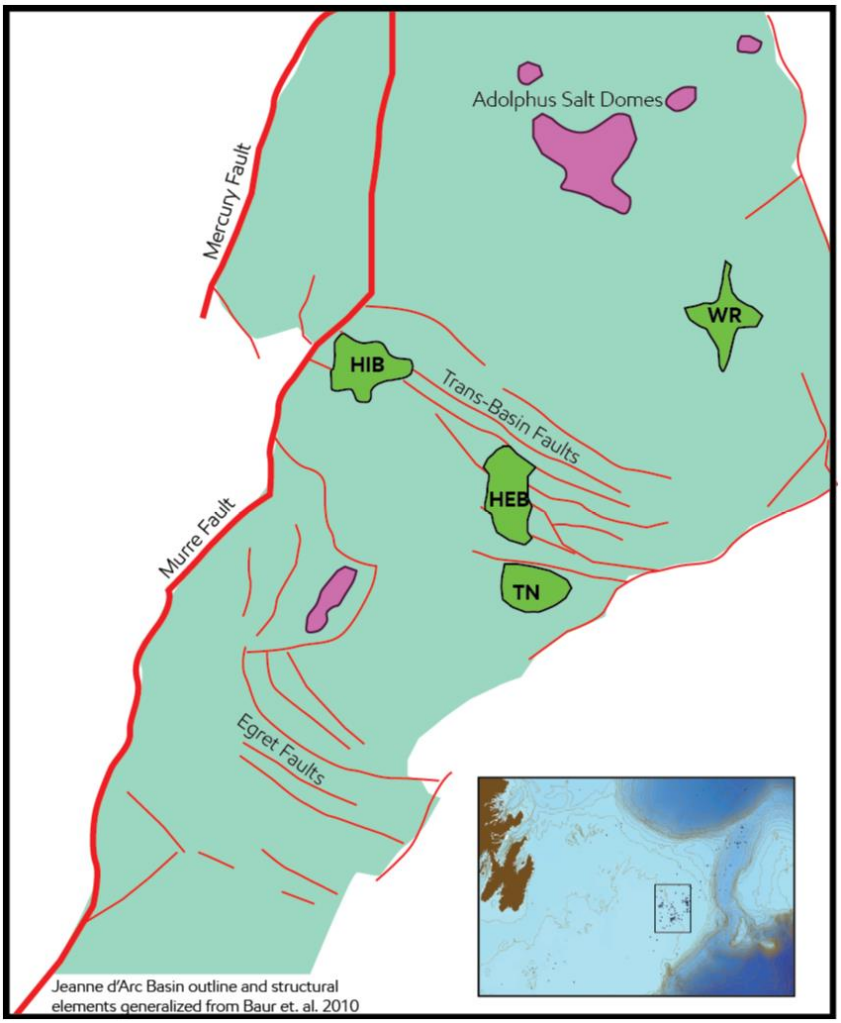


Figure 2-1: Generalized Jeanne d'Arc Basin (green fill) and structural elements. Locations of Hibernia (HIB), Hebron (HEB), Terra Nova (TN) and Whiterose (WR) producing assets shown. Modified from Baur et al. 2010.

A second phase of drilling began with the D-94 well in 1999 to further test the Ben Nevis Formation encountered in the I-13 well. The Ben Nevis L-55 well was drilled in 1999 updip of the Ben Nevis I-45 well and encountered gas. The M-04 well was drilled in 2000 to gather additional data on the existing Ben Nevis, Hibernia and Jeanne d'Arc formations.

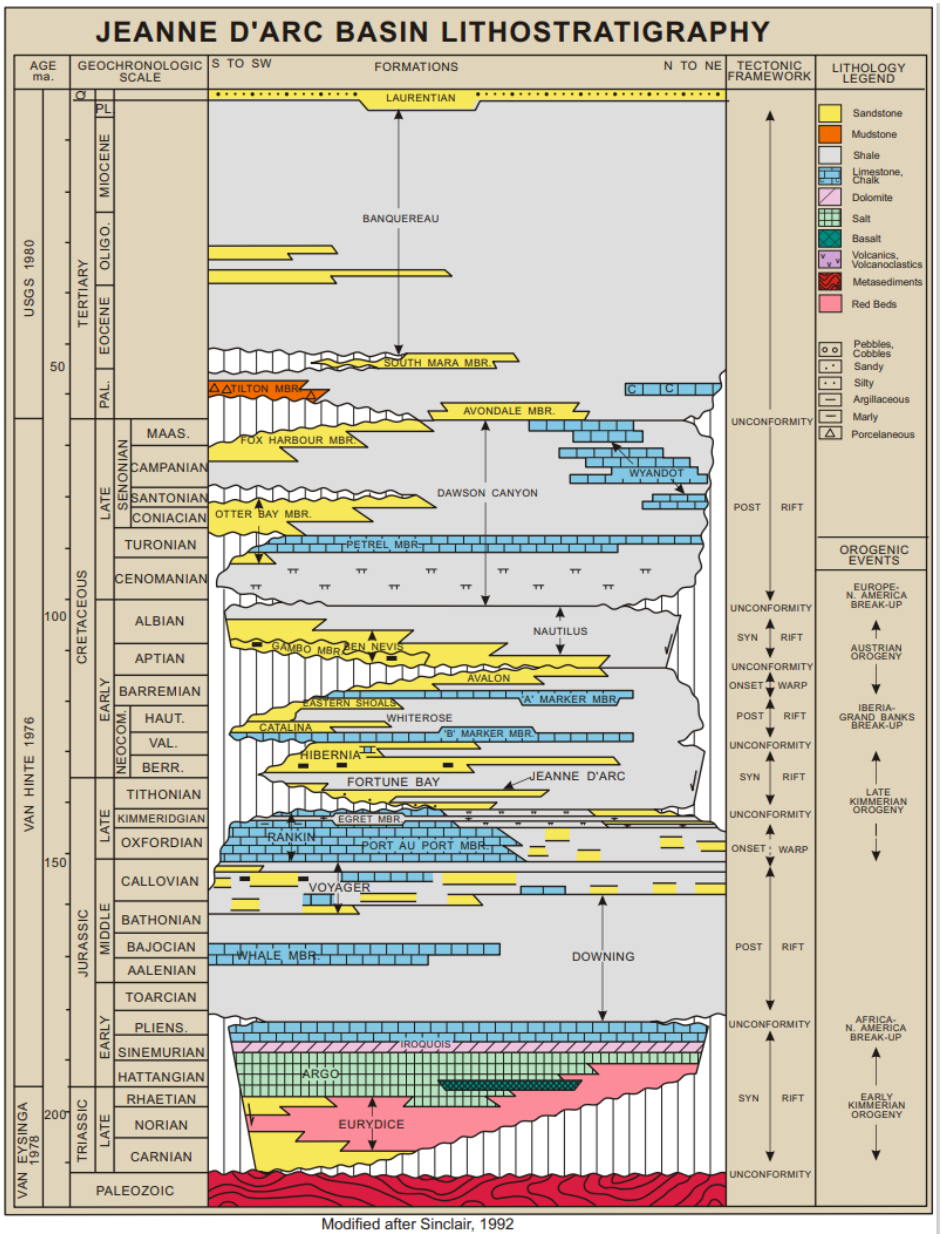
Initial production at the Hebron Asset area, targeted the Ben Nevis Formation with more recent drilling focused on the Hibernia and Jeanne d'Arc formations. The sections that follow will discuss the geology, geophysics and petrophysics of the JDA Formation as the focus of this DPA. The material discussed within this document will be in addition to that presented in the Hebron Development Plan (2011) and subsequent Hebron Depletion Plan Revision Reports (2015, 2020).

2.1 Geology

Section 2.1 will focus on geology, starting first with the Hebron Asset area geology and including a brief description of the stratigraphic sequence and fault blocks (Section 2.1.1). Section 2.1.2 will focus on the Jeanne d'Arc Formation specifically including the stratigraphy (Section 2.1.2.1) and structural geology (Section 2.1.2.2).

2.1.1 Hebron Asset Area Geology

The oldest rocks penetrated in the Hebron Asset area are Late Jurassic (Early Kimmeridgian) marine limestones, marlstones, shales, and siltstones of the Rankin Formation (Figure 2-2). The uppermost part of this succession, which ranges in age from Late Callovian to Kimmeridgian, was encountered in the basal portion of the I-13 exploration well. The Egret member (Kimmeridgian) source rocks occur near the top of the Rankin Formation. The source rocks are regionally extensive and consist of thinly interbedded limestone, marlstone and calcareous shale, deposited in a low-energy, restricted-marine environment.



Modified after Sinclair, 1992

Figure 2-2: Jeanne d'Arc Basin lithostratigraphy. From C-NLOPB

Unconformably overlying the Rankin Formation is the Jeanne d'Arc Formation. This is the deepest reservoir at Hebron and represents the beginning of a second rifting episode within the basin. It is a basinward (northward) thickening clastic sequence comprised of multiple fine to coarse grained sandstones with minor interbedded limestones segregated vertically by shale, mudstone, and siltstone. To the north, the sequence grades to predominantly marine shales.

Overlying the Jeanne d'Arc Formation is the Fortune Bay Formation, a thick succession of offshore shales and siltstones. This is in turn overlain by the Hibernia Formation. The lowermost section of the Hibernia Formation is equivalent to the producing reservoir at Hibernia Field. The uppermost Hibernia Formation is a secondary reservoir at Hebron comprised of shoreface sandstone successions and minor marginal marine deposits. A widespread oolitic limestone, the B Marker, was deposited in a marine transgression on top of the Hibernia Formation. This is followed by the interbedded calcareous limestones and sandstones of the Catalina Formation and the shales, minor sandstones, siltstones, and limestone beds of the Whiterose Formation.

The Avalon Formation, a stacked succession of marine to marginal marine calcareous sandstones, bioclastic limestone, and minor shales, overlies the Whiterose Formation. The bottommost portion of this formation is designated as the “A Marker”. The Avalon Formation is overlain by the Ben Nevis Formation which is the primary reservoir at Hebron and is a succession of coarsening upward shoreface parasequences bounded by flooding surfaces.

The Nautilus Formation conformably overlies the Ben Nevis Formation and is comprised of grey siltstones and shales with minor sandstone. The Dawson Canyon Formation unconformably overlies the Nautilus Formation and is composed of marls and calcareous shales. Near the top, it includes the Petrel Member, a light grey to brown argillaceous limestone.

The Banquereau Formation overlies the Nautilus Formation and is composed of Tertiary clastics deposited during thermal subsidence. It is a thick shale succession with coarser clastics locally encountered near the base.

With the primary reservoir of the Hebron Asset being the Ben Nevis Formation, structural divisions of the asset are based on a structure map of that reservoir. The Hebron Asset is divided into five major fault blocks (Figure 2-3):

a. Hebron Southwest Graben (penetrated by L-93 31)
b. Hebron I-13 Fault Block (penetrated by I-13 well plus multiple development wells)
c. Hebron Horst (penetrated by D-94 and M-04 wells plus multiple production wells; I-13 well crosses the fault and delineates the Horst block at depth)
d. West Ben Nevis (penetrated by B-75 and L-93 06)
e. Ben Nevis (penetrated by L-55 and I-45 exploration wells)

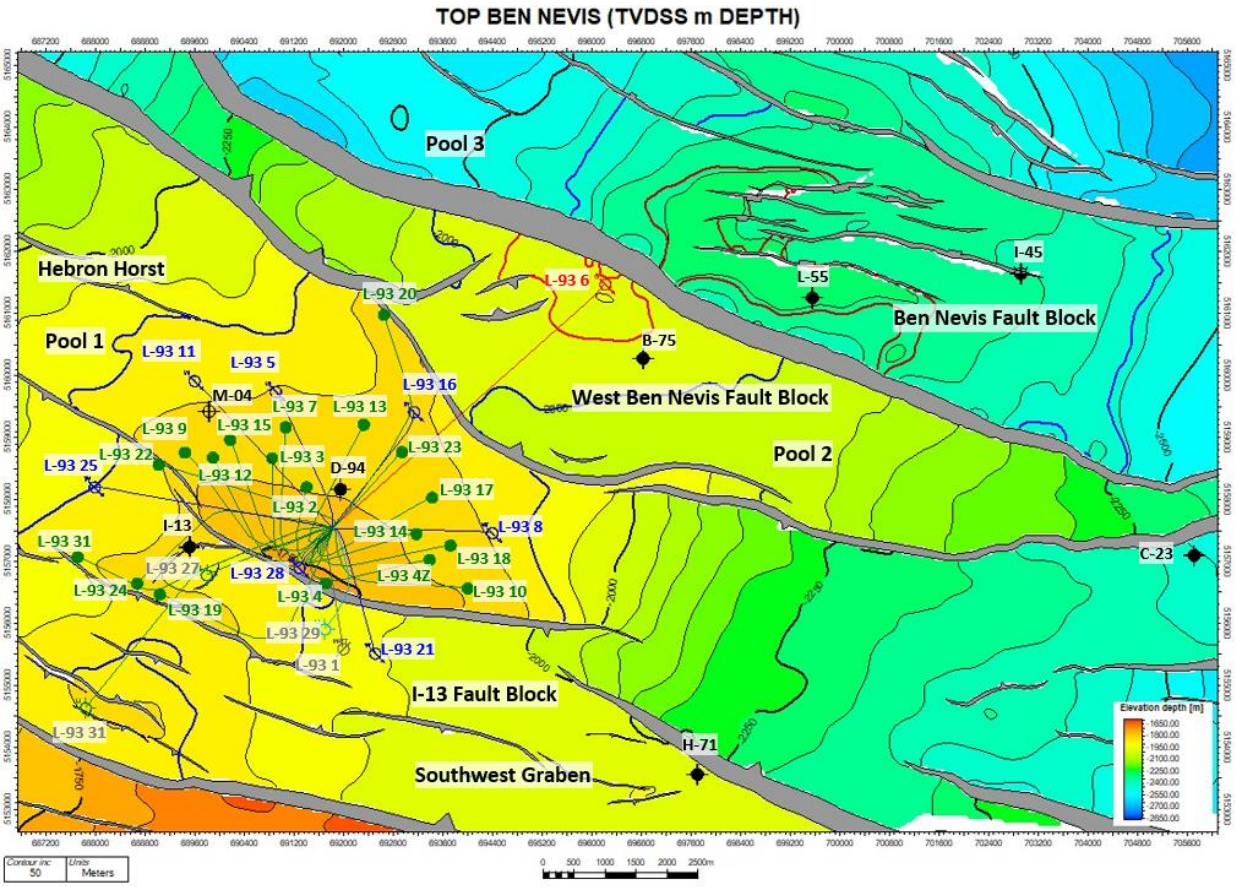


Figure 2-3 Structure map, top Ben Nevis Formation, showing Hebron Asset fault blocks

Overall, the Hebron Asset area is part of the north-south trending and north plunging Terra Nova anticline. The anticline is transected by the northwest-southeast trending “trans-basin” fault trend. The northwest-southeast faults bound the Horst block which is the highest structural feature in the Hebron Asset area. Collectively, the Hebron Horst block and the I-13 fault block have been referred to as the Hebron Field.

The West Ben Nevis and the Ben Nevis fault blocks are down-dropped to the northeast. These fault blocks are often referred to as Pool 2 and Pool 3, respectively, when discussing the hydrocarbon accumulation in the Ben Nevis reservoir. They have also been referenced as the West Ben Nevis and Ben Nevis fields.

North-to south striking normal faults, active during an extensional event in the Late Jurassic to Early Cretaceous are observed in intervals beneath the Ben Nevis Formation. These faults mostly offset the Jeanne d’Arc Formation but a few also offset the Hibernia Reservoir. The schematic below (Figure 2-4) shows the relationship between the different Hebron pools and fault blocks and the decrease in intensity of faulting in the shallower section.

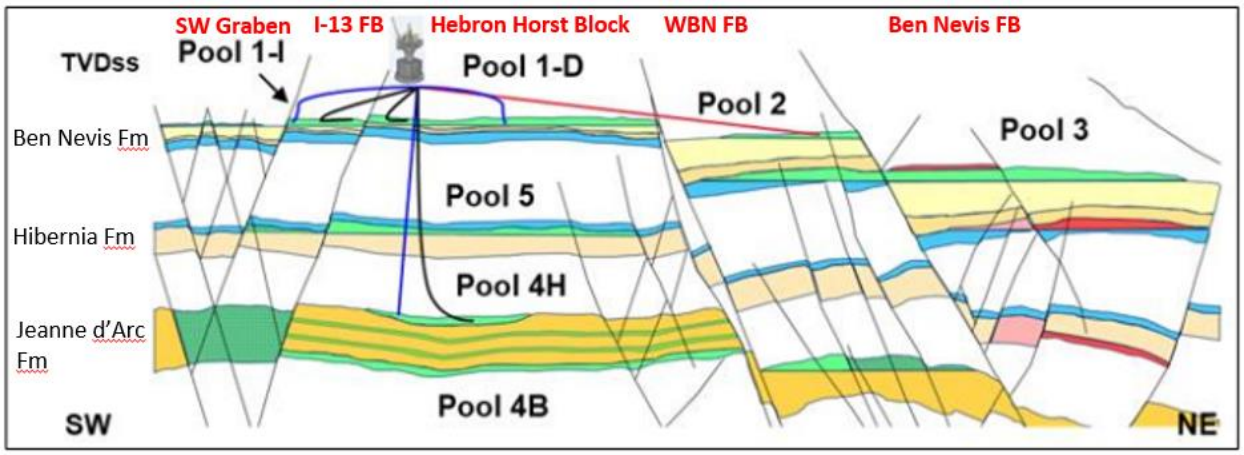


Figure 2-4: Schematic cross section of the Hebron Asset are reservoirs, fault blocks and pools.

At the level of the Jeanne d'Arc Formation, the increased faulting results in additional fault blocks rimming the eastern and southern parts of the Hebron Horst block (Figure 2-5). These fault blocks have been labelled clockwise as A', B', C', D', E', and F'.

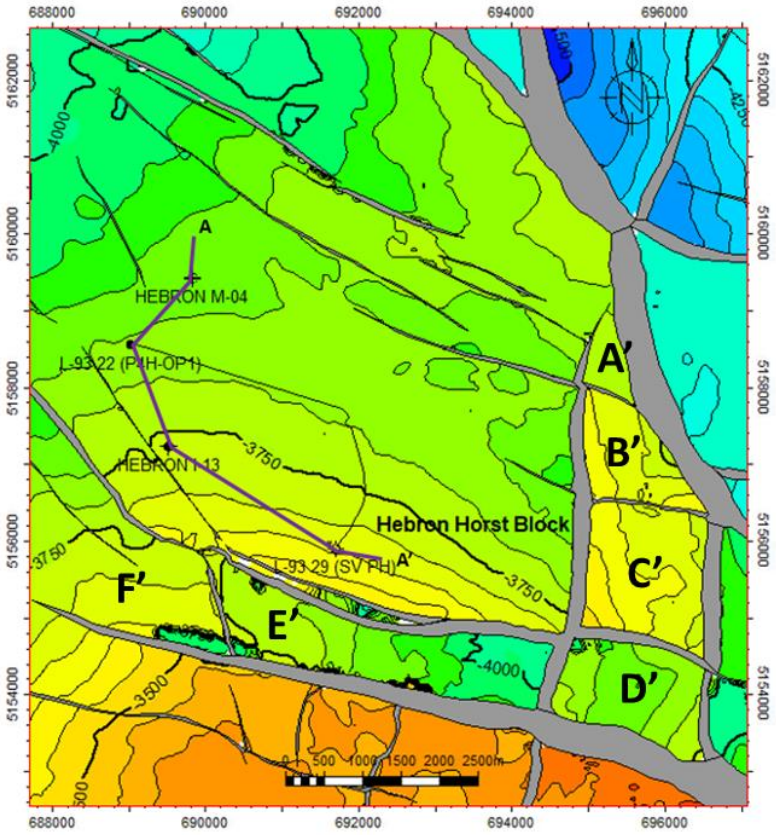


Figure 2-5: Structure map, top Jeanne d' Arc Formation, shows additional mapped faults (grey filled polygons) and fault blocks.

2.1.2 Jeanne d'Arc Formation Reservoir Geology

The Jeanne d'Arc Formation was deposited during the Kimmeridgian to Tithonian and is the deepest producing reservoir within the Hebron Asset area. It unconformably overlies the Rankin Formation and

represents the beginning of a second phase of rifting during the Late Jurassic. It is in turn overlain by the offshore marine shales and siltstones of the Fortune Bay Formation.

Biostratigraphic data from four wells (I-30, I-13, M-04 and B-75) constrain the Jeanne d'Arc Formation to Kimmeridgian to Tithonian in age. The biostratigraphy is not at a high enough resolution for detailed log correlations but has been used to constrain the formation age.

Overall, the Jeanne d'Arc Formation is a basinward (northward) thickening clastic wedge with sediment provenance from the Avalon High to the south. The reservoir sands transition basinward into marine shales. South of the Hebron Asset area, it is the oil bearing and producing reservoir at the Terra Nova Field where it onlaps the Rankin Formation. At Terra Nova, the reservoir has a higher net to gross, is coarser grained, and is more proximal in the depositional system.

At Hebron, there are several sand intervals with variability in thickness and reservoir development which will be described in Section 2.1.2.1. Based on a 1mD cutoff, the porosity and permeability of the net ranges from 5-15% and 5-800 mD, respectively. The sands within the Jeanne d'Arc Formation were primarily deposited in a fluvial environment of deposition which lends itself to more discontinuity in reservoir deposition. Variable degrees of cementation have also been observed with increased cementation noted in the deepest sand where the inclusion of Rankin Formation carbonate rich clastics in the fluvial deposits may form a source for cementation.

2.1.2.1 Jeanne d'Arc Formation Stratigraphy

The Jeanne d'Arc Formation is interpreted as a thick succession (up to 650m) containing multiple fine to coarse-grained sandstones with minor interbedded limestones, segregated vertically by siltstone, shale, and mudstone. Several sequences are identified and are composed of stacked fluvial channel sands topped by shale. The depositional facies range from fluvial to estuarine. The most significant sand intervals are labelled from top to bottom as H, G, F, E/D, C, BC Stringers, and B sands. A cross section of the Hebron Horst Block wells (Figure 2-6) shows the stratigraphic position and correlation of the various sand units. Sand units are named alphabetically from bottom to top.

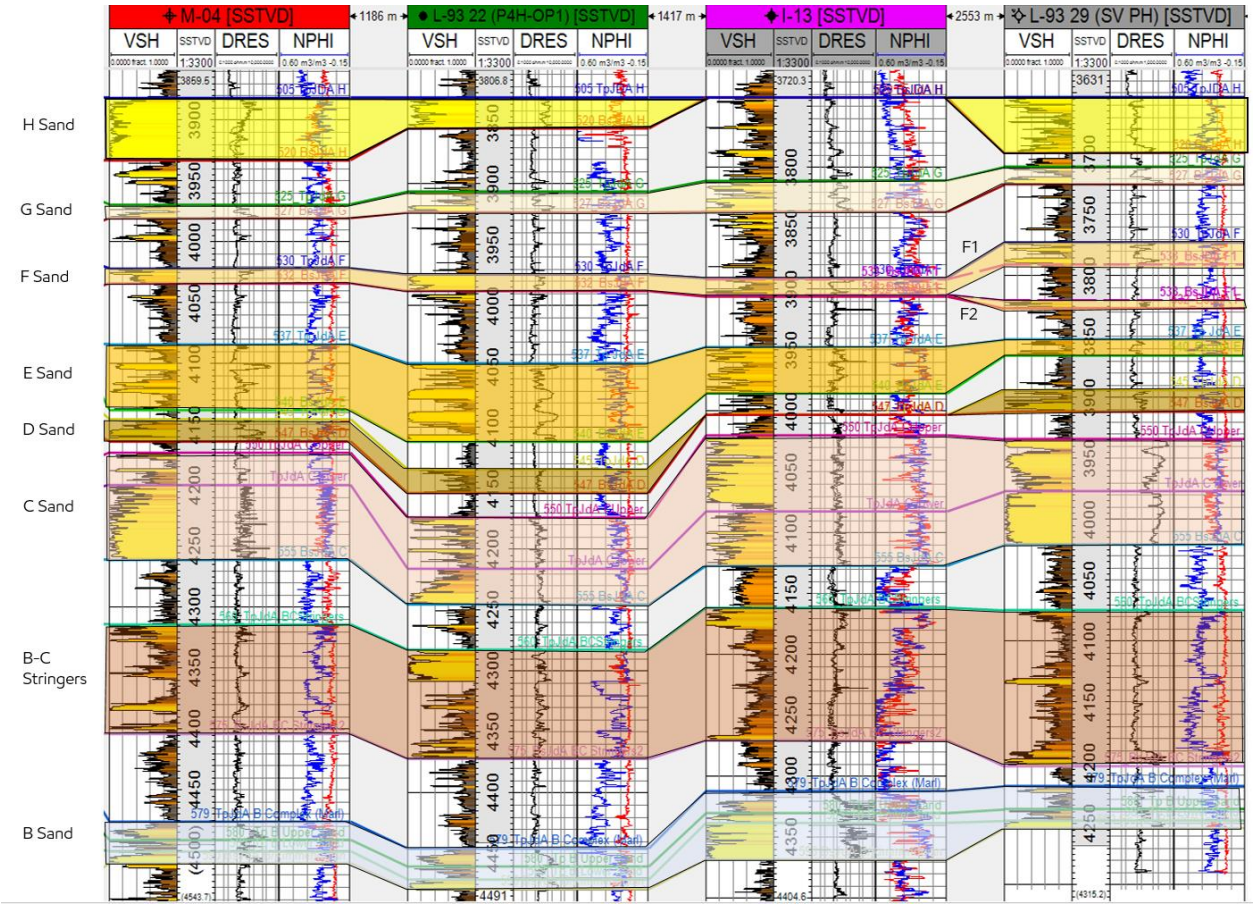


Figure 2-6: Well cross section showing the available Jeanne d'Arc Formation wells in the Hebron Horst block, and stratigraphic correlation between the sands. Well locations and line of section (purple line) shown in Figure 2-5

Correlation of individual sand units across the entire area can be challenging as the environment of deposition (EOD) is fluvial and stratigraphic edges are anticipated. Sand packages are correlated based on stratigraphic position, well log motif, seismic mapping, and pressure observations. Seismic mapping of individual sand units can be difficult when sand packages are below seismic resolution coupled with the similar seismic response for both sandstone and siltstone.

2.1.2.1.1 H Sand

Well tops and correlations presented in Figure 2-6 represent a high-level lithologic correlation and further subdivision is possible. Additional subdivision of the H Sand is based on interpretation of the data. The H Sand is the topmost sand penetrated in the Jeanne d'Arc Formation, but it can be subdivided into a North and South Valley braided fluvial valley depositional system based on mapped seismic amplitudes augmented by well observations (Figure 2-7). These valley systems may or may not be contemporaneous. To distinguish between the two H sand valley-systems, the sands can be referred to as H Sand – North Valley (NV) or H Sand – South Valley (SV).

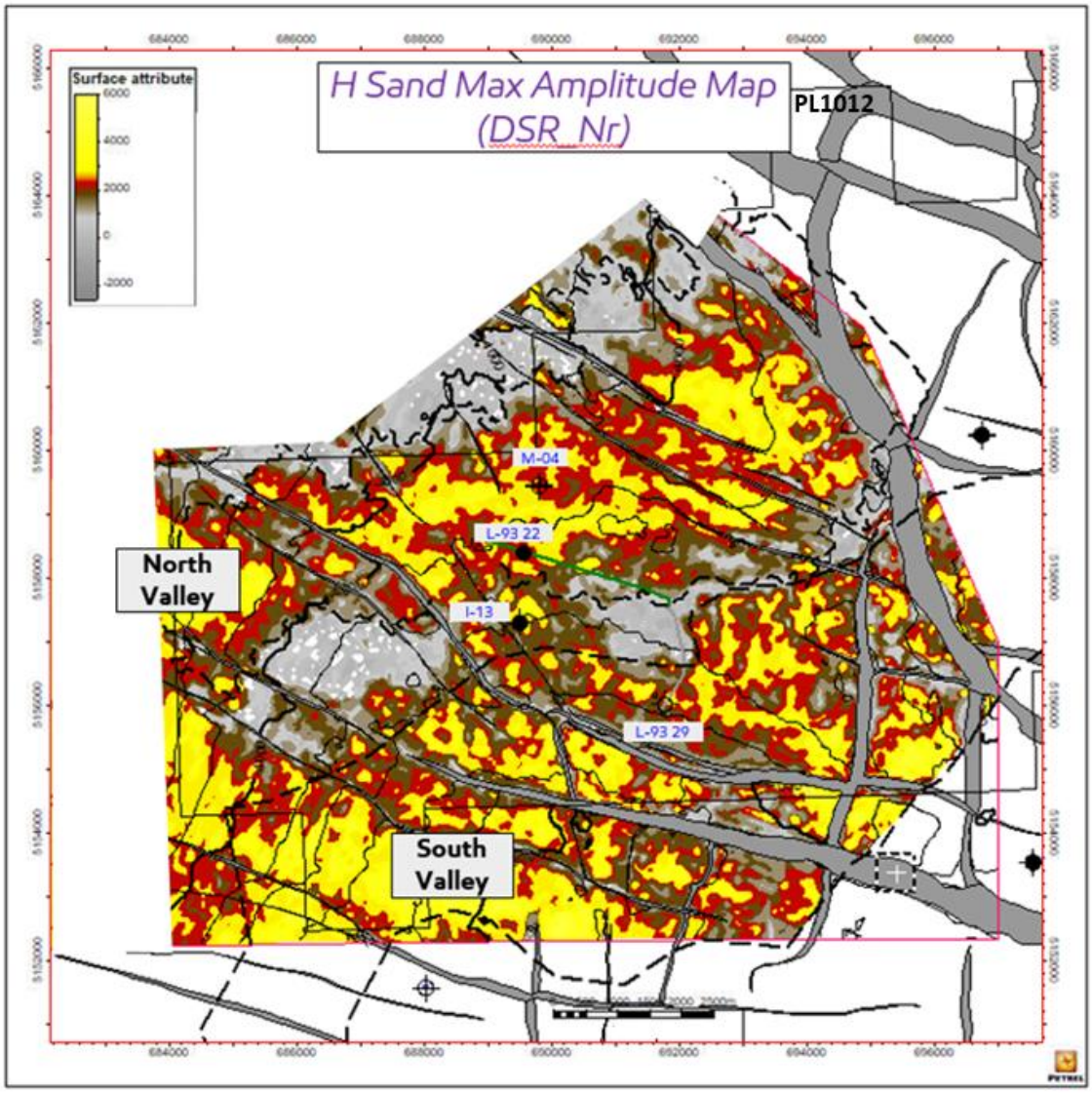


Figure 2-7: Map of DSR amplitude for top H Sand. Structure contours from top H Sand surface. Two valley systems are suggested by the amplitude data and are named North Valley (penetrated by M-04 and L-93 22) and South Valley (penetrated by L-93 29). I-13 is located between the valleys and did not encounter sand.

An Environment of Deposition (EOD) map for the H Sand is shown below (Figure 2-8). The orientation and width of the valley systems are based primarily on the amplitude data shown in Figure 2-7 which is further corroborated by the well data. M-04 and L-93 22 penetrated the fluvial valley axis which can range from amalgamated braided bars, bank attached bars, interfluve islands and local flood plains. L-93 29 penetrated the fluvial valley margin which ranges from floodplains and crevasse splays to isolated crevasse channels. I-13 penetrated the unconfined floodplains consisting of paleosols and expansive floodplains and coastal plain deposits.

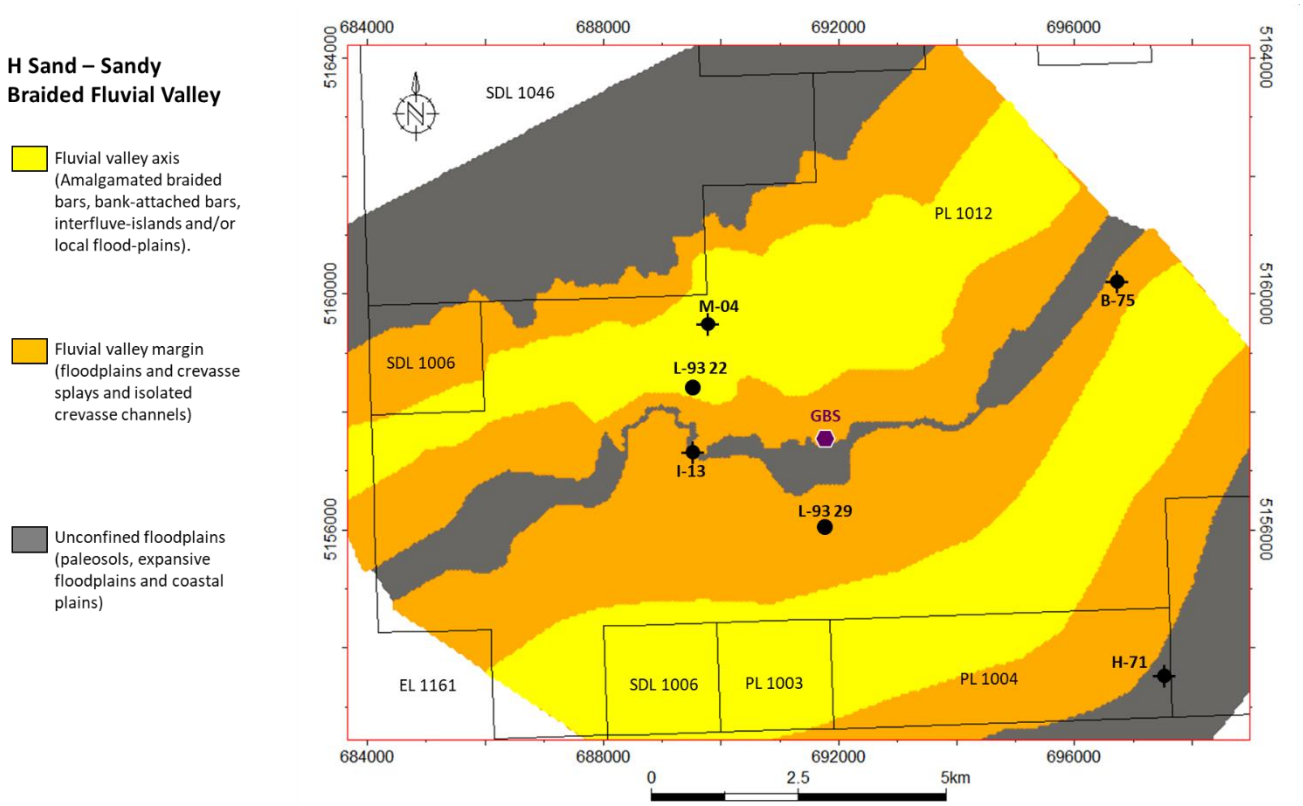


Figure 2-8: Environment of Deposition map of H Sand

2.1.2.1.2 G Sand

The G Sand has been encountered in all wells drilled to date. It is overpressured, thus connectivity to a large volume is uncertain. The environment of deposition is interpreted as a sandy braided fluvial complex. The EOD map for G Sand can be seen in Figure 2-9. L-93 22 encountered improved rock quality and sits within a fluvial channel complex consisting of amalgamated and non-amalgamated braided bars, interfluve islands and local flood plains. The remaining wells are interpreted to represent unconfined coastal plain deposits consisting of crevasse splays, isolated crevasse channels and floodplains.

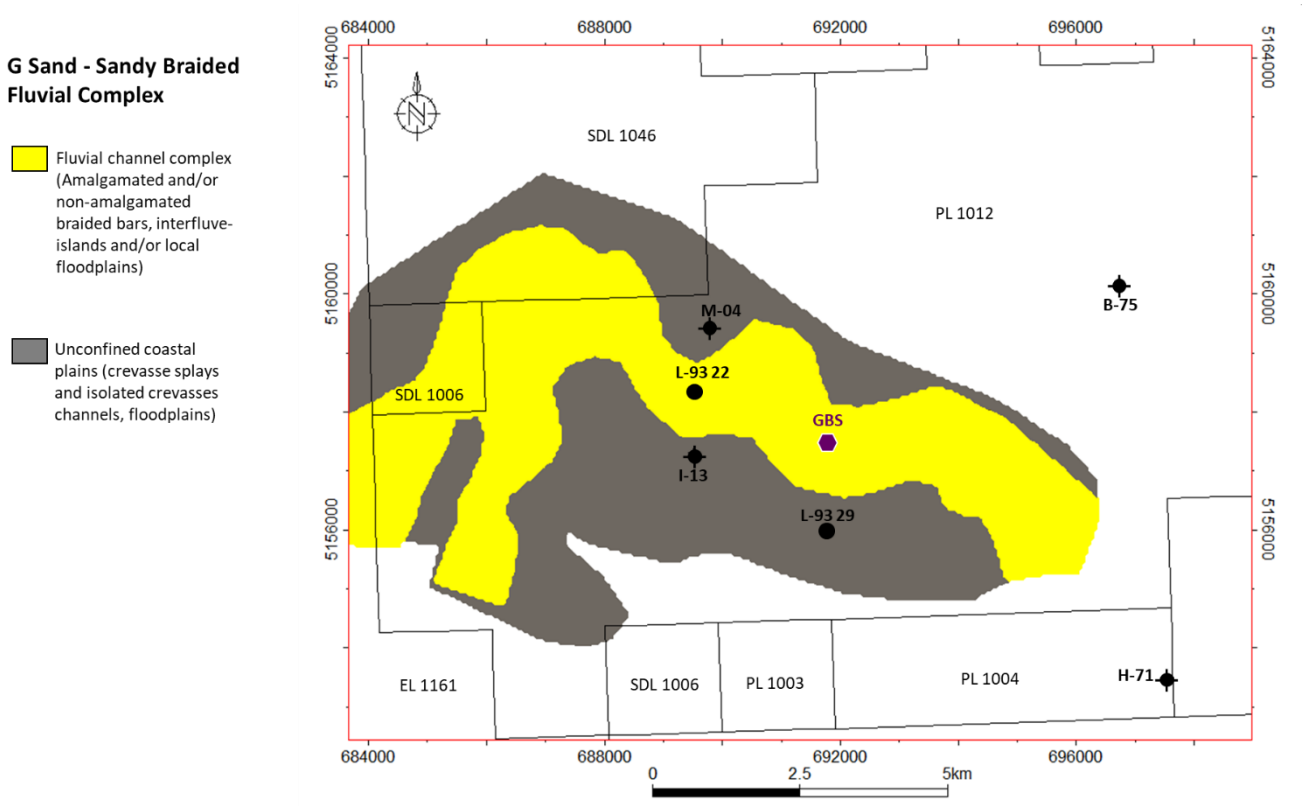


Figure 2-9: Environment of Deposition map of G Sand

2.1.2.1.3 F Sand

The F Sand is a thin sand also deposited in a sandy braided fluvial complex and is variably overpressured. M-04 is interpreted to sit on the edge of a fluvial channel complex consisting of amalgamated and non-amalgamated braided bars, interfluve islands and local flood plains. The remaining wells are interpreted to represent unconfined coastal plain deposits consisting of crevasse splays, isolated crevasse channels and floodplains. An EOD map of the F Sand is shown in Figure 2-10.

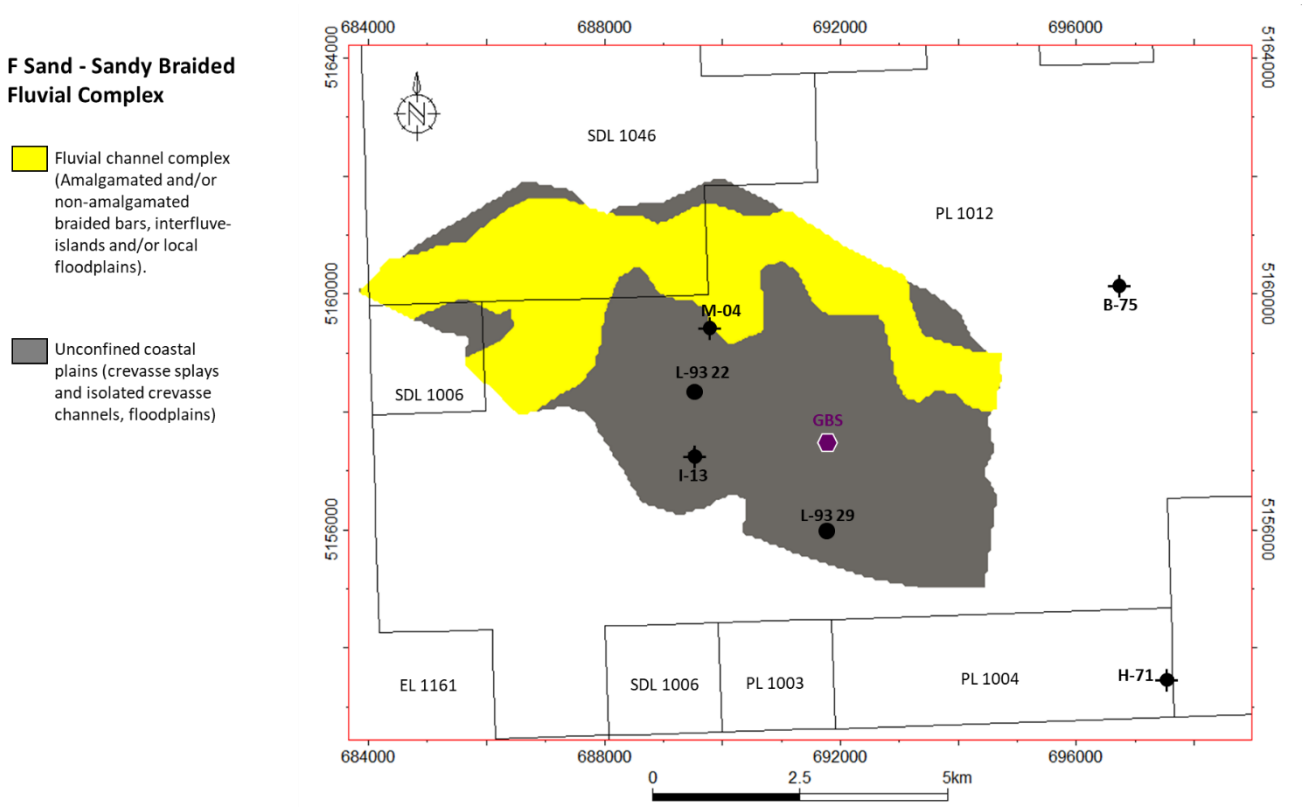


Figure 2-10: Environment of Deposition map of F Sand

2.1.2.1.4 E and D Sands

The E and D sands are interpreted to be deposited in a sandy braided fluvial complex setting which is consistent with the overall EOD of the Jeanne d'Arc Formation. Prior to L-93 22, E and D sands were considered to be non-prospective due to low quality and thin sand development from the known reservoir penetrations. L-93 22 encountered a better developed E/D interval that is comprised of: a non-porous, tight sand at the top of the E sand; 3 oil saturated, porous, and permeable sands within the E Sand; and a poor-quality D Sand (Figure 2-11)

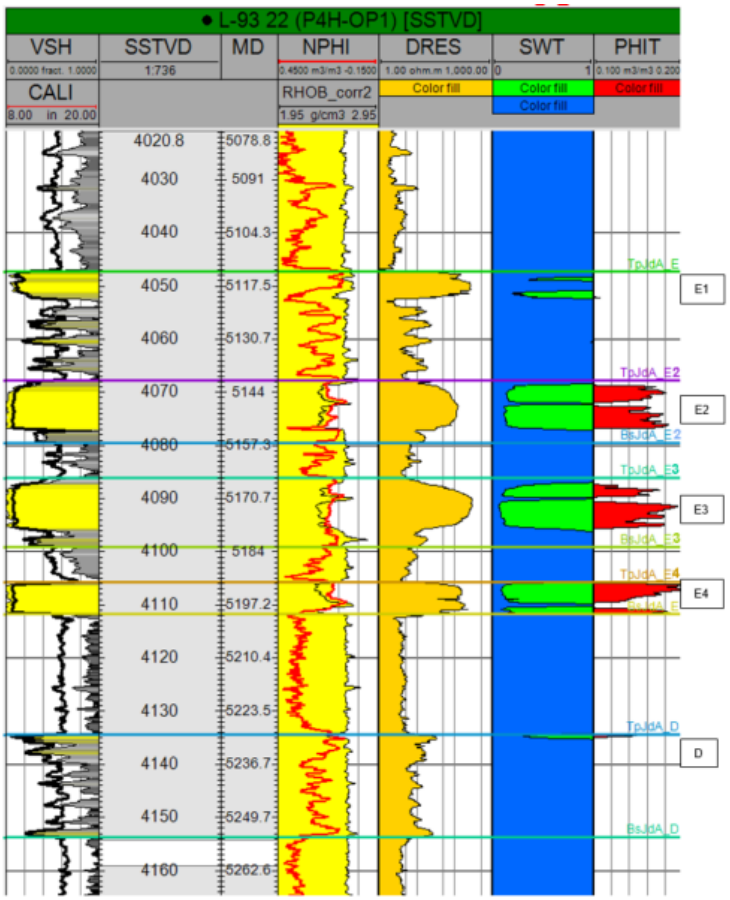


Figure 2-11: Log data through L-93 22 showing E and D Sand divisions.

Utilizing patterns in the thickness and amplitude extractions for the E Sand, a low sinuosity multi-layer channel complex is proposed (Figure 2-12 and Figure 2-13). The implied sand quality based on the sum of the negative Vp/Vs correlates with well observations as L-93 22 penetrated the best quality sands and silts within the brighter amplitude area, whereas M-04 and I-13 wells penetrated medium to dim amplitudes and saw poor reservoir quality.

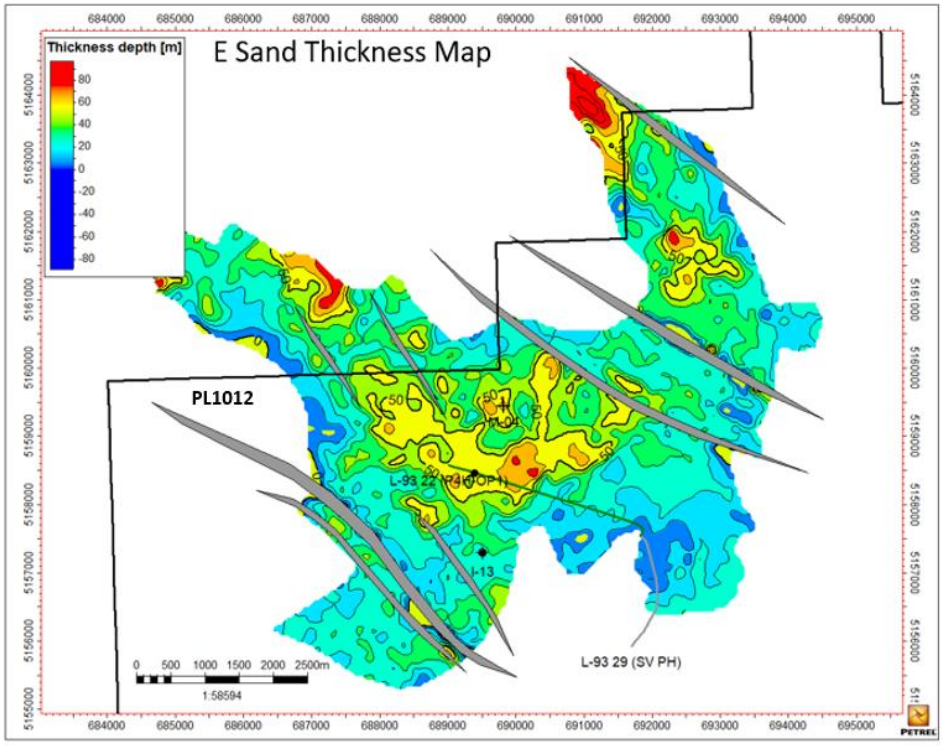


Figure 2-12: E Sand - Thickness Map

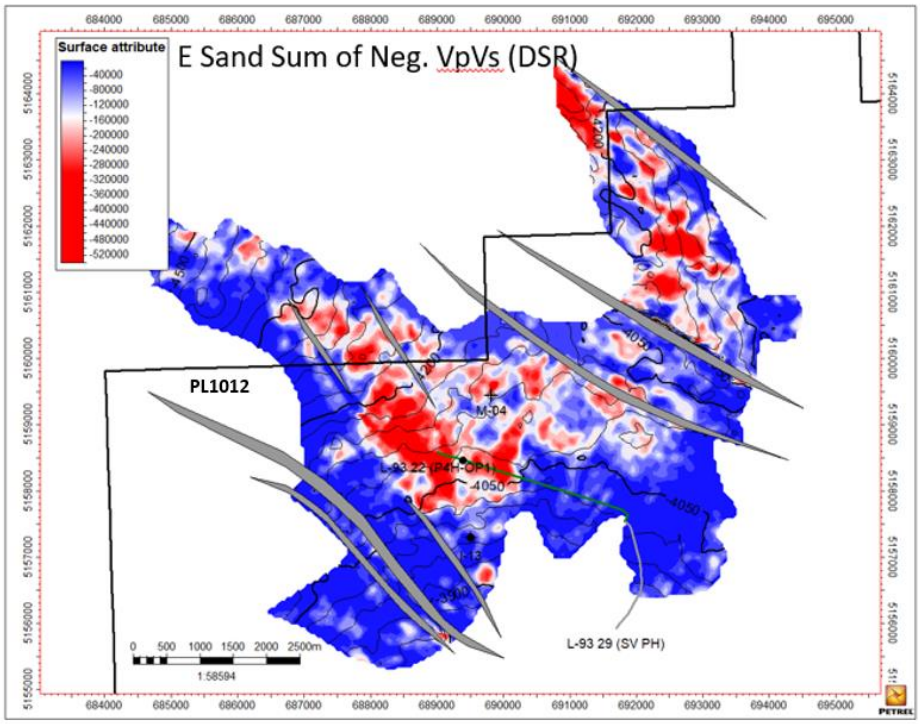


Figure 2-13: E Sand - Sum of Negative Vp/Vs (DSR)

Using the amplitude and thickness data, an EOD map of the E Sand deposition is proposed in Figure 2-14. The map shows predominantly unconfined coastal plain deposits comprised of crevasse splays and

isolated crevasse channels with floodplain deposits. Locally, stacking of better quality discrete braided channels in the fluvial channels is possible. L-93 22 is interpreted to penetrate one such area where the valley direction turns to the north. This may be controlled in part by minor faulting influencing the paleogeography.

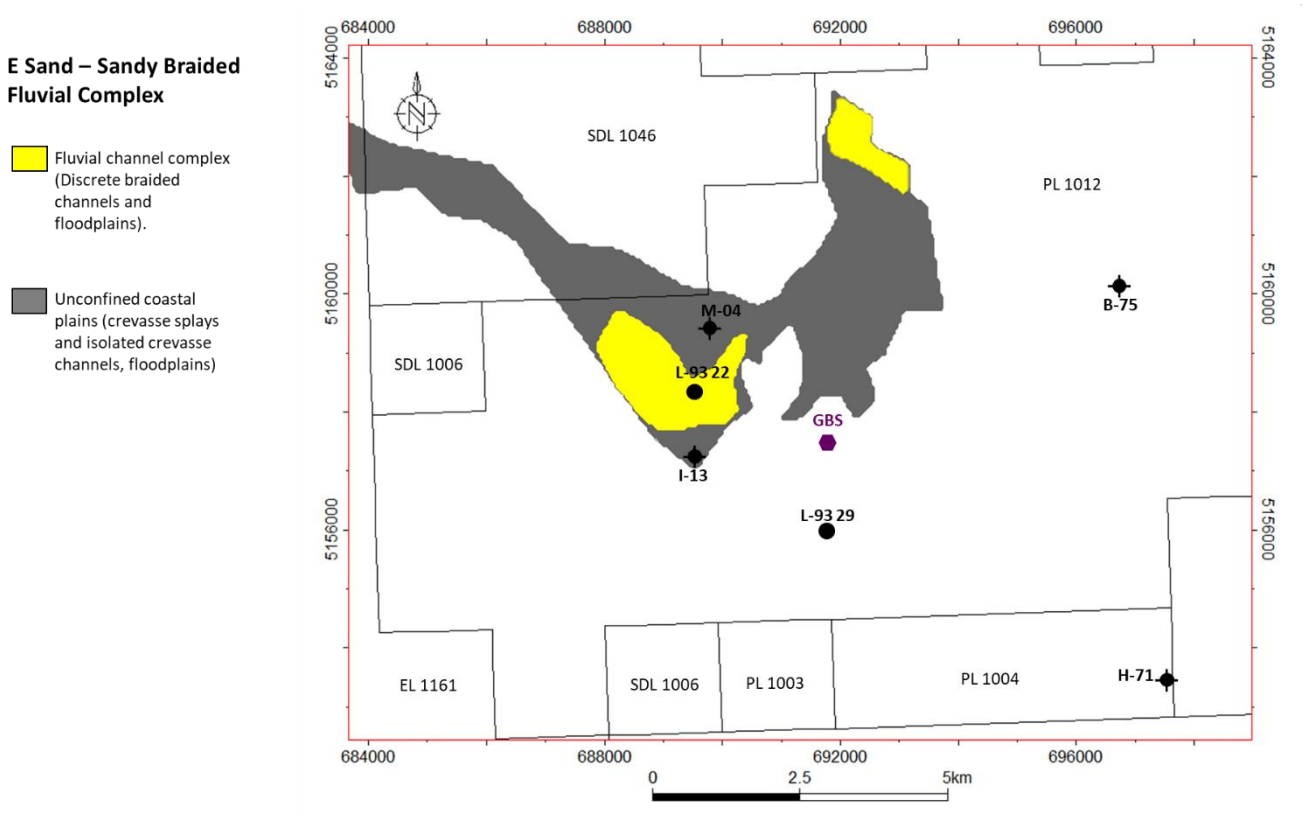


Figure 2-14: Environment of Deposition map of E Sand

A similar amplitude analysis was done with the D Sand but using the maximum amplitude of the DSR near dataset (Figure 2-15 and Figure 2-16). The D Sand is variable and not always fully resolved on seismic data. A base E Sand to top C Sand thickness map provides some guidance on the general orientation and the potential footprint of the D Sand. The thickest area of this interval appears to be located to the north of the E Sand thick and may be indicative of compensational stacking of the sands. The M-04 well penetrated the northern side of the sand, whereas L-93 22 penetrates off axis on the south side. The D Sand is not present in the I-13 well.

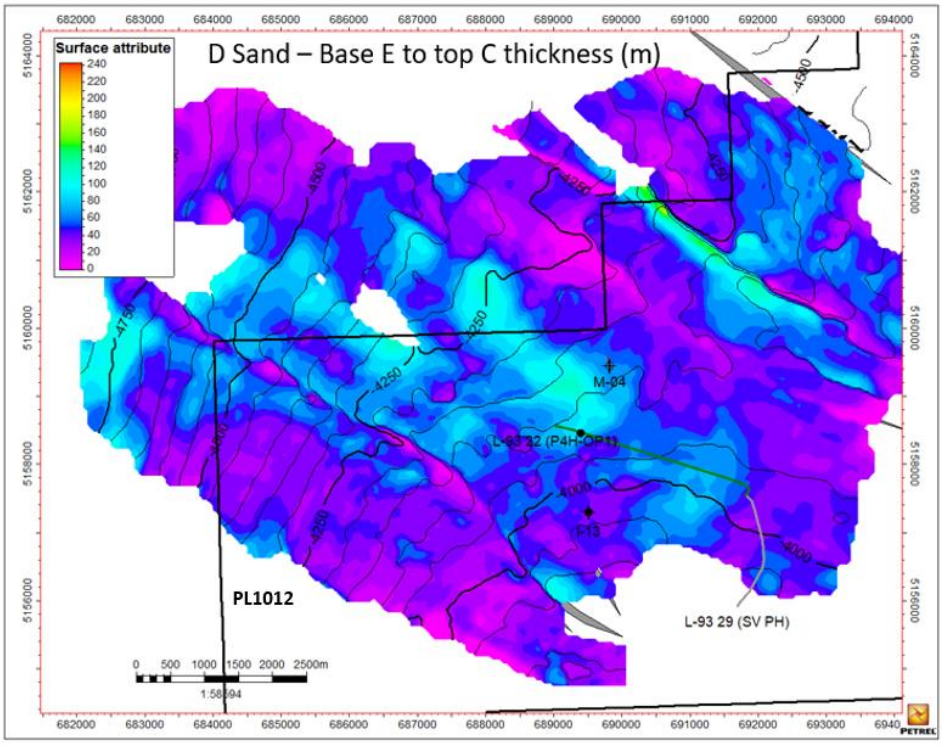


Figure 2-15: Thickness map between base of E Sand and top of C Sand.

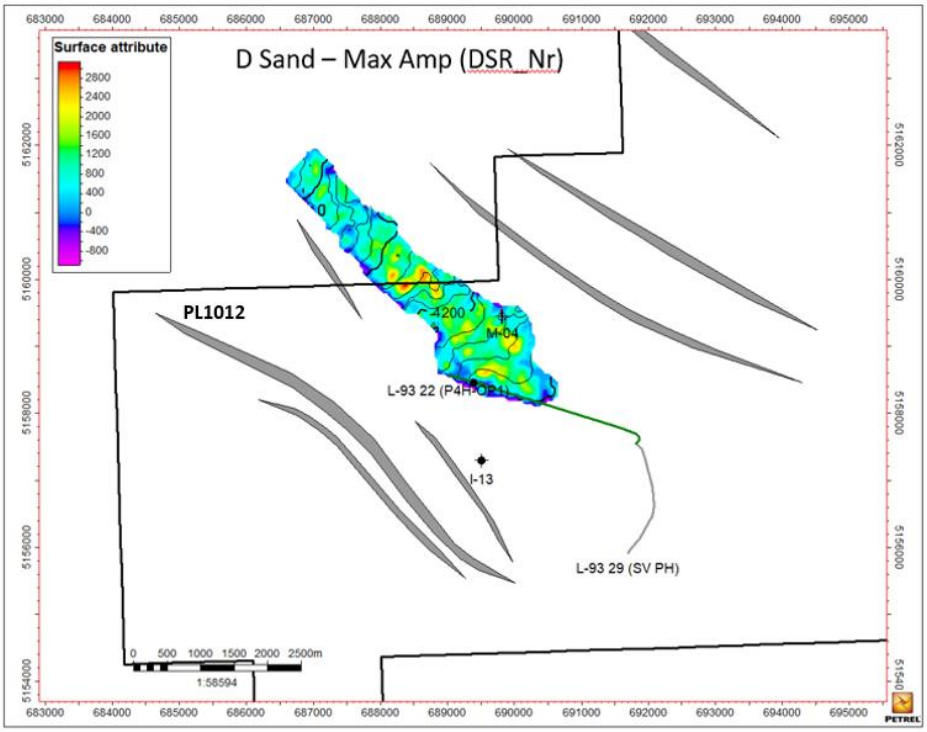


Figure 2-16: D Sand - Maximum Amplitude from DSR Near

2.1.2.1.5 C Sand

The C Sand Complex has been encountered in all Hebron Horst wells drilled to date (As observed in Figure 2-6); however, only L-93 29 encountered oil. It is divided into an upper and lower unit and sand development is variable. It is usually 85-100m thick with variably amalgamated sands which tend to grade upward into silty sands. Limited core is available from I-13 but includes pebbly sandstone and trough cross bedded sandstones which are likely indicative of point bars within a meandering fluvial channel complex. L-93 29 encountered good quality reservoir in both the upper and lower C Sand Complex. Given the variability of the C Sand observed in the well data, the degree of amalgamation of channel complexes is uncertain. Thickness and amplitude extractions may indicate better sand development in the vicinity of L-93 29 (Figure 2-17 and Figure 2-18).

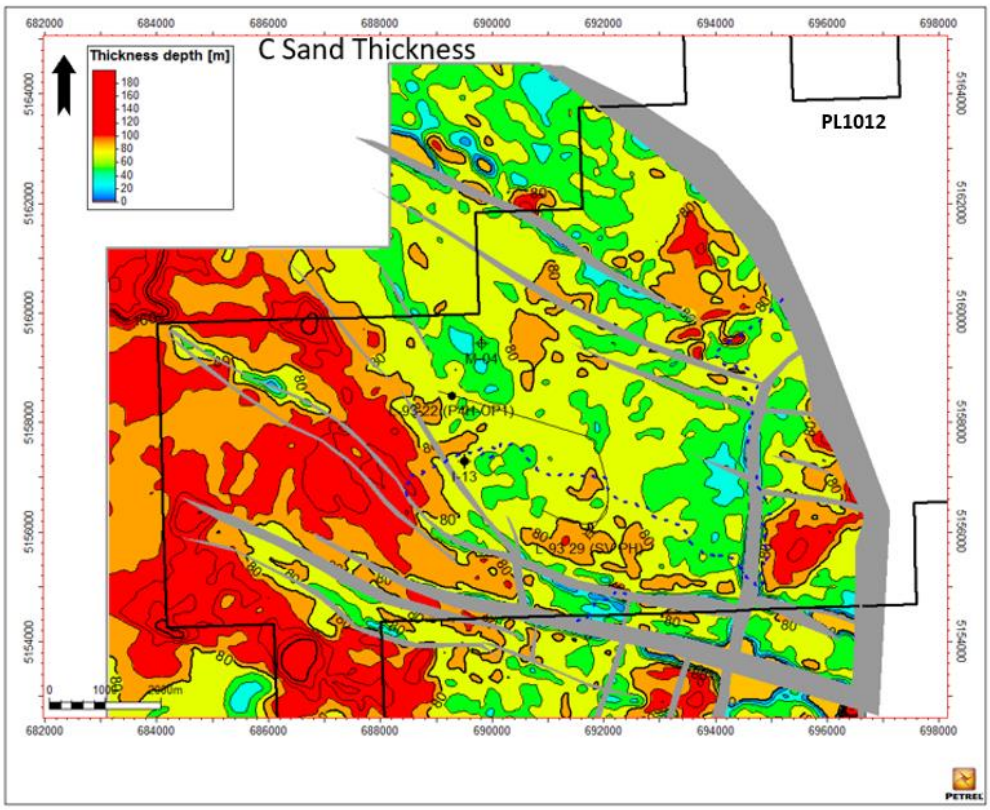


Figure 2-17: C Sand Complex - Thickness map

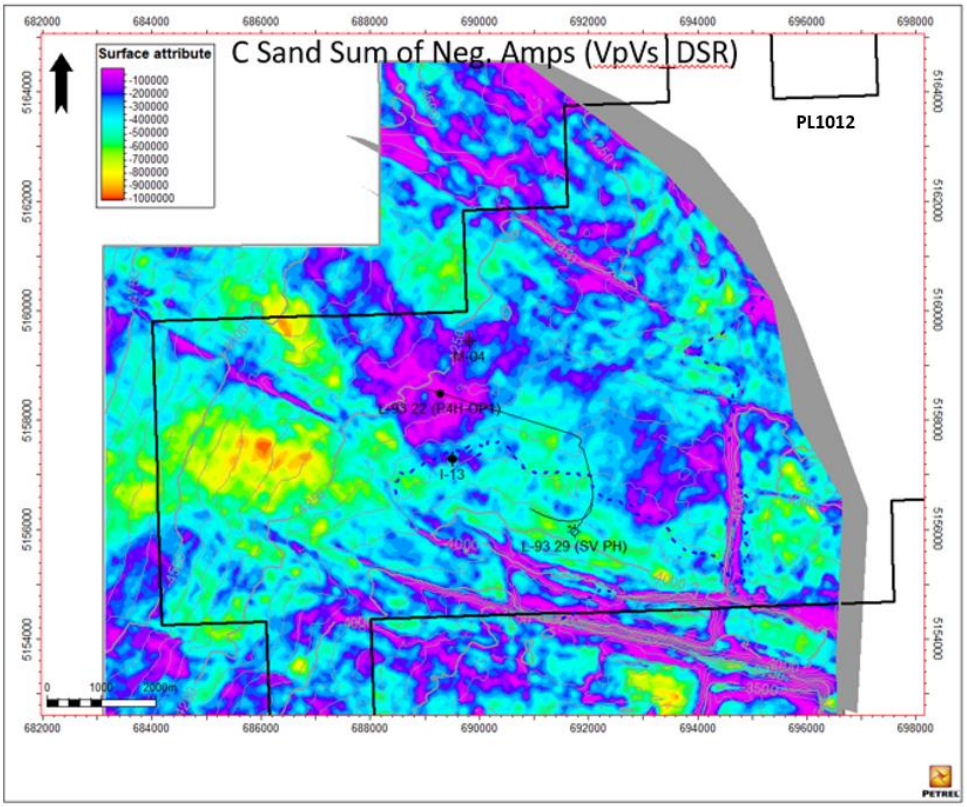


Figure 2-18: C Sand Complex - Sum of negative amplitudes (Vp/Vs DSR)

EOD maps were created for both the upper (Figure 2-19) and lower (Figure 2-20) C Sand to reflect observations from the well data. The overall EOD is a meandering fluvial complex. The upper C Sand features a west-east trending fluvial point bar complex composed of mid channel bars and point bars with potential oxbows and crevasse splays. Outside of this area the overall EOD is interpreted as unconfined coastal plans which consists of crevasse splays, isolated crevasses channels and floodplain deposits.

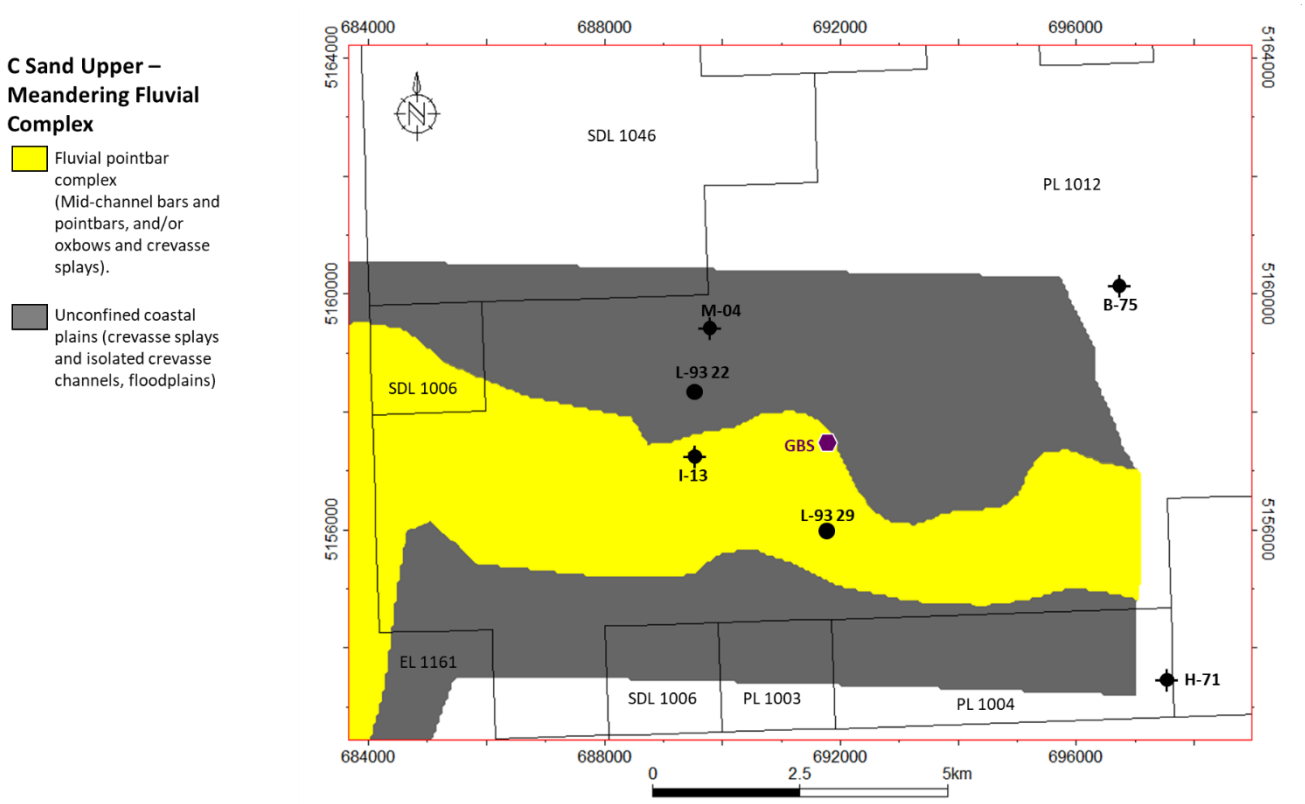


Figure 2-19: Environment of Deposition map of C Sand (Upper)

The fluvial point bar complex is interpreted to be more widespread in the lower C Sand but similar to the upper this EOD element is comprised of mid channel bars and point bars with oxbows and crevasse splays. The remaining area is interpreted as unconfined coastal plains with crevasse splays, crevasse channels and floodplain deposits.

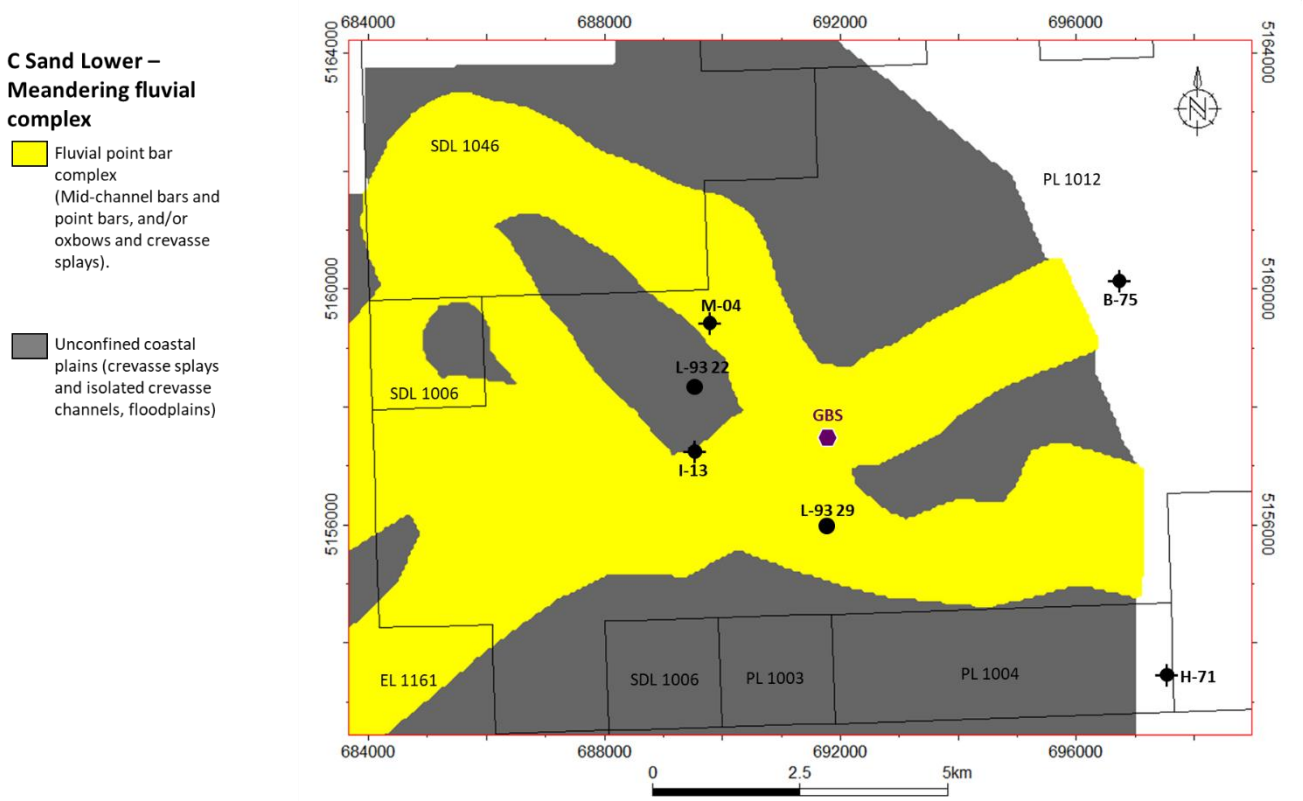


Figure 2-20: Environment of Deposition map of C Sand (Lower)

2.1.2.1.6 BC Stringers

No EOD maps were created for the BC Stringer interval. These sands are predominantly wet with variable thickness and reservoir quality. Individual sands are separated by shales and do not appear to be amalgamated.

2.1.2.1.7 B Sand

The B Sand has been discussed in prior submissions to the C-NLOPB, including the Hebron Development Plan. It is a sandy braided fluvial complex consisting of a braided bar complex of amalgamated braided bars and local interfluve islands. The unconfined flood plain contains isolated braided bar channels with local channels, floodplain and potent crevasse splay deposits. The coastal plain deposits are composed of paleosols and floodplains. The B Sand is subdivided into Upper and Lower units, which are porous and permeable, that underlie a marl unit ('B Marl'). While the B Marl has porosity, it has limited permeability.

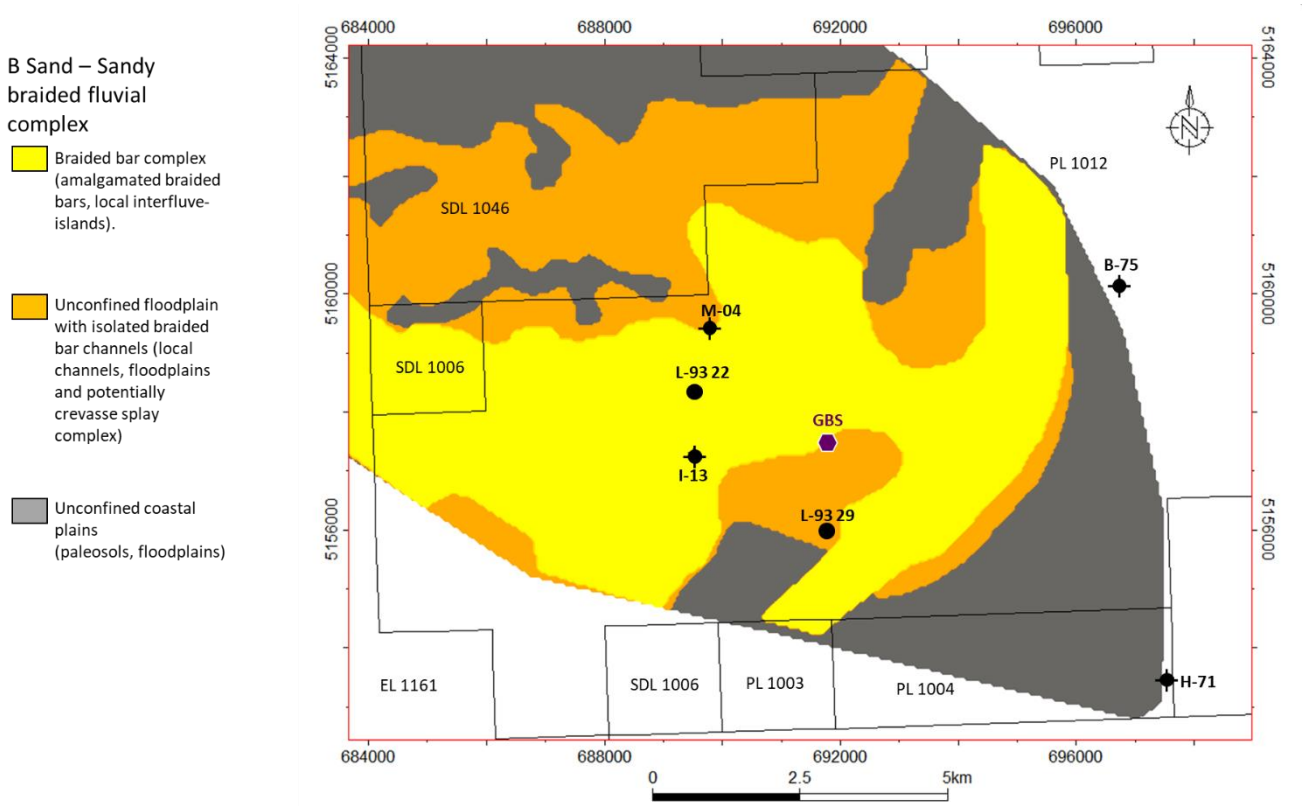


Figure 2-21: Environment of Deposition map of B sand

The Hebron Horst block has been penetrated by four wells from a flank to crestal position. Additional sand units outside of the currently named units are possible although not expected to be laterally extensive. In addition, small sand stringers encountered in the existing wells may develop into thicker or better quality intervals. Similarly, these are not anticipated to be laterally extensive. Holistic Jeanne d'Arc Formation interpretations and correlations will be updated as new data become available.

2.1.2.2 Jeanne d'Arc Formation Structural Geology

At the level of the Jeanne d'Arc Formation, additional faulting not seen in the shallower Ben Nevis Formation is observed. This includes minor, low throw faults within the Hebron Horst block and a redefinition of the horst on the eastern side where intersection with north-south faults has creates additional blocks (Figure 2-22).

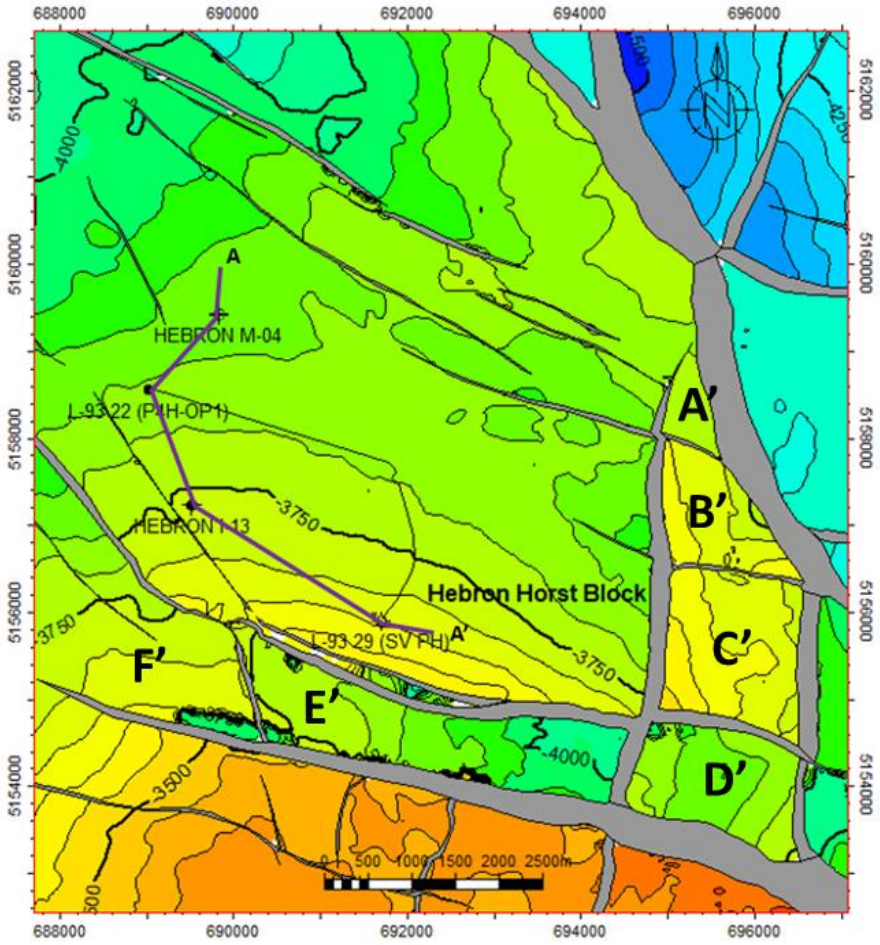


Figure 2-22: Structure map on the top Jeanne d'Arc Formation showing surrounding fault blocks A', B' and C' fault blocks are a result of intersection of the horst block and the north-south fault trend. D', E' and F' are the faulted deeper equivalents of the Ben Nevis I-13 fault block.

No substantial growth is observed in the Jeanne d'Arc Formation related to faulting although minor thickness changes and deflections in fluvial systems may be interpreted. This could be related to subtle fault controlled paleogeography.

In addition to mapping the faults and sands within the Jeanne d'Arc Formation, juxtaposition relationship maps were constructed and annotated using colour arrows to reflect the connections across faults. These juxtaposition maps provide a useful visualization of the potential extent of hydrocarbon accumulations based on cross fault juxtaposition. The legend for the maps is shown in Figure 2-23 below:

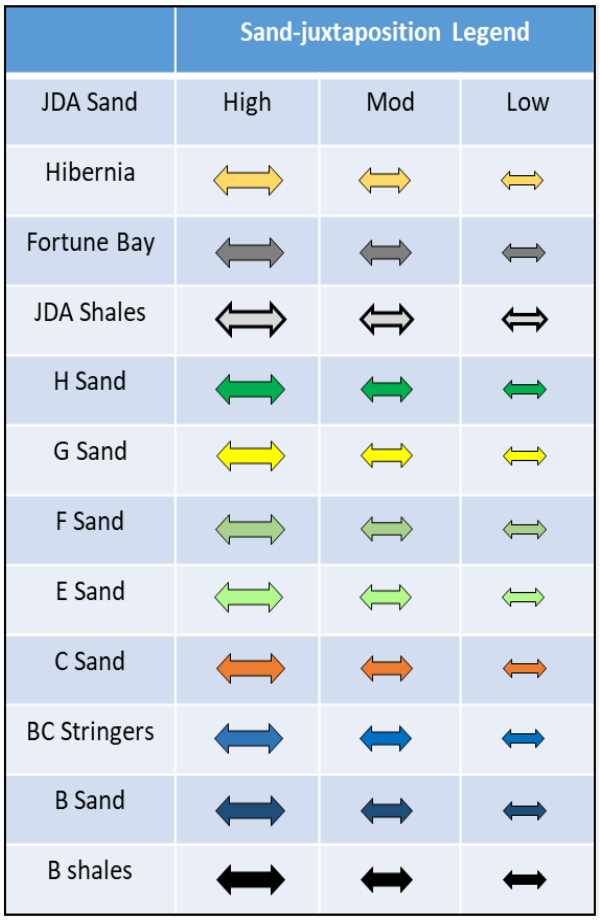


Figure 2-23: Legend for the juxtaposition maps
Arrow colour indicates stratigraphic interval and arrow size is a qualitative assessment of confidence in the connection
(e.g., large arrows = greater confidence in connection).

Similar to the Jeanne d'Arc Formation sand names, the fault blocks surrounding the Hebron Horst block are also alphabetically named. The fault blocks are labelled clockwise from northeast to southwest as Fault Block A', B', C', D', E', and F'. These fault blocks ring the Hebron Horst Block along the east and southern sides.

2.1.2.2.1 H Sand

The H Sand is the uppermost sand of the Jeanne d'Arc Formation. The downdip North Valley is largely self-juxtaposed or juxtaposed against shales of the Fortune Bay. At the crest, the South Valley section is juxtaposed against the Hibernia Formation (light orange arrows) and possibly to the C Sand (dark orange arrows).

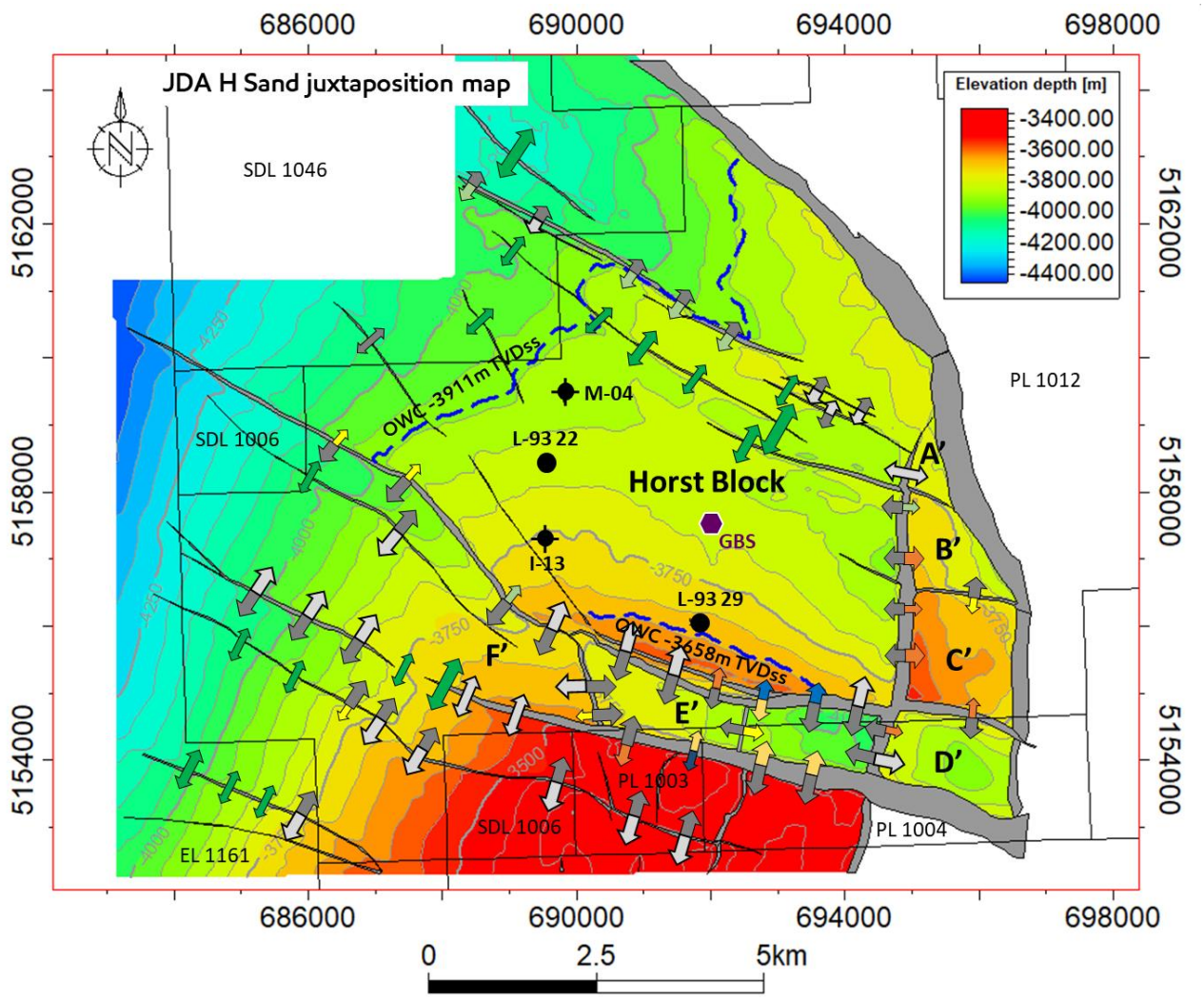


Figure 2-24: H Sand - Juxtaposition relationship map
Legend shown in Figure 2-23

2.1.2.2.2 G Sand

The G Sand is thin and predominantly juxtaposed against shales. There is a juxtaposition to the Lower Hibernia Sandstone in Fault Block E' to the south.

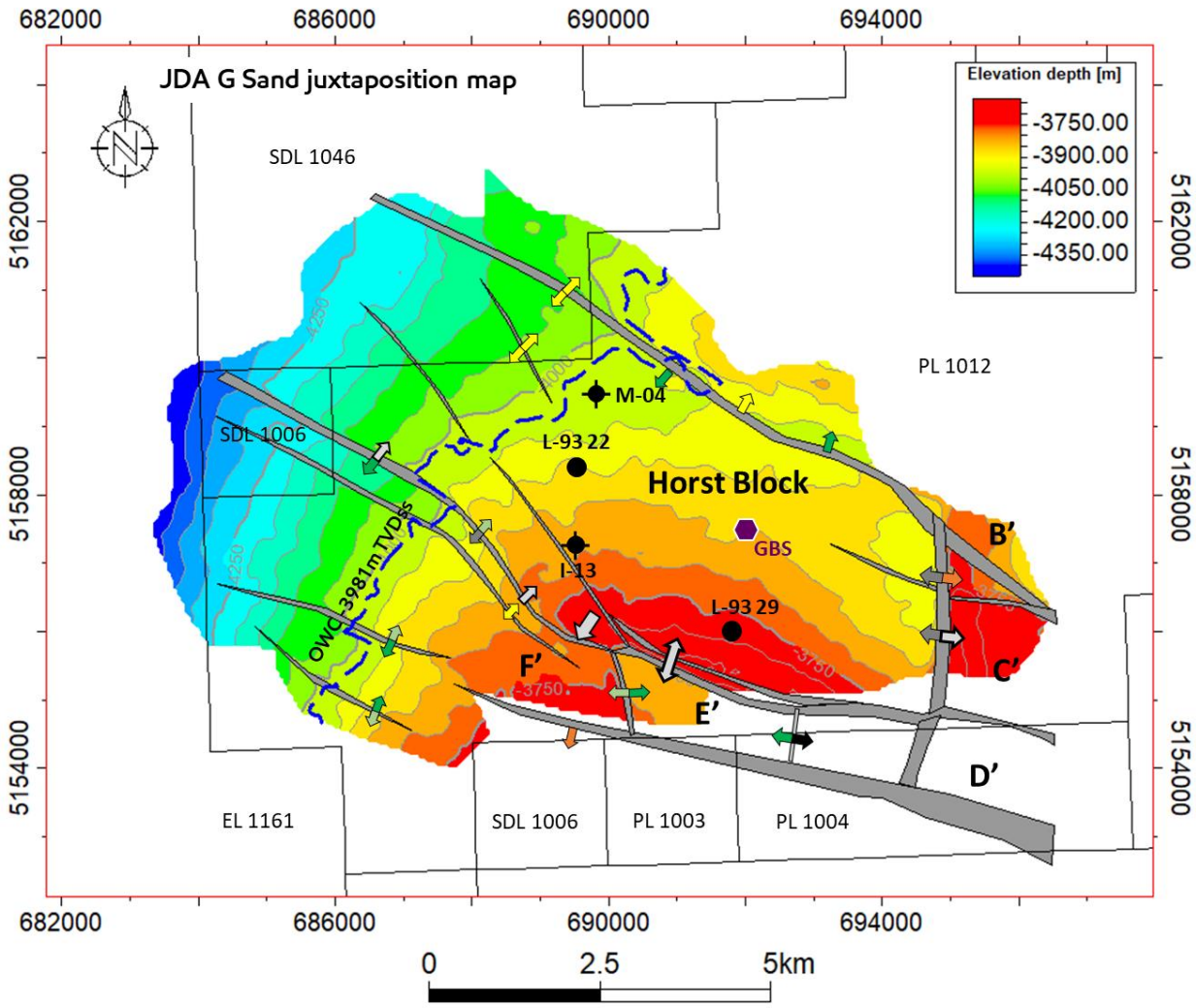


Figure 2-25: G Sand - Juxtaposition relationship map
Legend shown in Figure 2-23

2.1.2.2.3 F Sand

The F Sand is thin and, similar to the G Sand, is predominantly juxtaposed against shales. There is a potential juxtaposition relationship from Fault Block E' to the C Sands of the Horst Block (orange arrow).

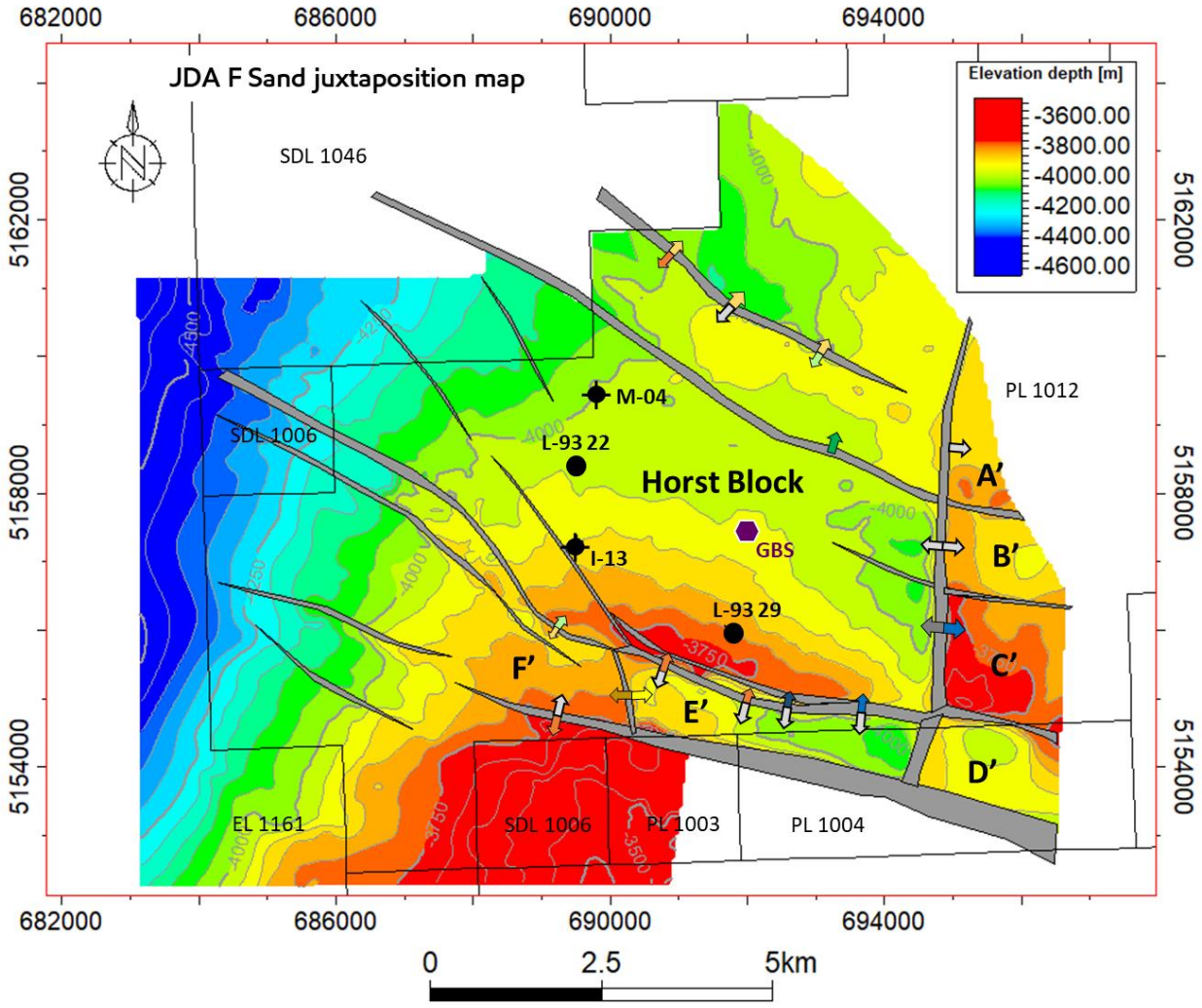


Figure 2-26: F Sand - Juxtaposition relationship map
Legend shown in Figure 2-23.

2.1.2.2.4 E/D Sand

The E/D Sand complex has limited areal extent. It is self-juxtaposed across most of the faults or juxtaposed against shale where fault offset increases.

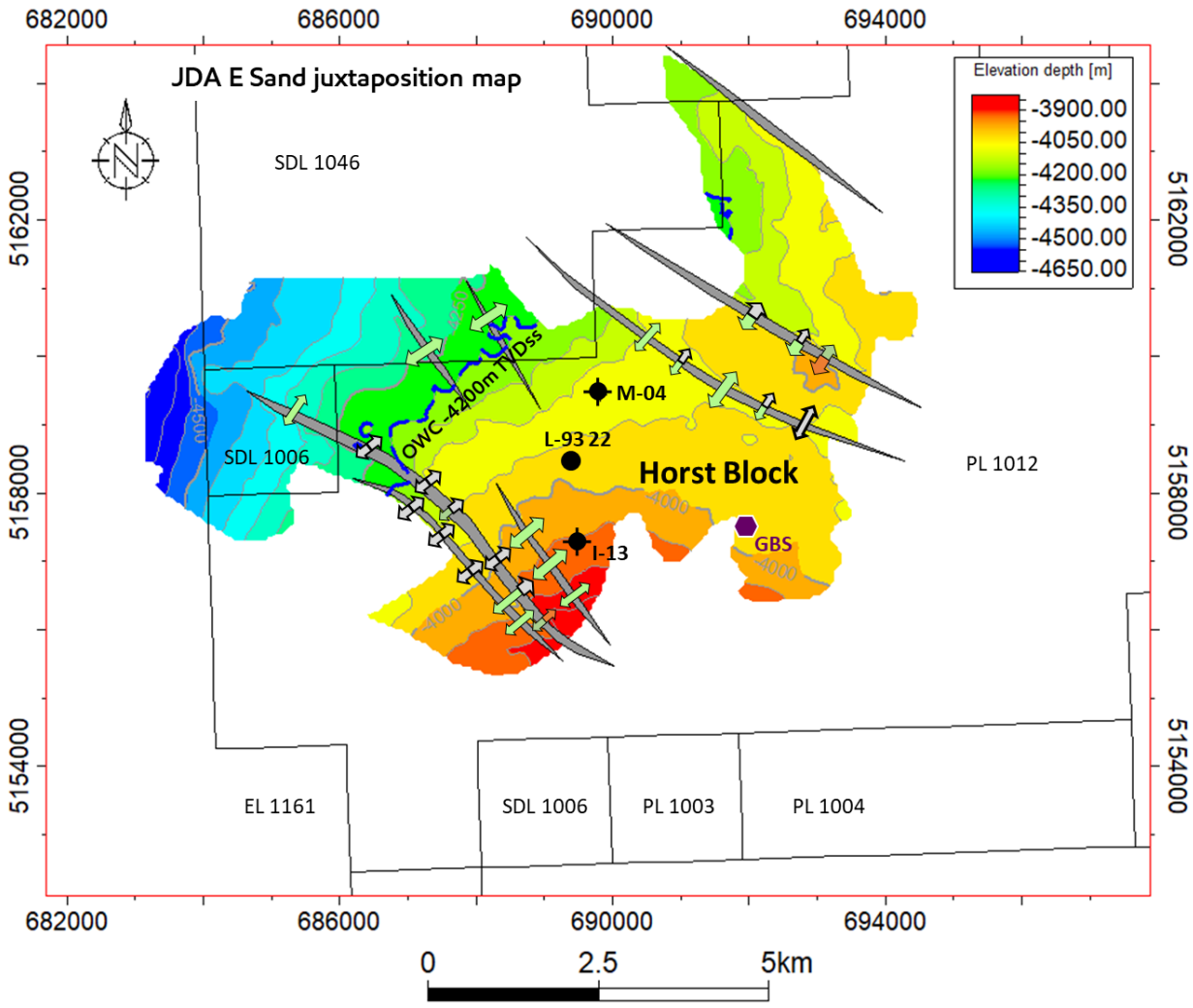


Figure 2-27: E/D Sand Complex - Juxtaposition relationship map
Legend shown in Figure 2-23

2.1.2.2.5 C Sand

The C Sand complex is the thickest interval within the Jeanne d'Arc Formation and self-juxtaposition across faults is common. The hydrocarbon accumulation at the crest of the Horst Block appears to be fault dependent with juxtaposition to Fortune Bay Shales to the south although the accumulation may spill into Fault Block F'. A potential connection to the B Sand is mapped in Fault Block C' (dark blue arrow) with the C Sand in that same fault block potentially connecting to the H Sand in South Valley (green arrow).

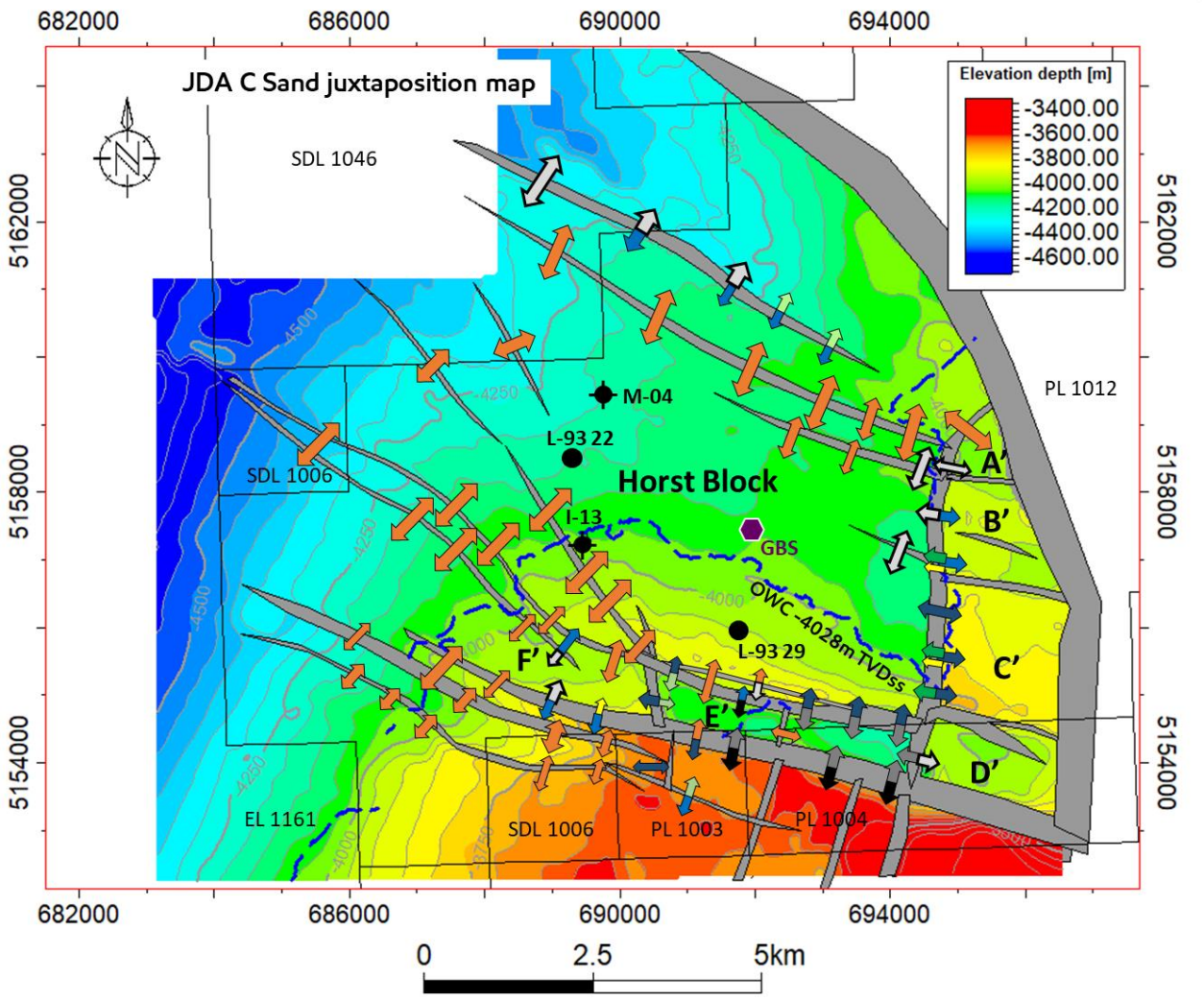


Figure 2-28: C Sand - Juxtaposition relationship map
Legend shown in Figure 2-23

2.1.2.2.6 B Sand

The most common connections in the B Sand are self-juxtaposition or juxtaposition to the underlying shales. The most significant relationship is the potential for the B Sand in Fault Block C' to connect to the C Sand in the Hebron Horst (orange arrows).

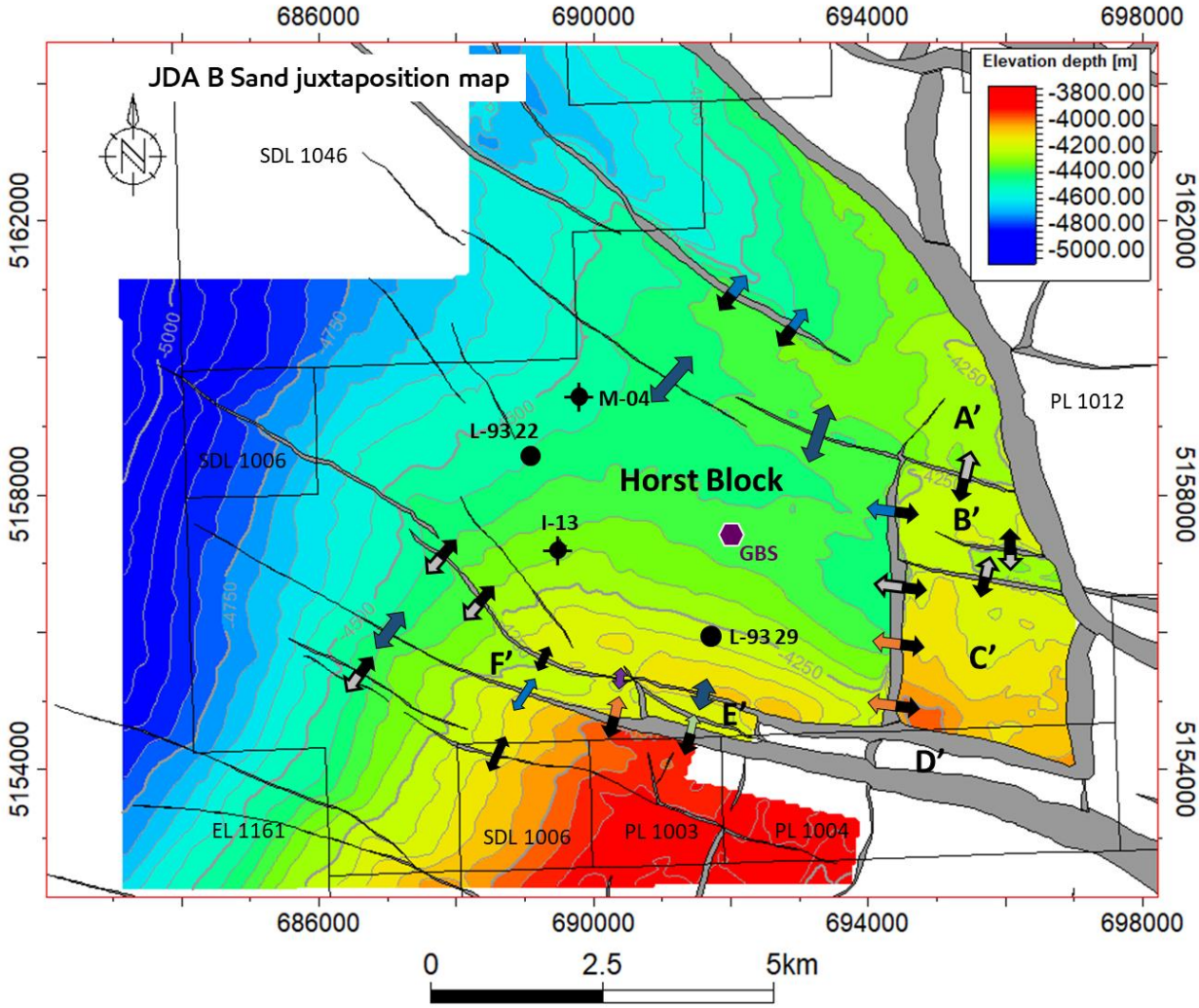


Figure 2-29: B Sand - Juxtaposition relationship map
Legend shown in Figure 2-23

The juxtaposition relationships form the basis for understanding the hydrocarbon accumulations within the Jeanne d'Arc Formation and develops the foundation for inclusion of fault blocks A' to F' in the DPA.

2.1.3 Hydrocarbon Accumulation in the Hebron Horst and Surrounding Fault Blocks

As part of analysis informing this DPA submission, well, seismic, pressure data, and juxtaposition relationships have been integrated into hydrocarbon accumulation maps for the various JDA sandstone intervals mapped at Hebron. These accumulations extend beyond the well penetrations on the Hebron Horst and into the surrounding fault blocks. The extent of the accumulation is a necessary input into the development plan. Integrated maps of the hydrocarbon accumulations by sand are shown below.

2.1.3.1 H Sand

The H Sand is divided into North and South valleys. These valley systems are hydraulically disconnected and separated. The oil water contact for North Valley is -3912m TVDss and the extent of the hydrocarbon accumulation is defined by the OWC and the stratigraphic valley edges.

The South Valley extent is a fault dependent three-way closure at the crest of the Hebron Horst Block with an oil water contact defined in L-93 29 of -3657.5m TVDss.

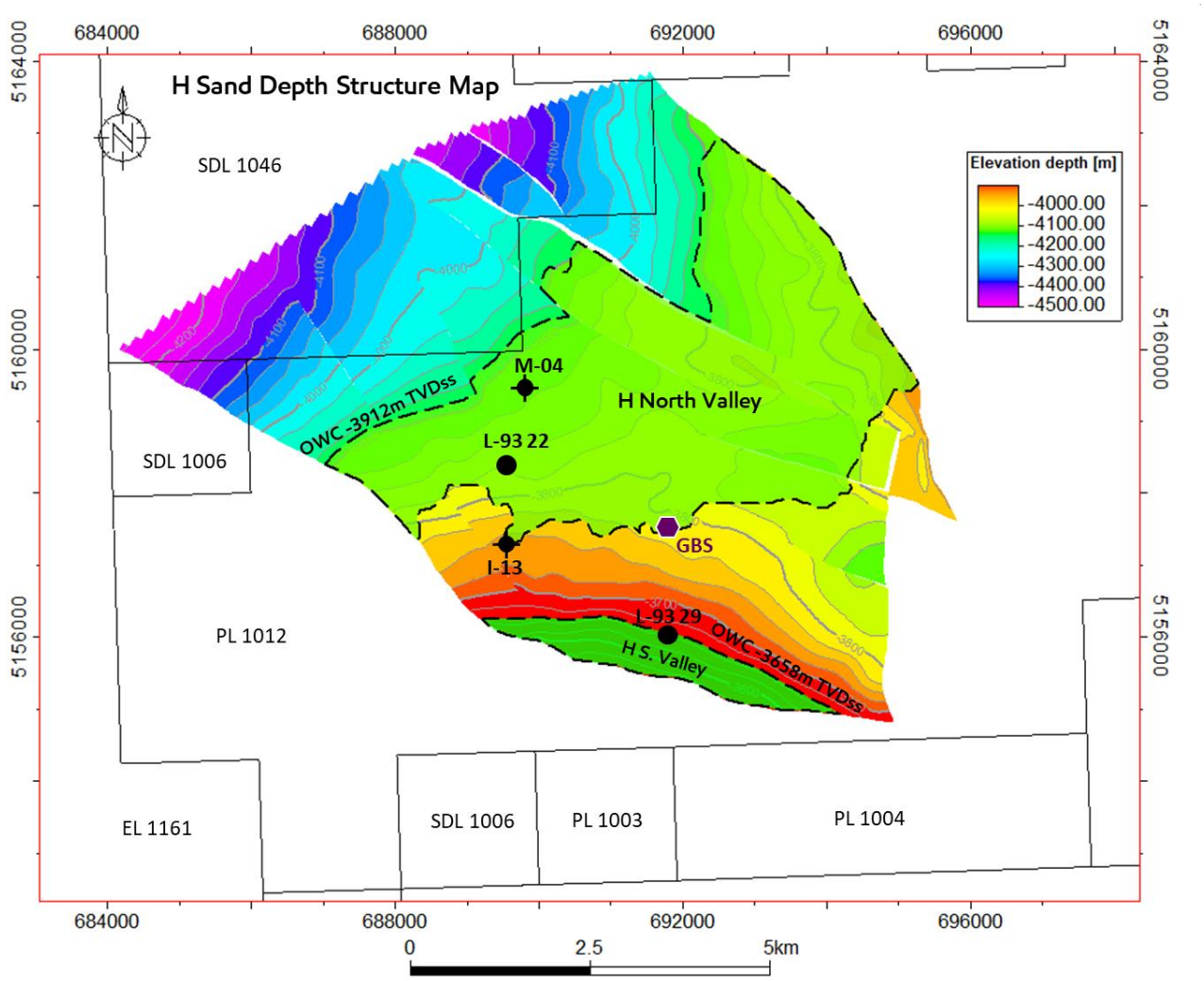


Figure 2-30: Top H Sand structure map
Shows outlines for the North and South Valley hydrocarbon accumulations.

2.1.3.2 G Sand

The G Sand accumulation is defined by an oil down to (ODT) of -3978m TVDss and extends to the east in fault blocks B' and C' where it is juxtaposed against the C Sand.

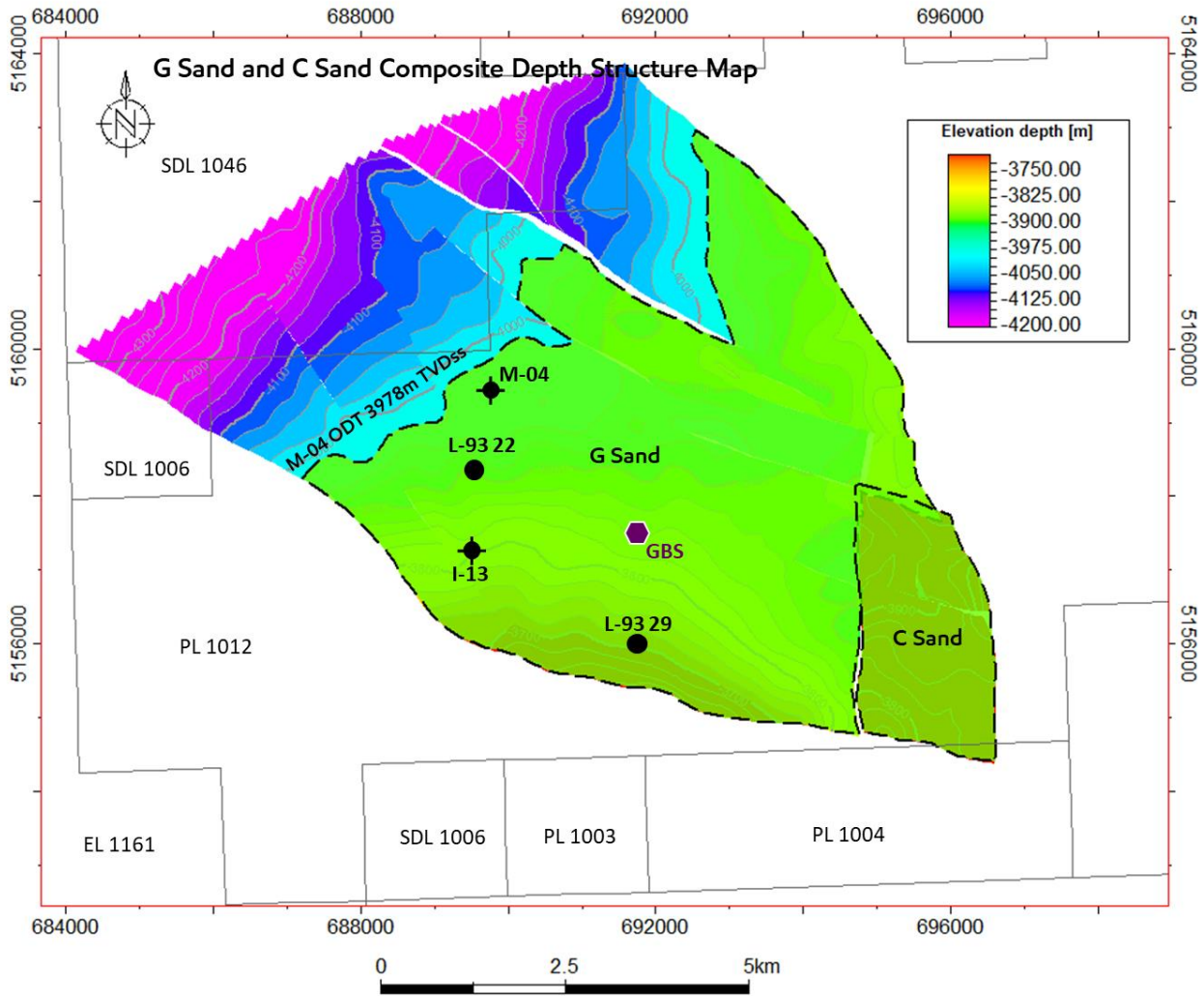


Figure 2-31: Top G Sand structure map
Shows outline of the G Sand accumulation on the Horst block and connection to the C Sand to the east

2.1.3.3 F Sand

The F Sand accumulation is defined by an oil water contact at -3980m TVDss and extends to Fault Block E' to the south where there is a juxtaposition with the Lower Hibernia Sandstone (LHS).

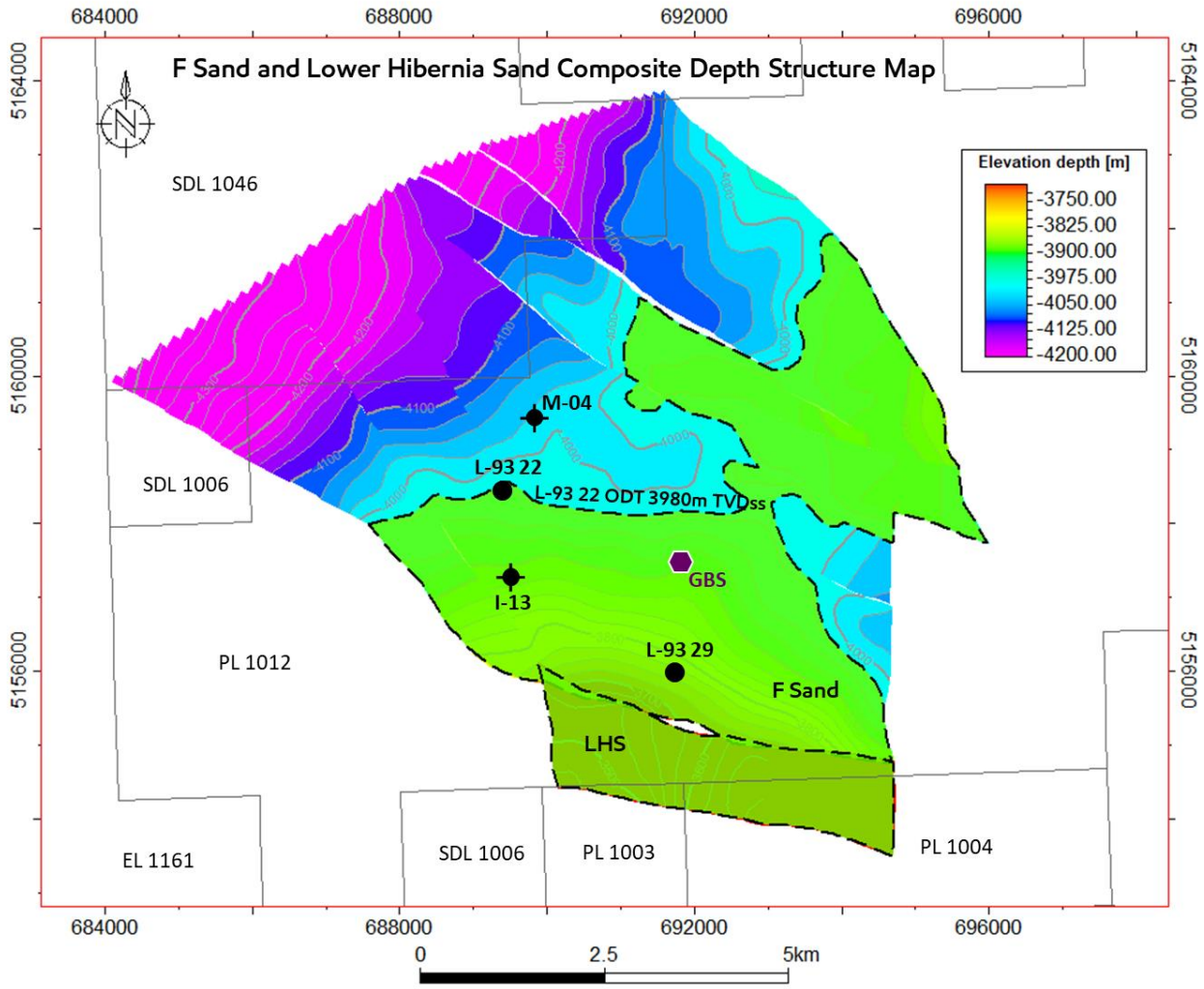


Figure 2-32: Top F Sand structure map
Outlines F Sand accumulation and the connection to the Lower Hibernia Sandstone (LHS) to the south.

2.1.3.4 E/D Sand

The E/D Sand accumulation is defined by an oil water contact at -4200m TVDss and the mapped stratigraphic extent of the E and D Sands. The updip extent of the pool includes the crest of the structure to capture the D Sand in L-93 29 which is interpreted to be in communication with the E/D Sand encountered in down dip wells.

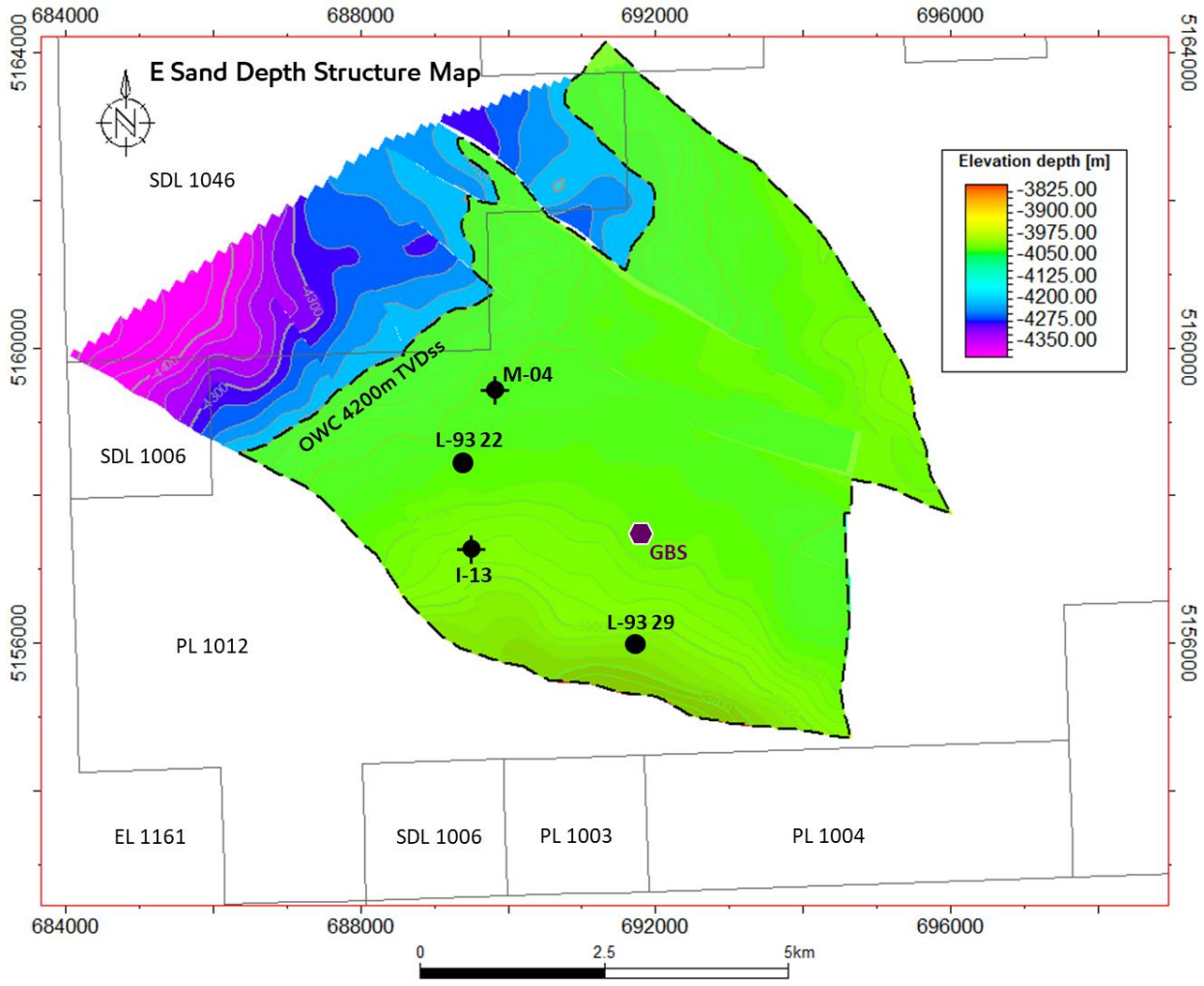


Figure 2-33: Top E Sand structure map
Outlines E/D Sand hydrocarbon accumulation on the Hebron Horst block.

2.1.3.5 C Sand

The C Sand accumulation is defined by the oil water contact at -4028m TVDss in the C Sand on the Hebron Horst block and includes fault blocks E' and F' in the south where is it connected to the C, E, and H sands.

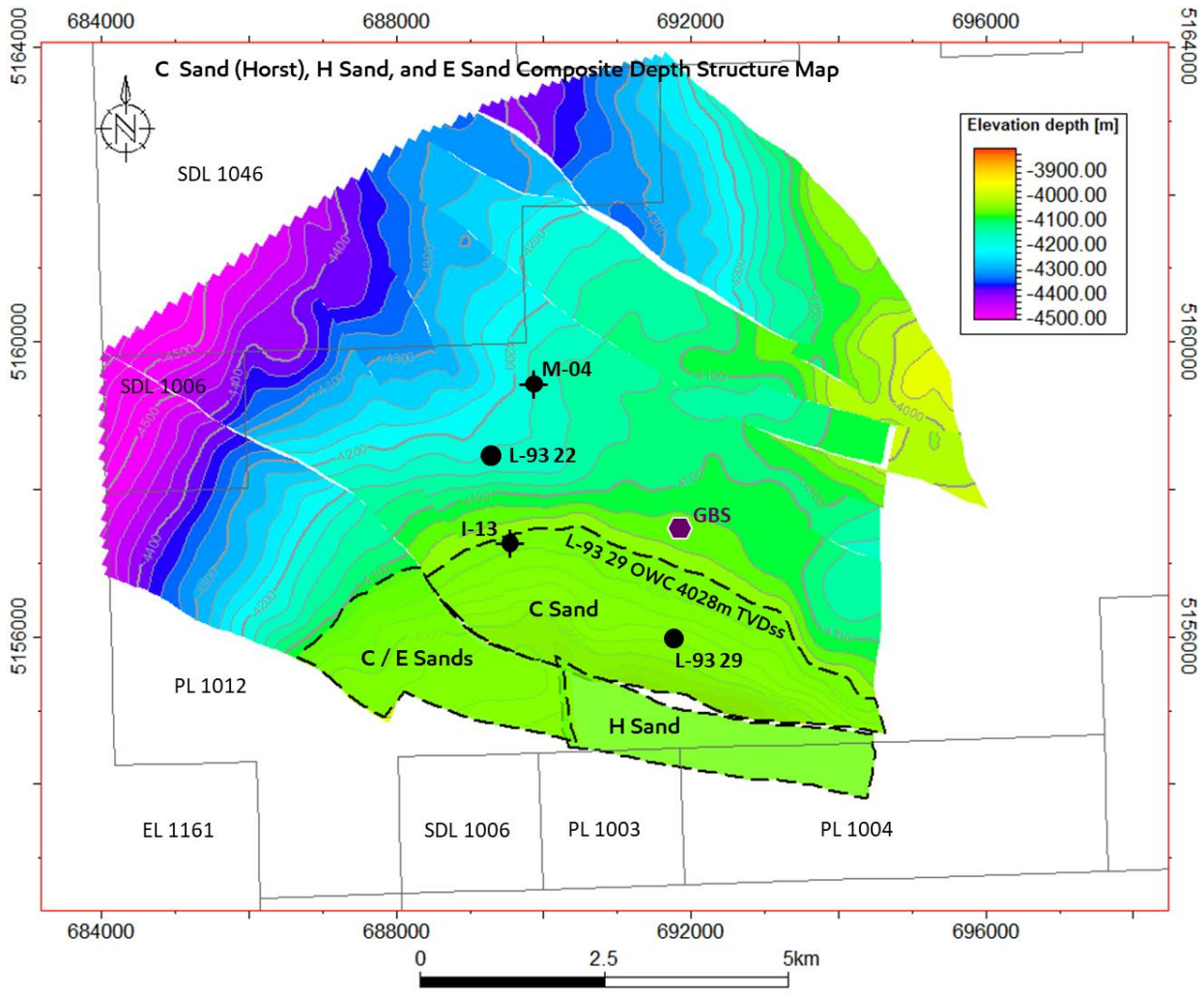


Figure 2-34: Top C Sand structure map
Outlines C Sand hydrocarbon extent including connection to fault blocks to the south.

2.1.3.6 B Sand

The B Sand is defined by the oil water contact at -4520m TVDss and includes a connection to the C Sand located in Fault Block E' to the south.

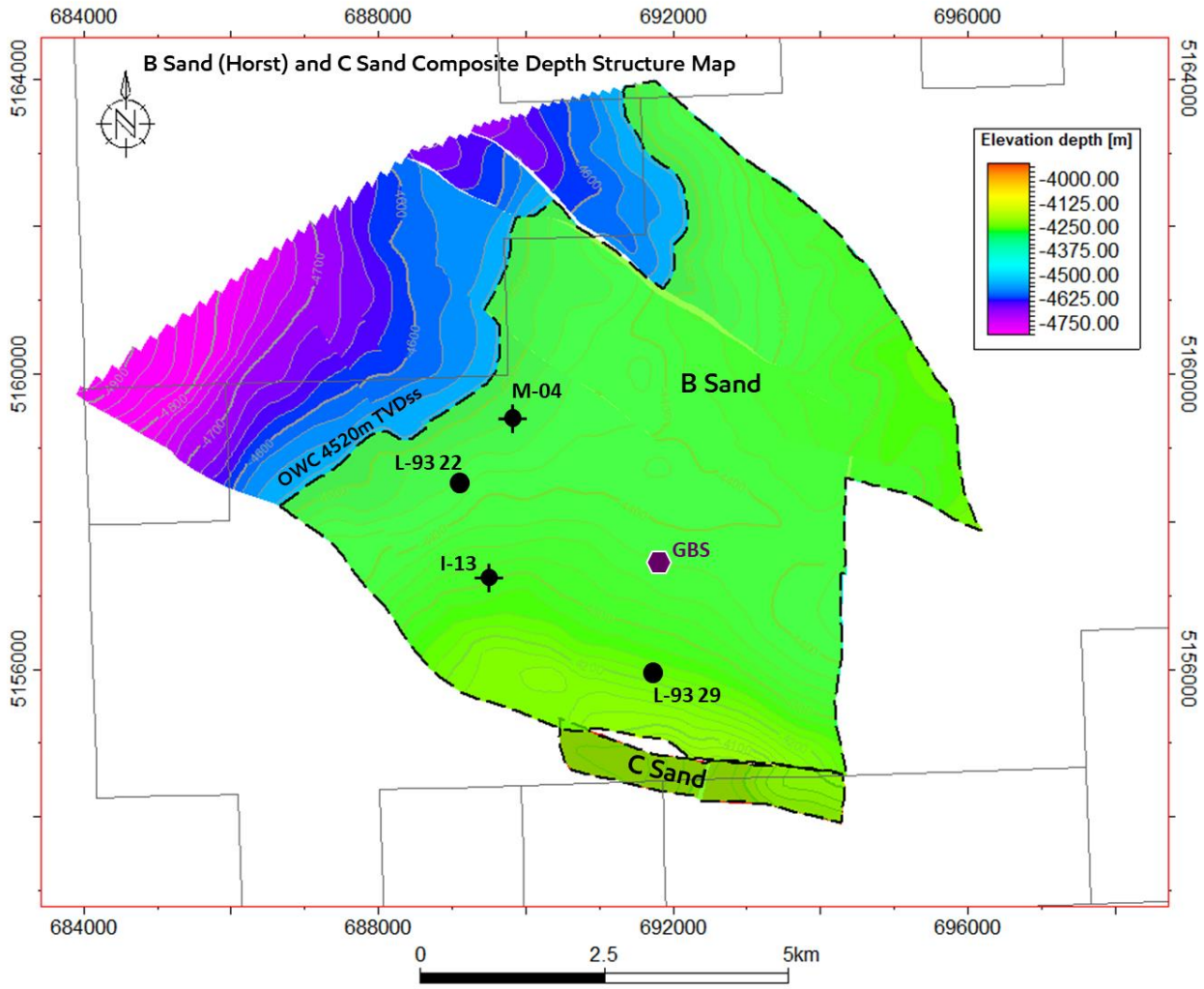


Figure 2-35: Top B Sand structure map
Outlines the proposed hydrocarbon accumulation connected to the B Sand horst block.

The combination of faulting and an overall sandy Jeanne d'Arc Formation means the juxtaposition relationships are an important consideration in the hydrocarbon accumulation and highlights the need to consider development of the Jeanne d'Arc Formation as a whole.

2.2 Geophysics

The following section includes a brief overview of the 2013 Hebron IsoMetrix Seismic Survey, synthetic seismograms used in the interpretation, interpretation strategy and resulting structure maps, and selected seismic cross sections showing the interpretation.

2.2.1 Seismic Surveys

The initial 3D survey over Hebron was acquired by PGS in 1997 and processed by CGG using state of the art techniques for the time. These data were successfully reprocessed in 2006 by Veritas and formed the

basis of the Hebron Project Development Plan. The data was reprocessed again in 2012 by CGG as a precursor to the acquisition and processing of the 2013 Hebron IsoMetrix survey.

The Hebron IsoMetrix survey was acquired in 2013 by Schlumberger (WesternGeco) as a new 4D baseline survey for the Hebron Asset. It is a streamer multicomponent survey with dense channel spacing. 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 began in 2014 and was completed in 2015.

2.2.2 Processing and Interpretation of Seismic

Figure 2-36 shows the fold coverage of the 2013 IsoMetrix Survey input data with a full fold of 60. The full fold area is approximately 457 km^2 (excluding acquisition holes) and is outlined by the blue polygon. All data, including those at low fold were used for processing and imaging. The output of the 2013 Hebron TTI APSDM is extended to the boundary of fold coverage of 20 which is the red polygon. This is approximately 588 km^2.

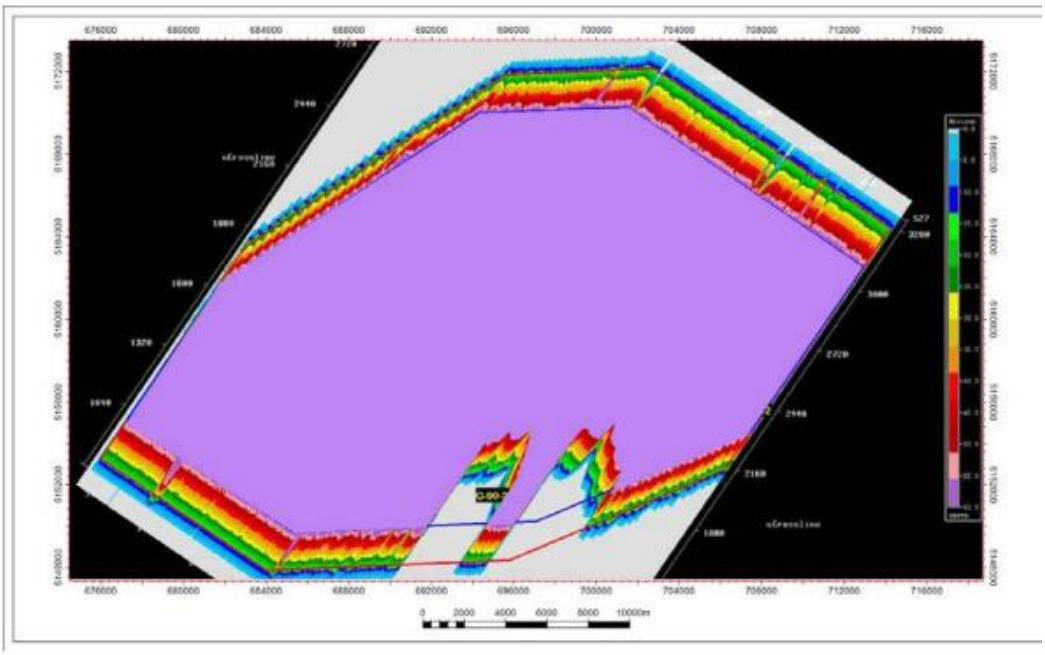


Figure 2-36: Fold coverage of the processing grid
Maximum fold in purple colour is 60

During the acquisition, pressure (P), acceleration in y (A_y) and z (A_z) are recorded. P and A_z were input into the conventional processing workflow which included 4 major stages:

1 Pre-processing
2 Velocity model building
3 Final Kirchhoff anisotropic pre-stack depth migration
4 Post-migration processing

2.2.3 Hebron Jeanne d'Arc Formation Seismic Interpretation

Seismic events were tied to the seismic data using synthetic seismograms where appropriate. In some instances, the tie may be degraded by poorer quality well log data, the deviated nature of some wells and lack of checkshot information. All synthetic seismograms were calculated using Petrel software from Schlumberger.

Well logs used in creation of the synthetics were edited to replace zones of bad data (for example shale washouts) and enhance the well to seismic tie where appropriate. Original checkshots are used where available. Well ties use the conventional Kirchhoff APSDM Full Stack with Amplitude Q Correction and were completed in time. The wavelet used for all synthetic seismograms is a 25Hz Ricker in Normal SEG polarity.

The following wells have synthetic seismograms:

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

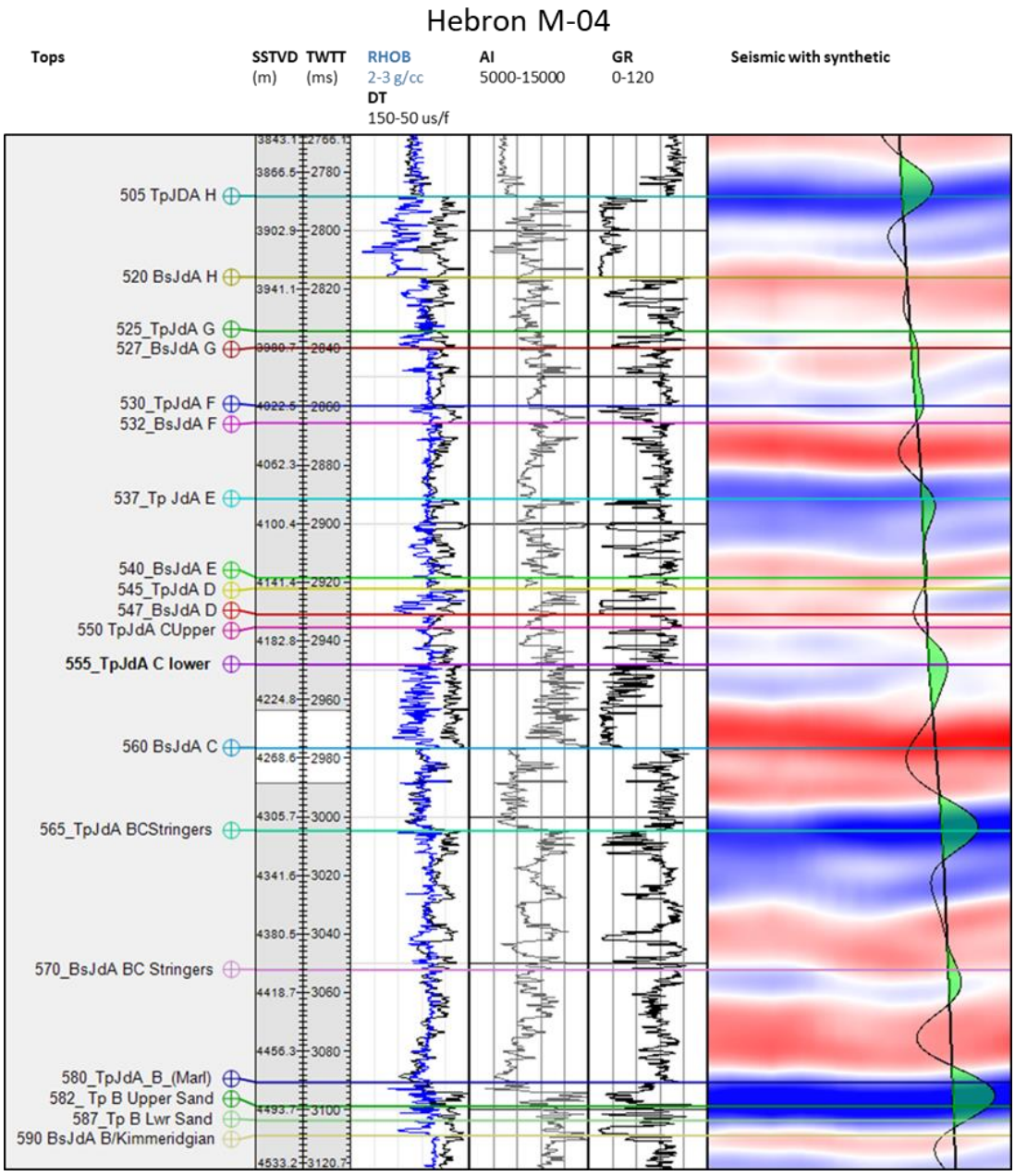


Figure 2-37: Synthetic Seismogram for Hebron M-04

SSTVD = True Vertical Depth Subsea; TWTT = Two Way Travel Time; RHOB = Bulk Density; DT= Delta Time (velocity); AI = Acoustic Impedance; GR = Gamma Ray

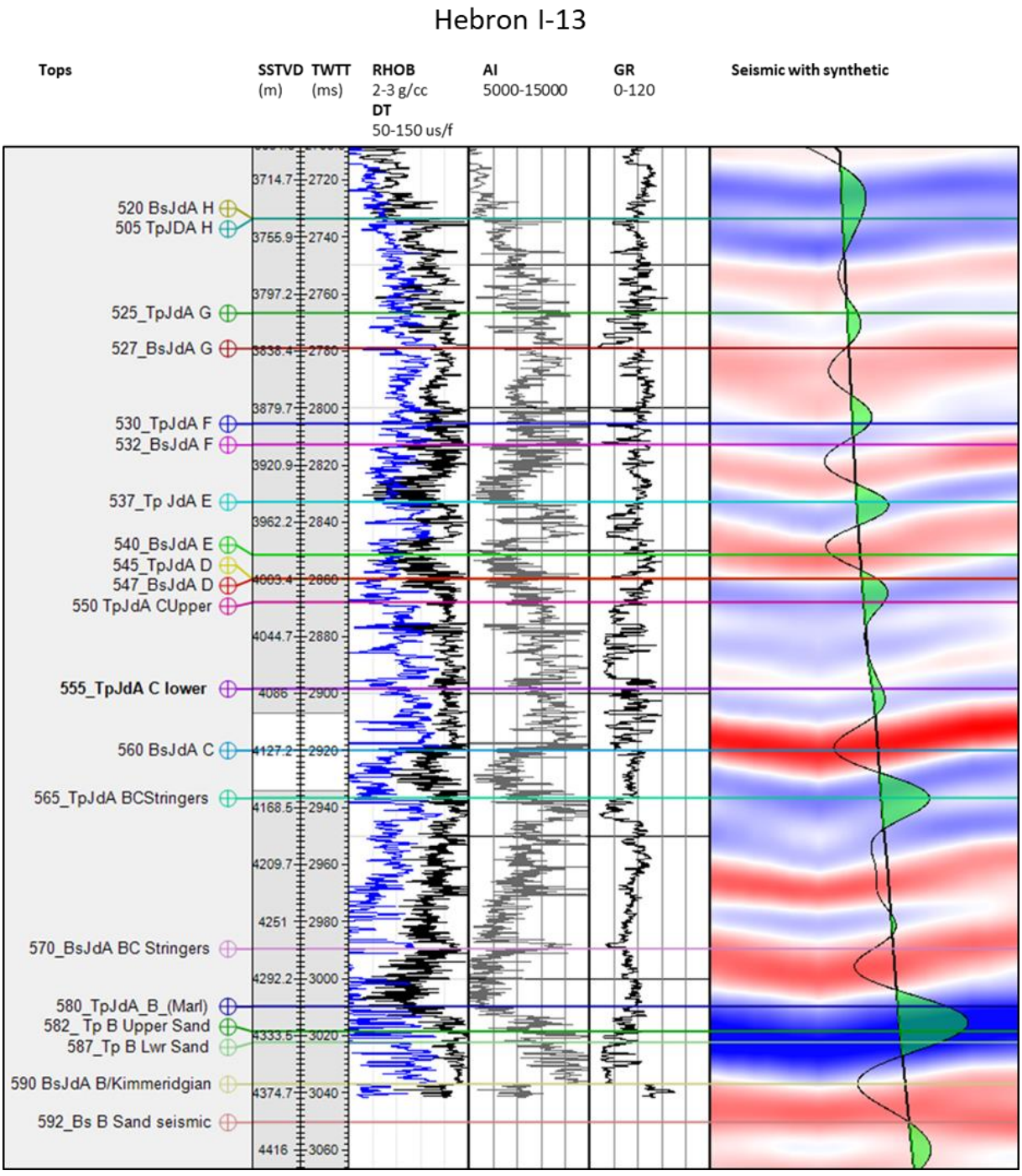


Figure 2-38: Synthetic Seismogram for Hebron I-13

SSTVD = True Vertical Depth Subsea; TWTT = Two Way Travel Time; RHOB = Bulk Density; DT= Delta Time (velocity); AI = Acoustic Impedance; GR = Gamma Ray

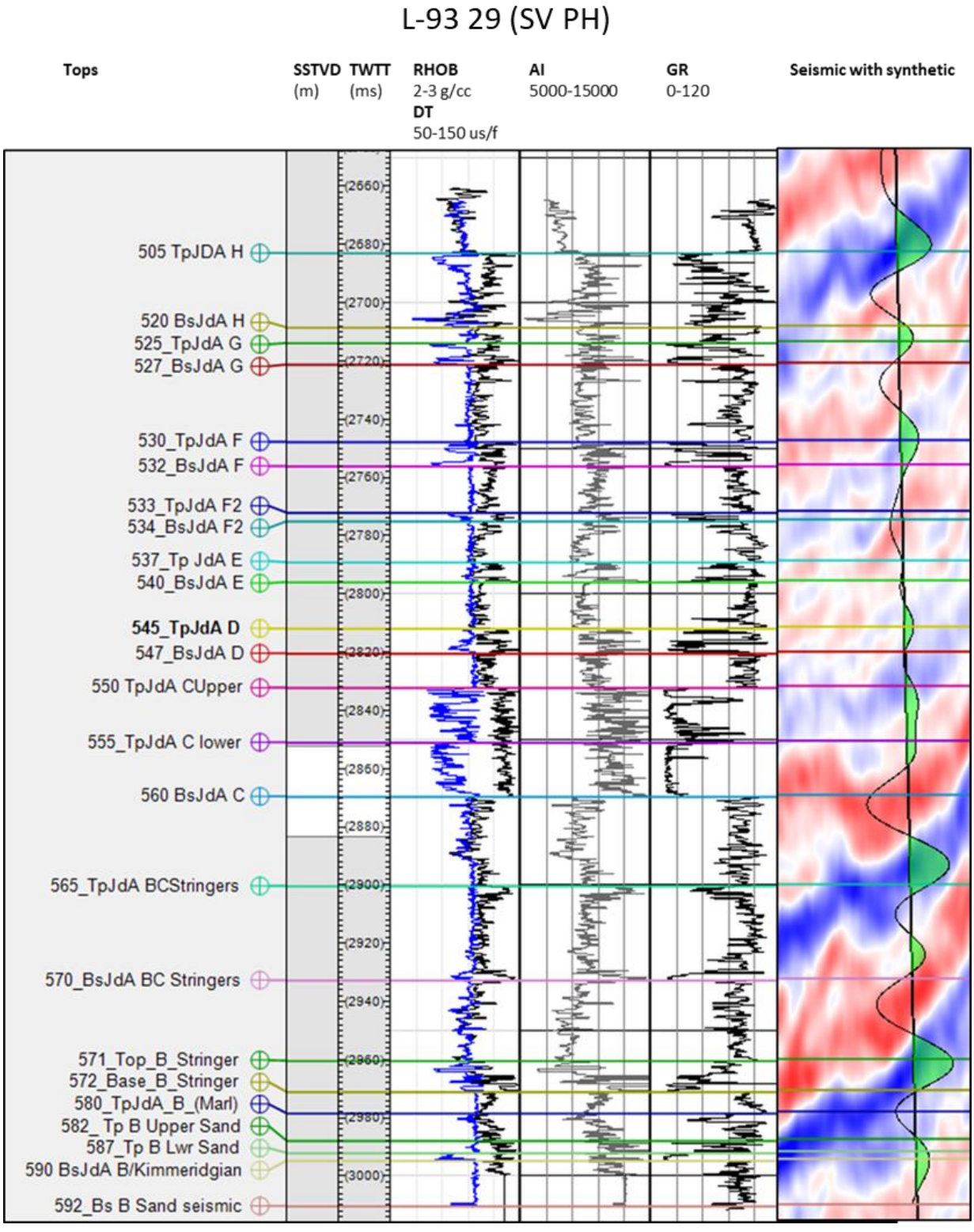


Figure 2-39: Synthetic Seismogram for L-93 29

SSTVD = True Vertical Depth Subsea; TWTT = Two Way Travel Time; RHOB = Bulk Density; DT= Delta Time (velocity); AI = Acoustic Impedance; GR = Gamma Ray

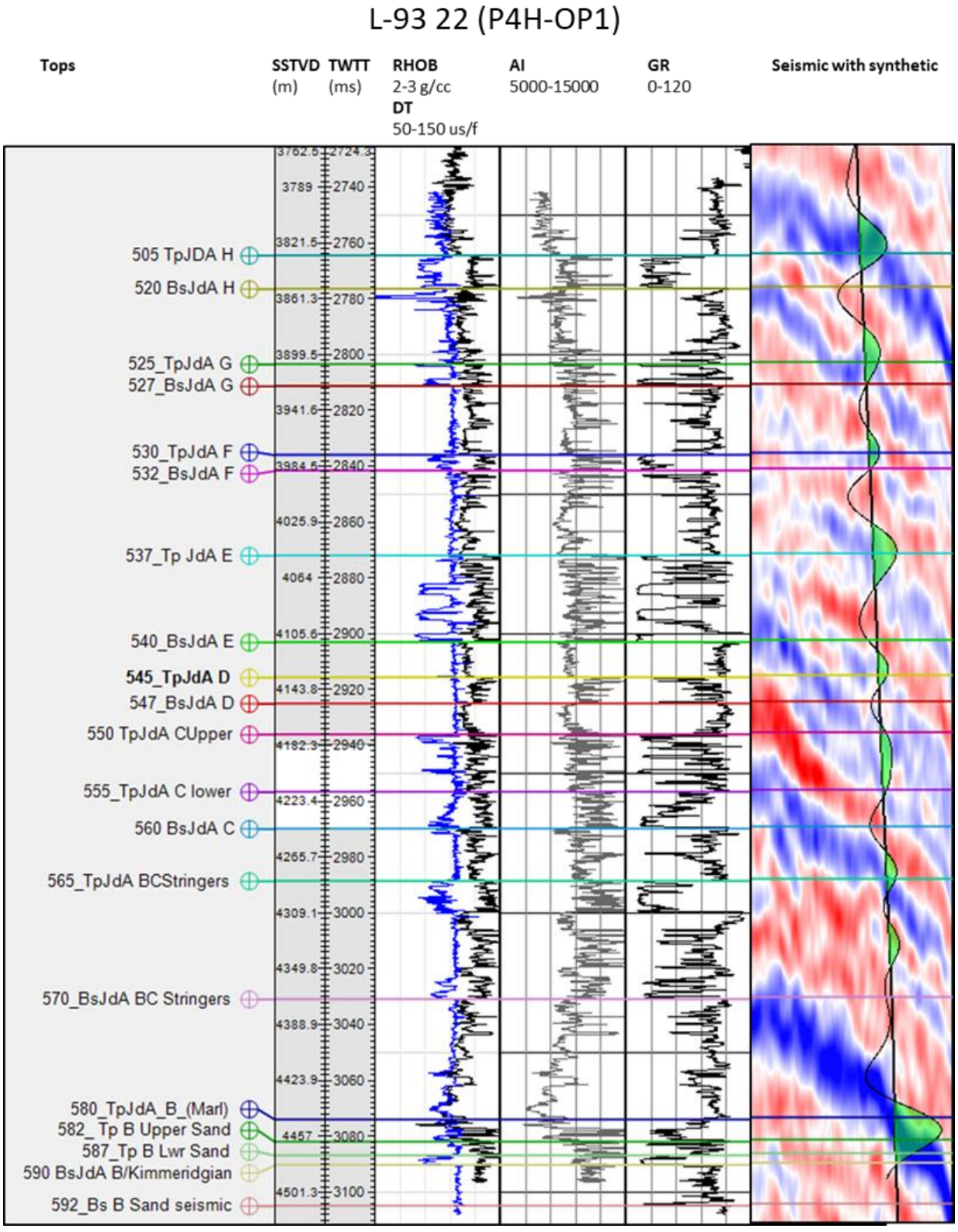


Figure 2-40: Synthetic Seismogram for L-93 22

SSTVD = True Vertical Depth Subsea; TWTT = Two Way Travel Time; RHOB = Bulk Density; DT= Delta Time (velocity); AI = Acoustic Impedance; GR = Gamma Ray

Seismic interpretation of the Jeanne d'Arc Formation was updated to integrate the most recent wells: L-93 22, L-93 29, L-93 30 and L-93 30z. In addition to incorporating new well data, a derivative volume from the seismic data set was utilized. The DSR volume is shaped to an impedance spectrum and then rotated to quadrature to generate a bandlimited impedance. This compensates for apparent frequency changes with steep dips.

Key horizons and major faults were interpreted across the Hebron Horst and surrounding fault blocks. Features such as local stratigraphic horizons or small throw faults were mapped where appropriated. Mapping of the sands within the Jeanne d'Arc Formation was primarily completed on the DSR volume. The H and C sands are mapped over the horst and surrounding fault blocks and the top and base is resolvable. The top of both sands is an S crossing whereas the base is a Z crossing. The E Sand is only mapped over a portion of the horst block. The top is mapped on an S crossing and the base is mapped on a Z crossing. The G and F sands are more difficult to map but in general, the top is an S crossing and the base is a Z crossing. The top B Sand is mapped as an S crossing but the base can below seismic resolution. In areas where the sand is thicker such as I-13, it is a Z crossing. Top structure maps based on the seismic interpretation are shown in the figures below.

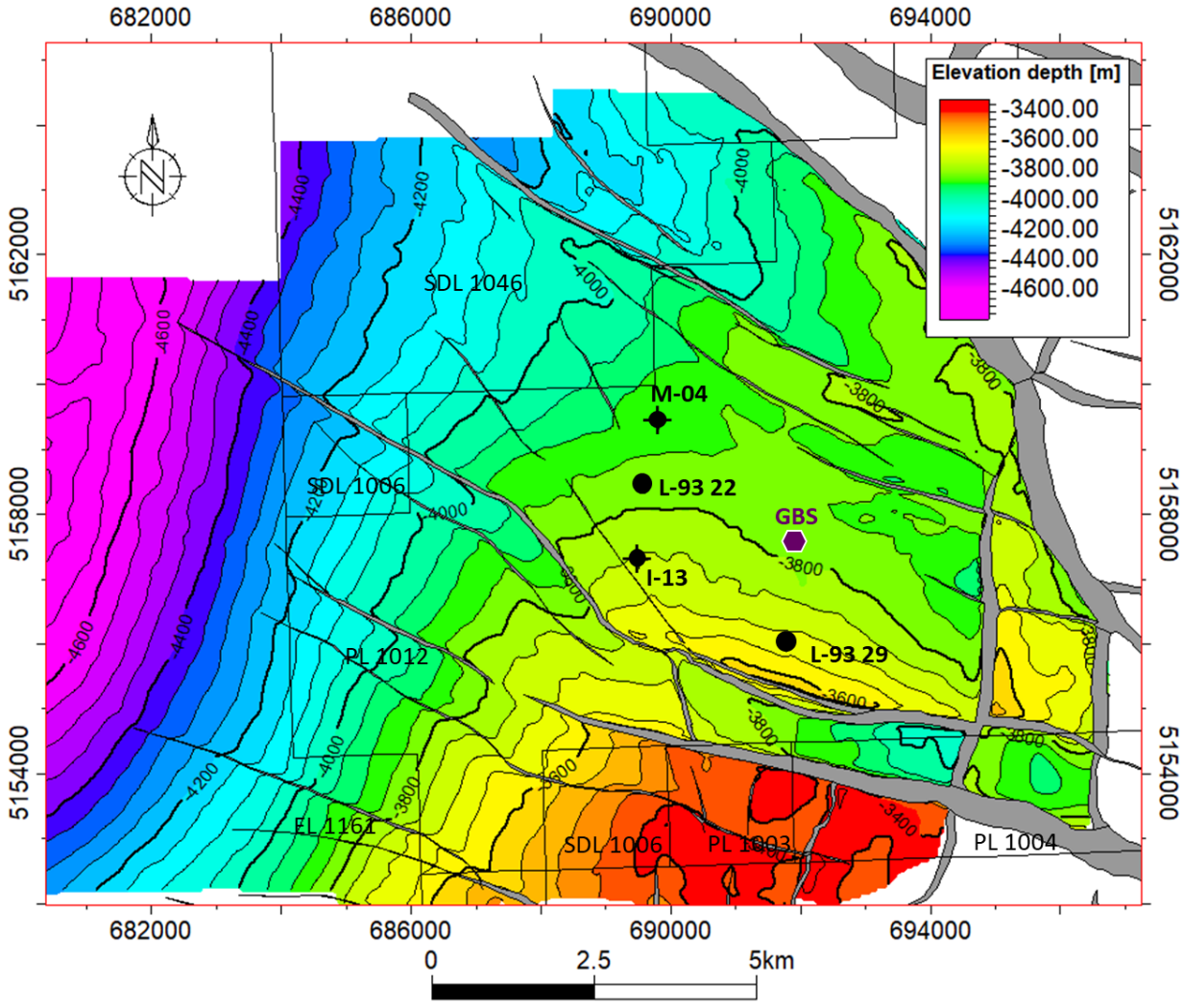


Figure 2-41: Top H Sand structure map

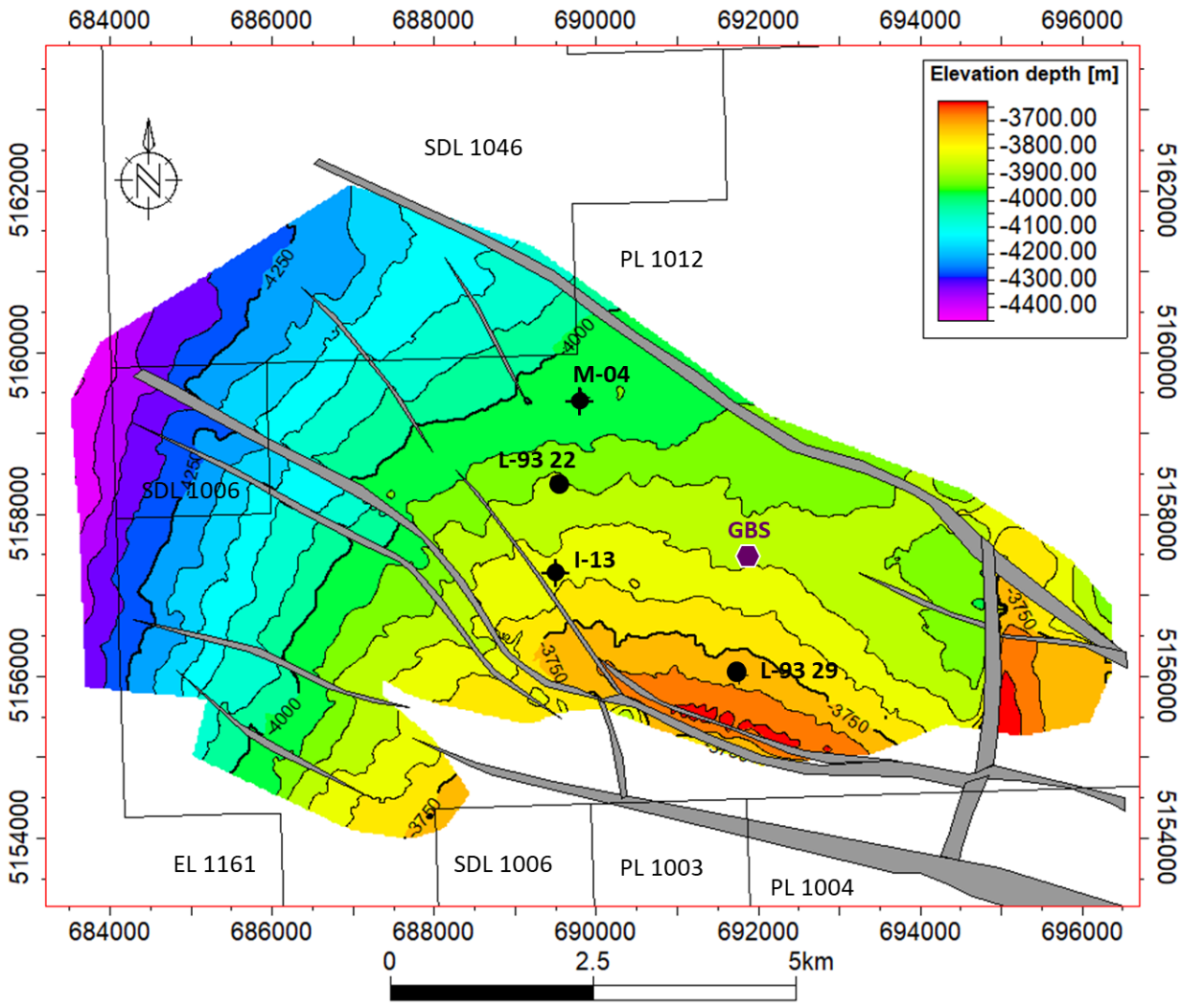


Figure 2-42: Top G Sand structure map

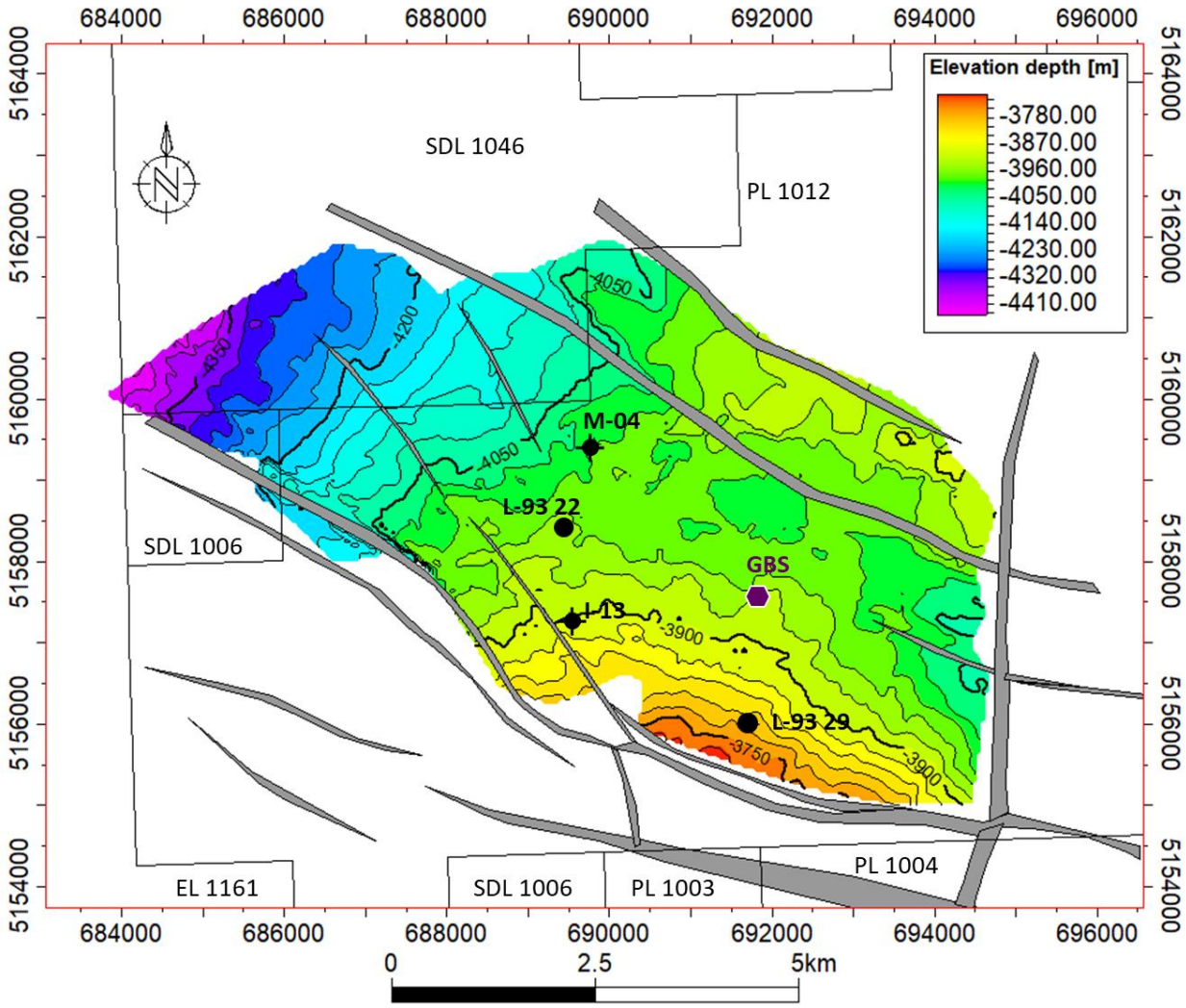


Figure 2-43: Top F Sand structure map

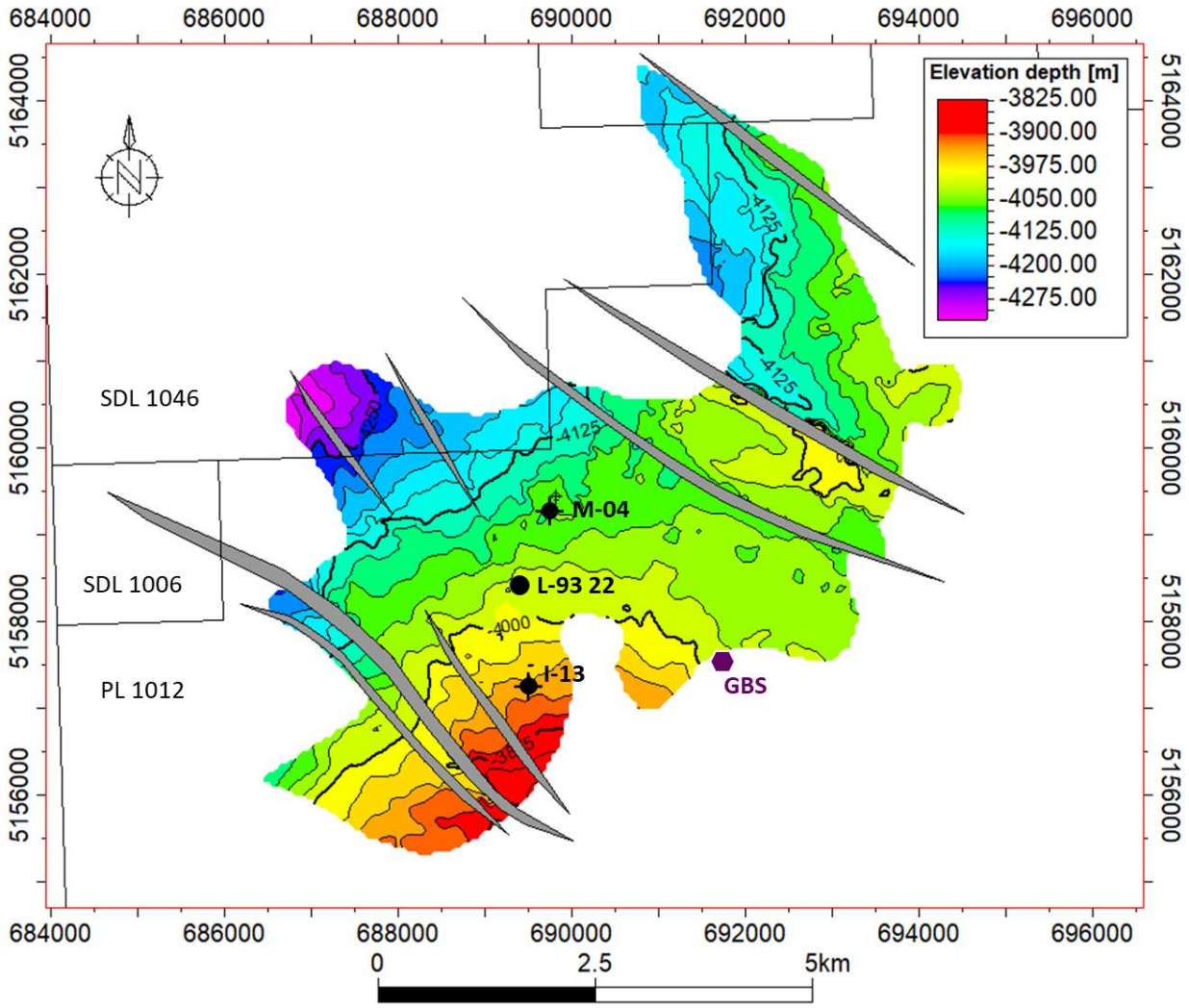


Figure 2-44: Top E Sand structure map.

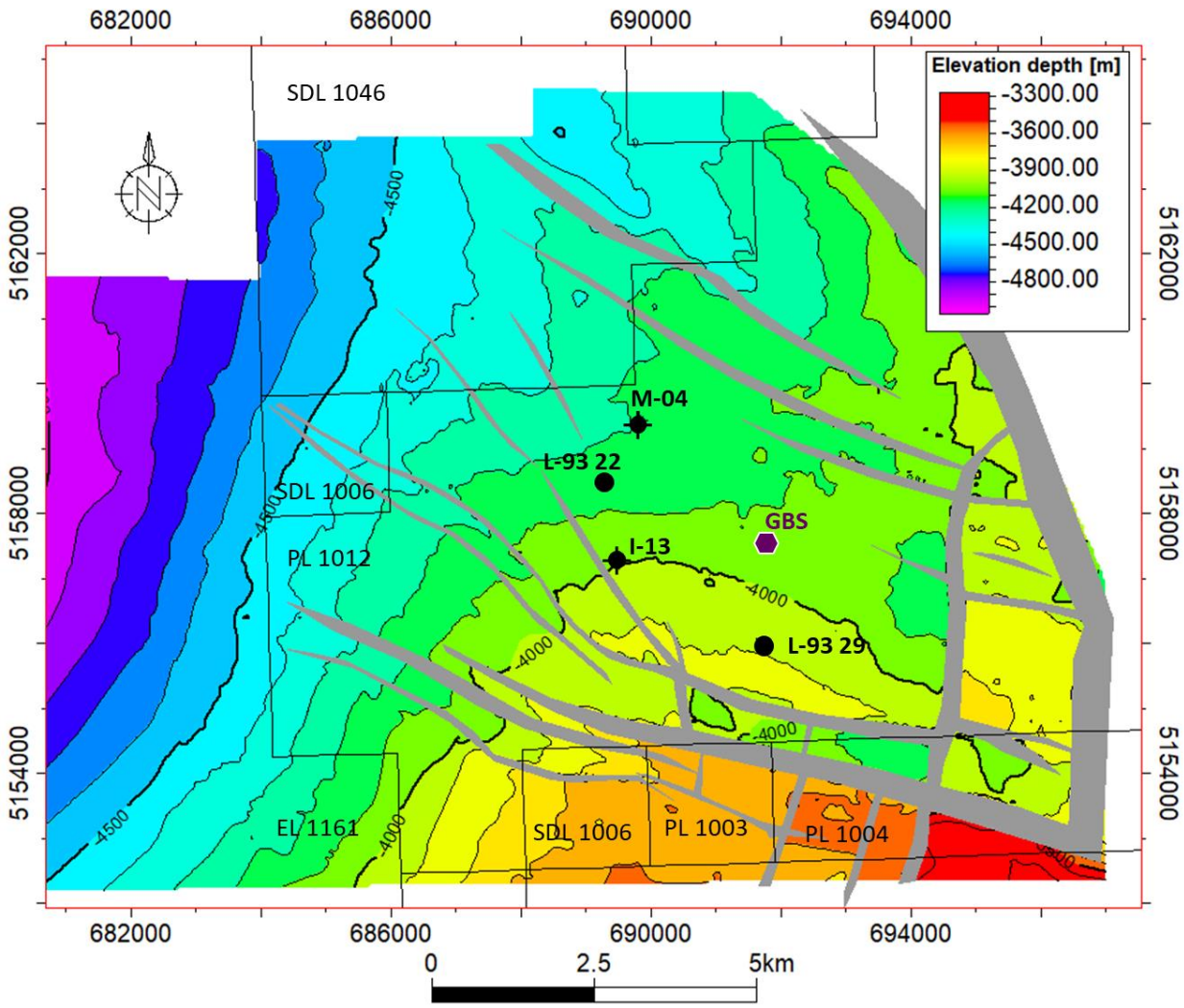


Figure 2-45: Top C Sand structure map.

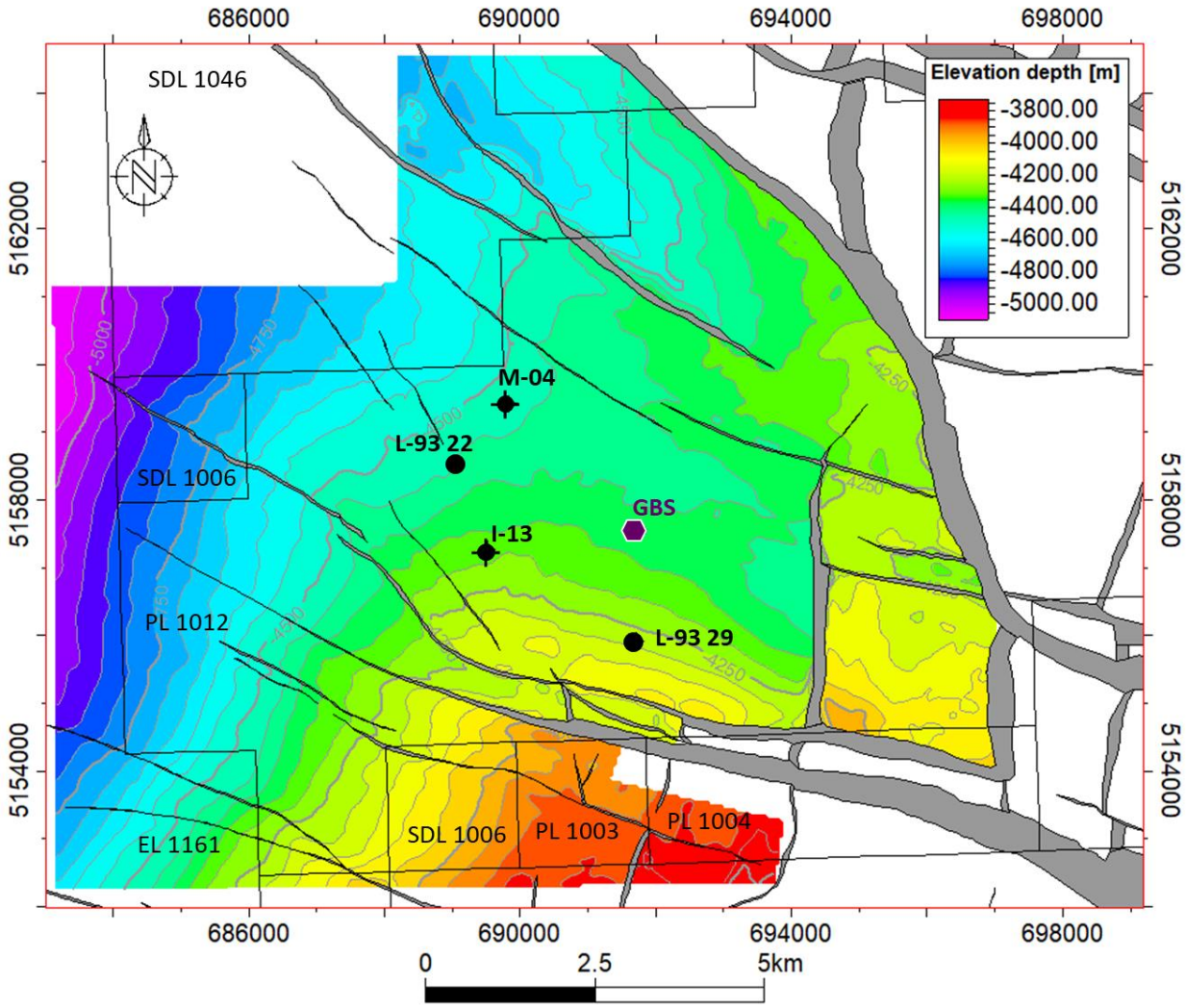


Figure 2-46: Top B Sand structure map

Seismic sections showing the interpretation of the Jeanne d'Arc Formation horizons and faults are shown below.

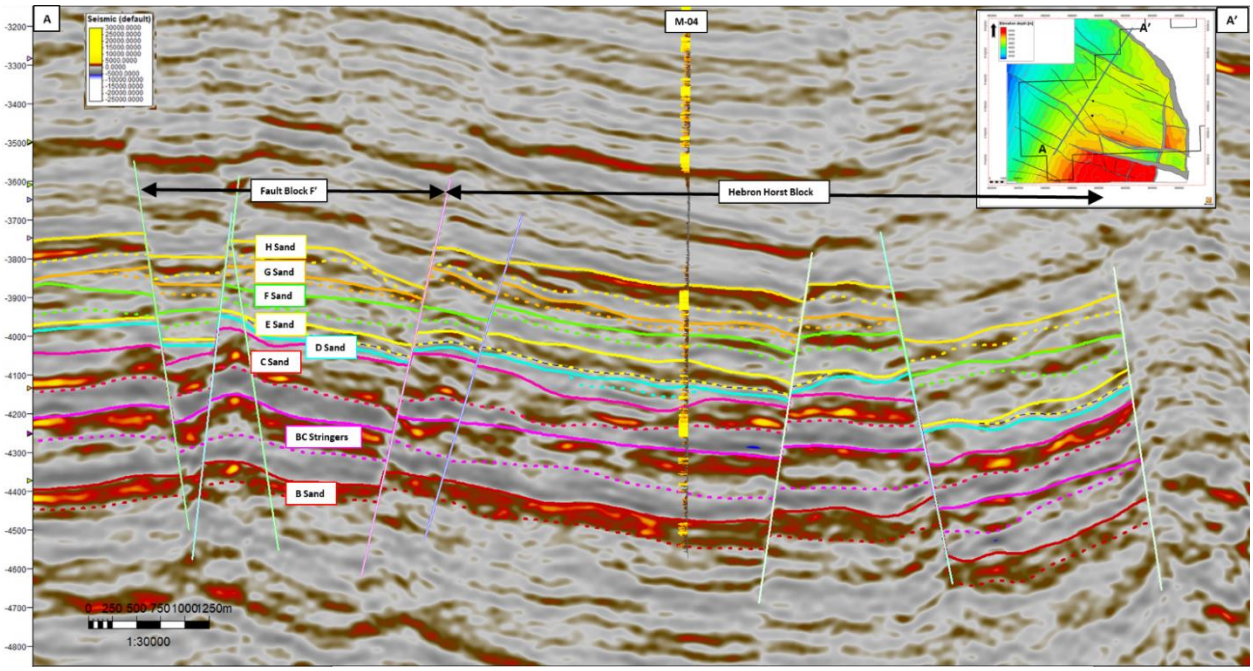


Figure 2-47: Cross section A-A' showing Jeanne d'Arc Formation horizon and fault interpretation on DSR volume

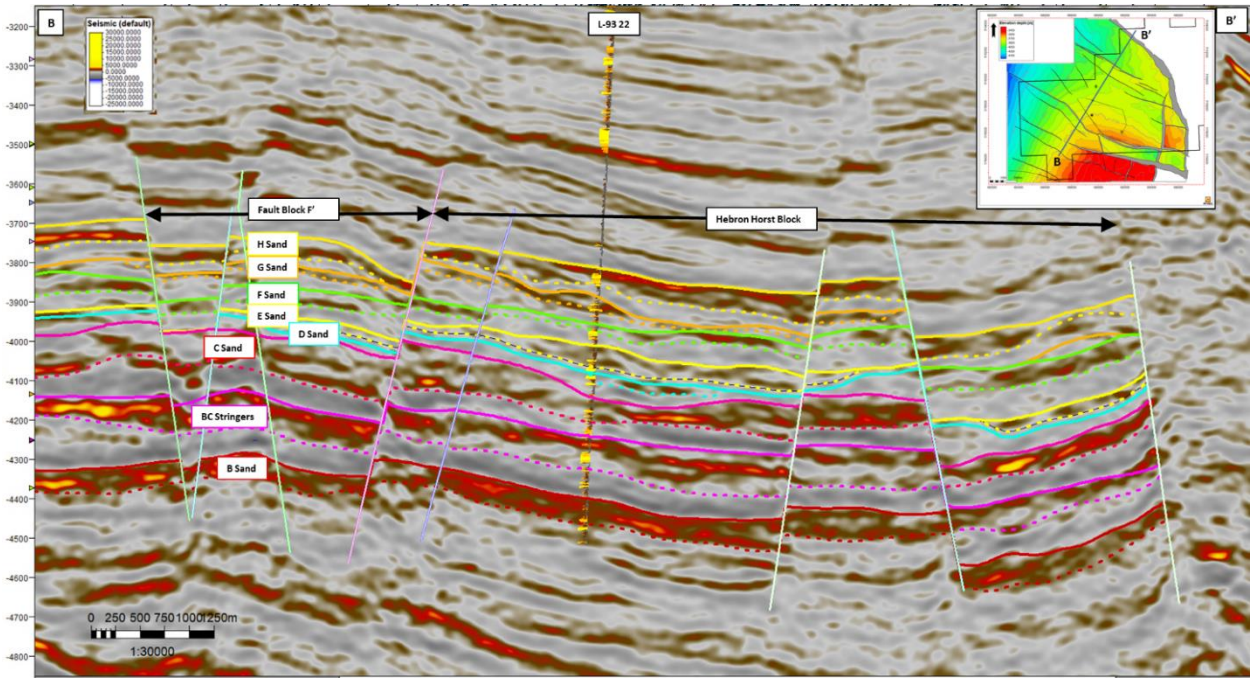


Figure 2-48: Cross section B-B' showing Jeanne d'Arc Formation horizon and fault interpretation on DSR volume

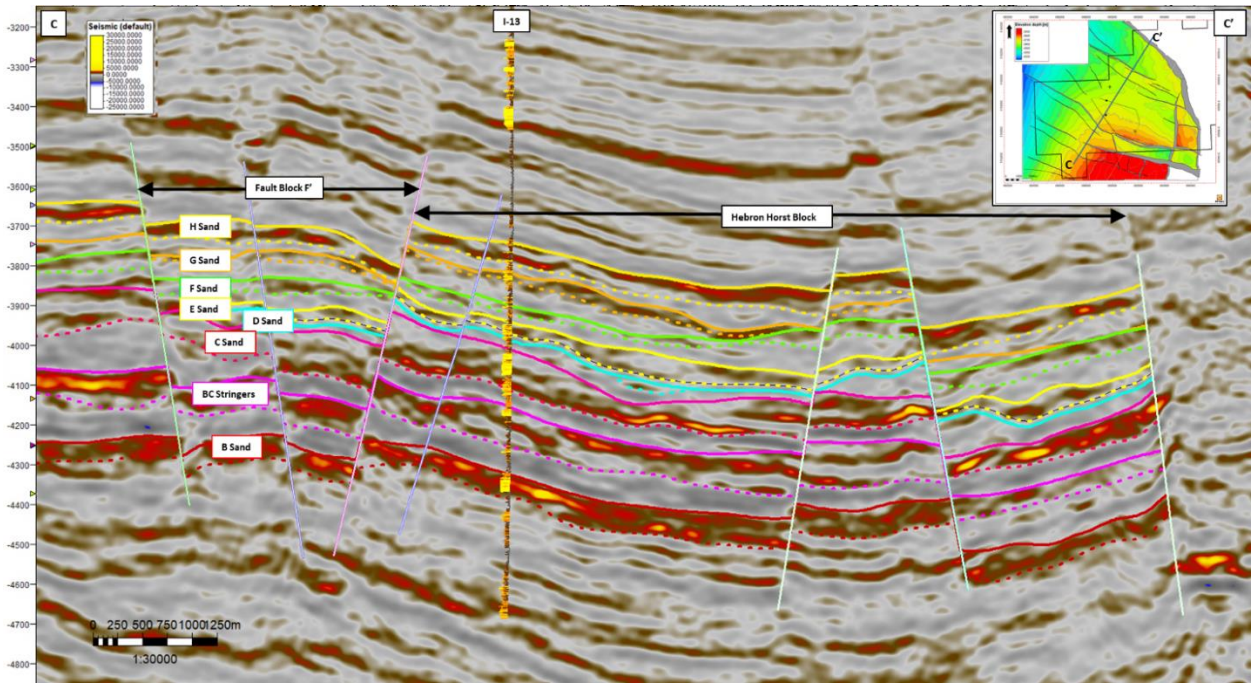


Figure 2-49: Cross section C-C' showing Jeanne d'Arc Formation horizon and fault interpretation on DSR volume

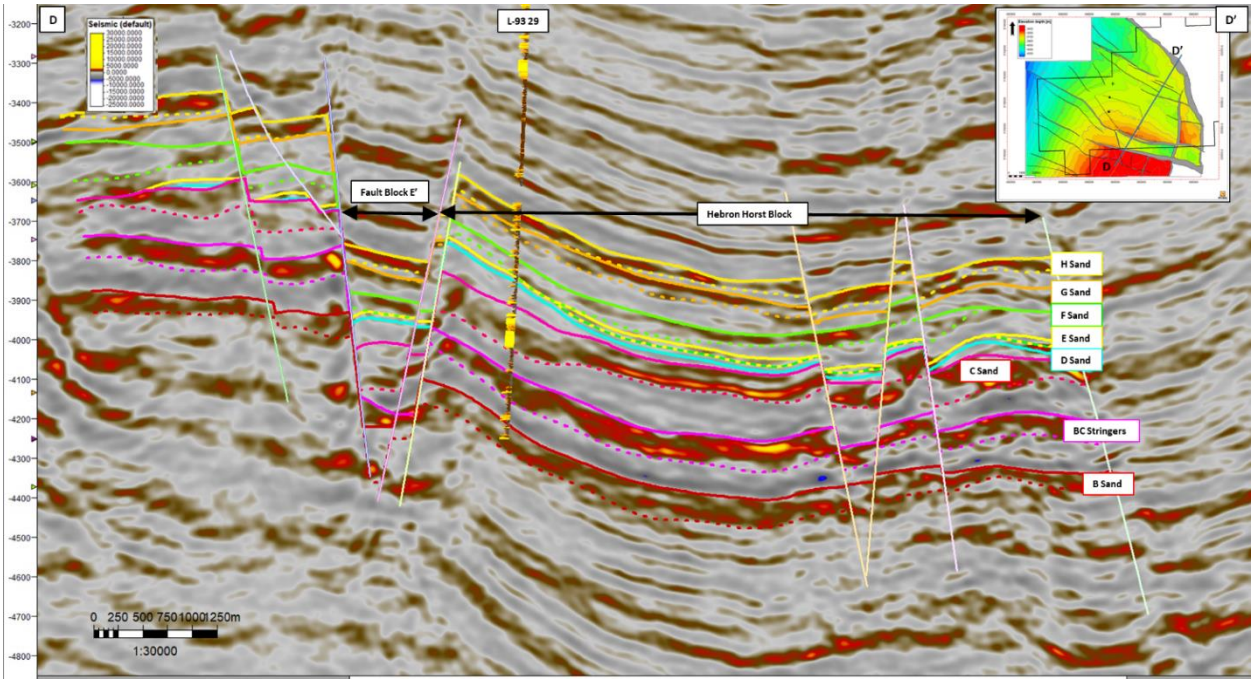


Figure 2-50: Cross section D-D' showing Jeanne d'Arc Formation horizon and fault interpretation on DSR volume

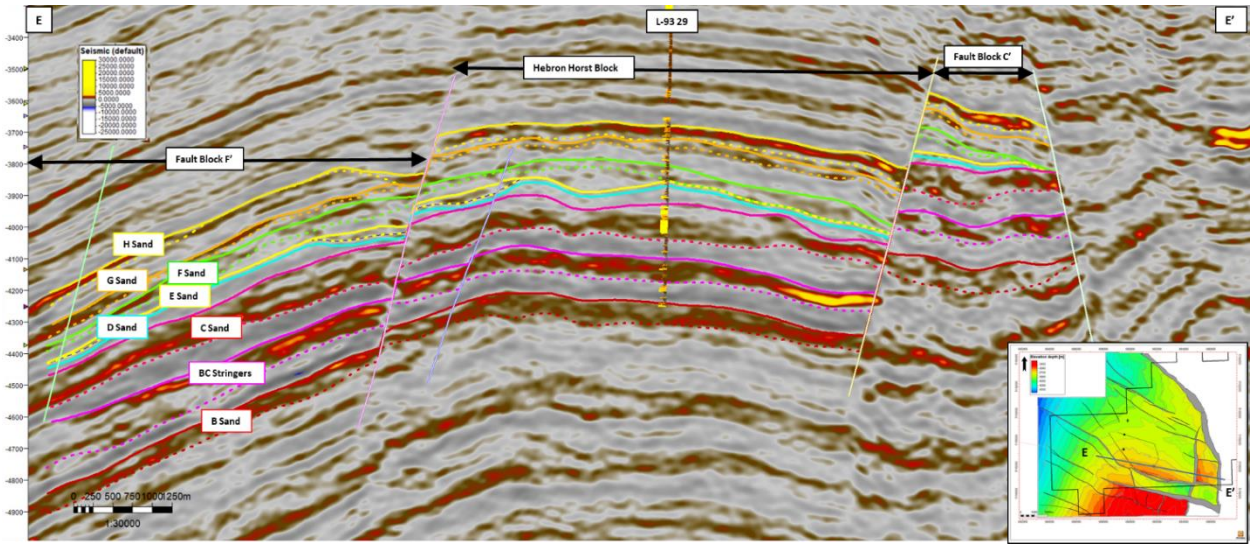


Figure 2-51: Cross section E-E' showing Jeanne d'Arc Formation horizon and fault interpretation on DSR volume

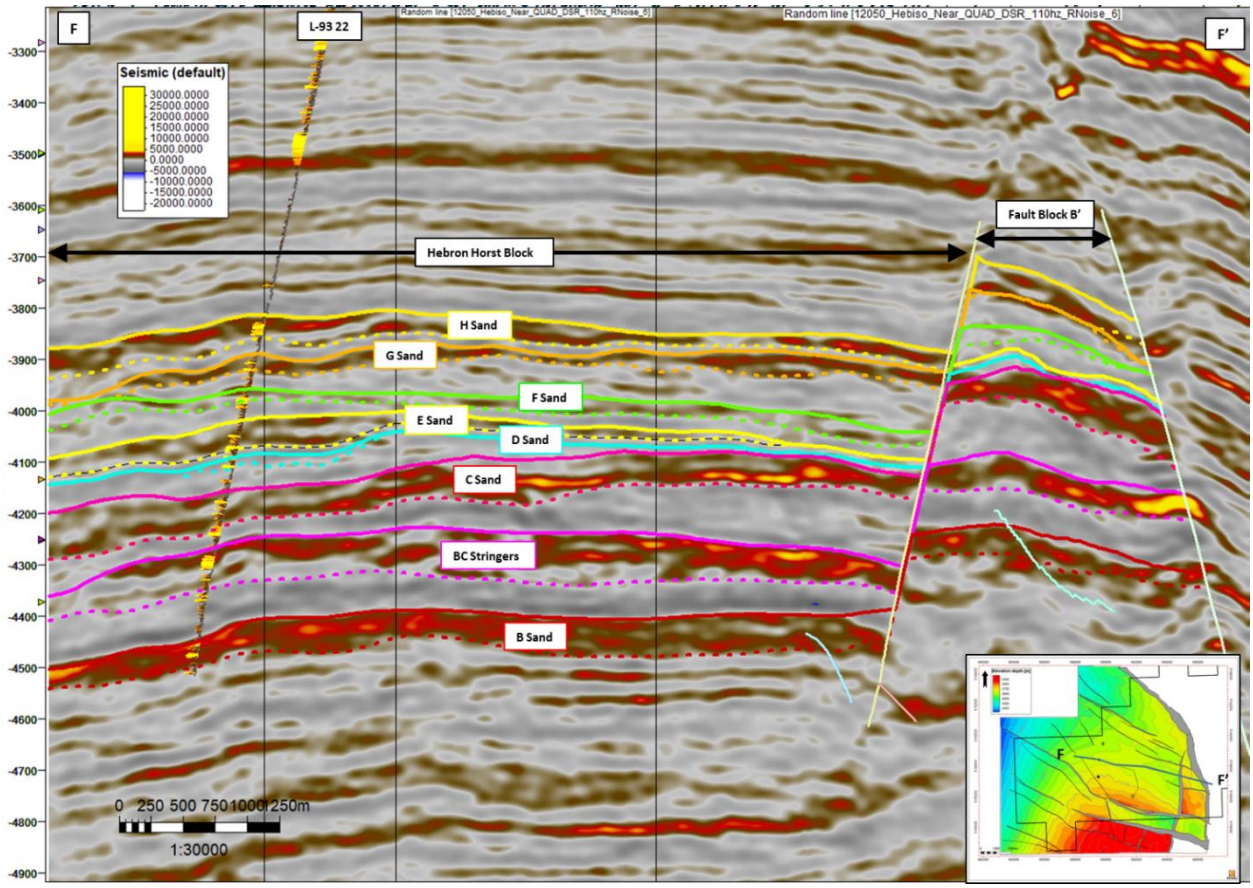


Figure 2-52: Cross section F-F' showing Jeanne d'Arc Formation horizon and fault interpretation on DSR volume

The mapped seismic surfaces deviate from the well log based tops; however, there is no systematic pattern in the deviation, either by well or by interval. Some of the differences are due to difficulties in discerning sandstone from siltstone and yet others are due to local variations in the velocity model. In

general, a 1% depth error is not unreasonable and at the depth of the Jeanne d'Arc Formation, that equals ~40-50m.

Table 2-1: Table of deviations from seismic interpretation and well log tops. Negative values mean the well top is deeper than the seismic, positive values indicate shallower

	Top H	Base H	Top G	Base G	Top F	Base F	Top E	Base E	Top D	Base D	Top C	Base C	Top BC	Base BC	Top B	Base B
M-04	-14	-7	6	5	-29	-9	-22	-2	5	5	-4	-34	-20	2	-3	30
I-13	0	7	10	-9	11	18	0	-8	-11	-11	-8	-11	-4	-13	15	11
L-93 22	-14	2	-17	10	-21	-13	-29	-8	-15	-15	-19	17	-15	-22	3	22
L-93 29	23	22	10	11	23	21	3	-13	-26	-26	-13	11	14	-39	0	30
Average	-1.25	6	2.25	4	-4	4.25	-12	-7.75	-11.75	-11.75	-11	-4.25	-6.25	-18	3.75	23.25

2.3 Petrophysics

The section that follows will outline the available petrophysical data, workflows and summaries used by the Operator to evaluate the Jeanne d'Arc Formation.

2.3.1 Petrophysical Data

Comprehensive wireline log data sets are available for Hebron I-13, Hebron M-04, West Ben Nevis B-75, and North Trinity H-71 (*i.e.* GR/RES/DEN/NET/Sonic). The more modern Hebron M-04 datasets include wireline nuclear magnetic resonance (NMR) data and oil-based mud borehole images (OBMI).

Recently drilled development/pilot wells have comprehensive LWD and wireline log data sets. The Hebron L-93 22 has LWD GR/RES/DEN/NEUT/Sonic/NMR in the 216mm hole section, as well as wireline dipole sonic (SonicScanner) and OBMI (QuantaGeo) in the 311mm hole section. The Hebron L-93 29 has LWD GR/RES/DEN/NEUT/Sonic in both the 311mm section and 216mm section.

Log data quality is challenged at times in the early exploration wells (Hebron I-13, West Ben Nevis B-75, North Trinity H-71), largely due to frequent borehole washouts related to water-based mud. Log data quality is significantly better in the later Jeanne d'Arc Formation penetrations.

2.3.1.1 Core Data

The Jeanne d'Arc Formation core dataset is comprised of whole core and rotary sidewall cores (RSWC) from North Trinity H-71, West Ben Nevis B-75, Hebron I-13, Hebron M-04, L-93 22, and L-93 29. Core data are primarily focused on the H and B sands of the JDA (Table 2-2). Routine core analyses (RCAL), including porosity, permeability, grain density, and Dean Stark saturation measurements, have been completed on the above-listed wells (Table 2-3). Additionally, a subset of these plugs have petrographic descriptions from thin sections and X-Ray Diffraction (XRD).

The overwhelming majority of core analytical data are routine analyses. There are some SCAL data available from the Hebron I-13 well, but reliability concerns exist around the results.

Table 2-2: Inventory of existing Jeanne d'Arc Formation core (whole core and RSWCs)

Well Name	Core Number	Formation Cored	JDA Sand	Cored Interval (m)	Core Cut (m)	Core Recovered (m)	Recovery (%)	# Boxes
North Trinity H-71	6	Jeanne d'Arc	JDA Sand	4376.00 - 4394.00	18.00	6.85	38.1	5
North Trinity H-71	7	Jeanne d'Arc	B Sand	4458.00 - 4466.00	8.00	8.00	100.0	7
North Trinity H-71	8	Jeanne d'Arc	B Sand	4466.00 - 4472.00	6.00	5.40	90.0	4
North Trinity H-71				JDA Total	32.00	20.25	63.3	16
West Ben Nevis B-75	6	Jeanne d'Arc	JDA Sand	4480.90 - 4494.50	13.6	13.6	100	15
Hebron I-13	5	Jeanne d'Arc	C Sand	4074.00 - 4083.40	9.40	6.60	70.2	5
Hebron I-13	6	Jeanne d'Arc	B Sand	4393.70 - 4409.90	16.20	16.20	100.0	12
Hebron I-13				JDA Total	25.60	22.80	89.1	17
Hebron M-04	4	Jeanne d'Arc	B Sand	4522.00 - 4587.00	65.00	64.35	99.0	51
Hebron M-04		Jeanne d'Arc RSWC	H Sand	3904.94 - 3957.0	41 samples			
		Jeanne d'Arc RSWC	D Sand	4178.40 - 4188.0	8 samples			
Hebron L-93 22	1	Jeanne d'Arc	H Sand	4826.3 - 4890.3	64.00	36.30	56.7	
Hebron L-93 29	RSWC	Jeanne d'Arc RSWC	H, G, F, C Sands	4255.4 - 4866.05	48 samples			

Table 2-3. Overview of JDA core analyses by well

	Analyses	M-04	I-13	B-75	H-71	L-93 22	L-93 29
Routine Core Analyses	**Routine Reservoir Properties** (# samples) • Porosity • Air permeability • Grain density • Dean Stark water saturation	H Sand: 41 (RSWC) D Sand: 8 (RSWC) B Sand: 69	C Sand: 29 B Sand: 31	JDA Sand (notional F sand): 25	B Sand: 45	H Sand: 98	H Sand: 13 (RSWC) G Sand: 5 (RSWC) F Sand: 4 (RSWC) C Sand: 12 (RSWC)
	Core Description • Sedimentary structures and textures, grain size, sorting, bedding	✓ *B sand only*	✓		✓	✓	✓
	Petrography • Thin section mineralogy, texture, point count data	✓ *B & H sands*	✓		✓	✓	✓
	X-ray Diffraction Analyses • Bulk mineral composition	✓ *B sand only*	✓		✓	✓	✓
Special Core Analyses	**Capillary Pressure and Relative Permeability Testing** • Primary drainage and imbibition cap pressure curves • Relative permeability curves		✓ *B sand only (reliability concerns)*			*Ongoing*	
	Electrical Property Measurements • Measurement of petrophysical parameters "n" (saturation exponent" and "m" (cementation exponent)		✓ *B sand only*			*Recently Completed*	

2.3.2 Calibration and Selection of Petrophysical Inputs

2.3.2.1 Overburden Compaction Factor

The JDA overburden corrections are derived from Hebron I-13 B Sand core tests and Terra Nova. Correction equations for porosity (Phi_ob) and permeability (Perm_ob) are *Phi_ob = 0.944*phi_ambient* and *Perm_ob = 0.876*perm_ambient*, respectively (Figure 2-53).

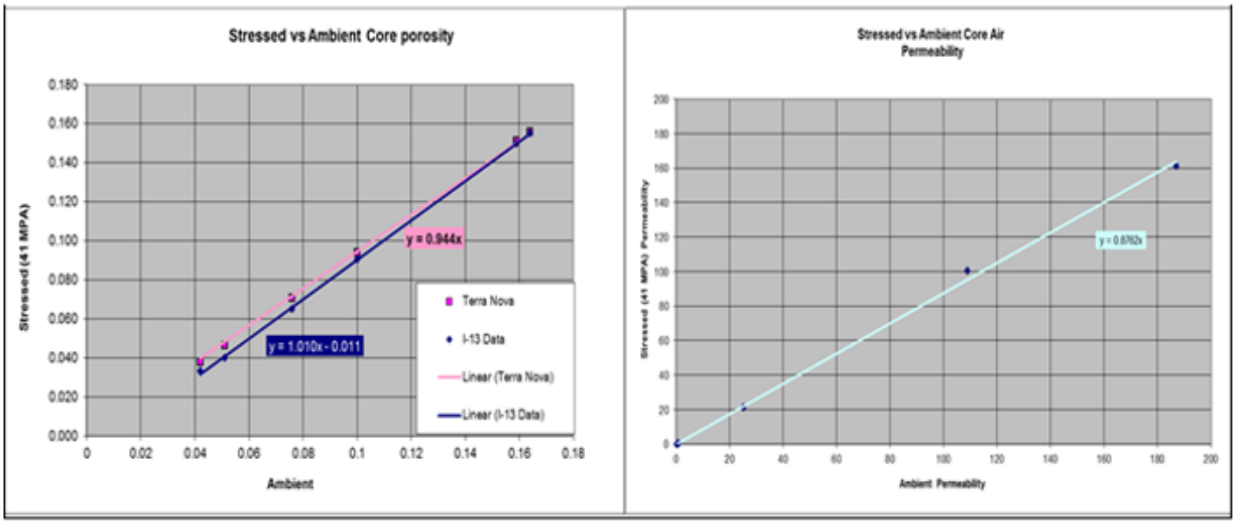


Figure 2-53. Overburden corrections for porosity and permeability.

2.3.2.2 Formation Water Resistivity

Based on available data, a formation water salinity of 72,000 ppm is interpreted for Jeanne d'Arc Formation sands (Terra Nova water samples). No water samples were collected in the Hebron M-04 well, but pressure tests indicated an oil water contact (OWC) that was consistent with log-derived OWC in the JDA H sand.

2.3.2.3 Electrical Properties for M and N

Currently, Archie "m" and "n" values are calibrated to Hebron I-13 B Sand SCAL data. However, there are reliability concerns surrounding the SCAL data, as outlined in section 4.3.3.1 of the *Hebron Application for Commercial Discovery Declaration (2013)*. Additional electrical property data have been collected from the L-93 22, and work is ongoing to integrate these new data and make appropriate adjustments to current Archie inputs for "m" and "n".

2.3.2.4 Petrophysical Methodology

Key components of existing Jeanne d'Arc Formation petrophysical models have been recently updated, incorporating newly acquired core analyses from L-93 22 and L-93 29. The primary updates to existing Jeanne d'Arc Formation workflows are related to porosity and permeability. Ongoing work is dedicated to incorporating new electrical property data to confirm petrophyscial inputs in current water saturation models.

2.3.2.5 Porosity (PHI) and Volume of Shale (VSH)

Recent updates have been implemented for Jeanne d'Arc Formation petrophysical workflows to incorporate newly acquired core data from L-93 22 and L-93 29. Volume of shale (VSH) is derived by frequency-plotting GR values over individual Jeanne d'Arc Formation sands, then using the 1% and 99% gamma ray values as inputs for clean sand (1%) and clean shale (99%) (Figure 2-54). Input values for GRclean and GRshale will vary slightly from zone-to-zone, but methodology remains consistent.

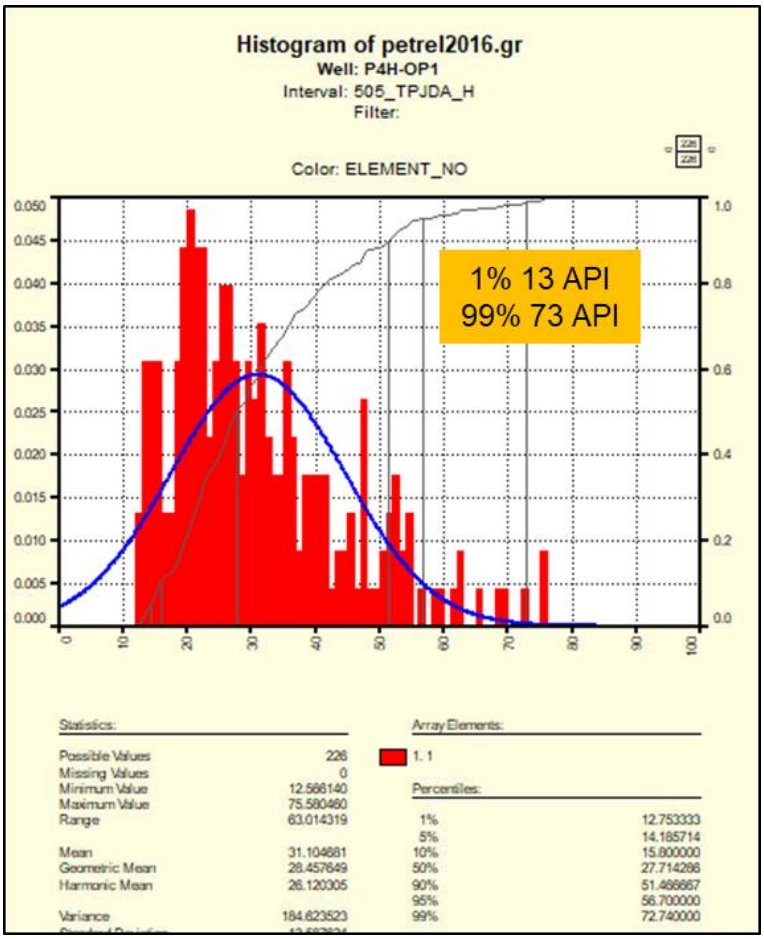


Figure 2-54 Frequency plot of L-93 22 H Sand gamma ray; API = American Petroleum Institute

The updated Jeanne d'Arc Formation porosity model utilizes a variable grain density approach to derive log-based total porosity. Ternary plots of XRD data (including L-93 29) were used to determine appropriate "grouping" of Jeanne d'Arc Formation sands based on mineralogy (Figure 2-55). Appropriate grain density values were derived using cross plots of log-measured bulk density data versus core porosity (Figure 2-56). Results indicate that 2665 kg/m^3 be used for Jeanne d'Arc Formation H – D sands, 2690 kg/m^3 for C sands, and 2673 kg/m^3 for B sands (Table 2-4).

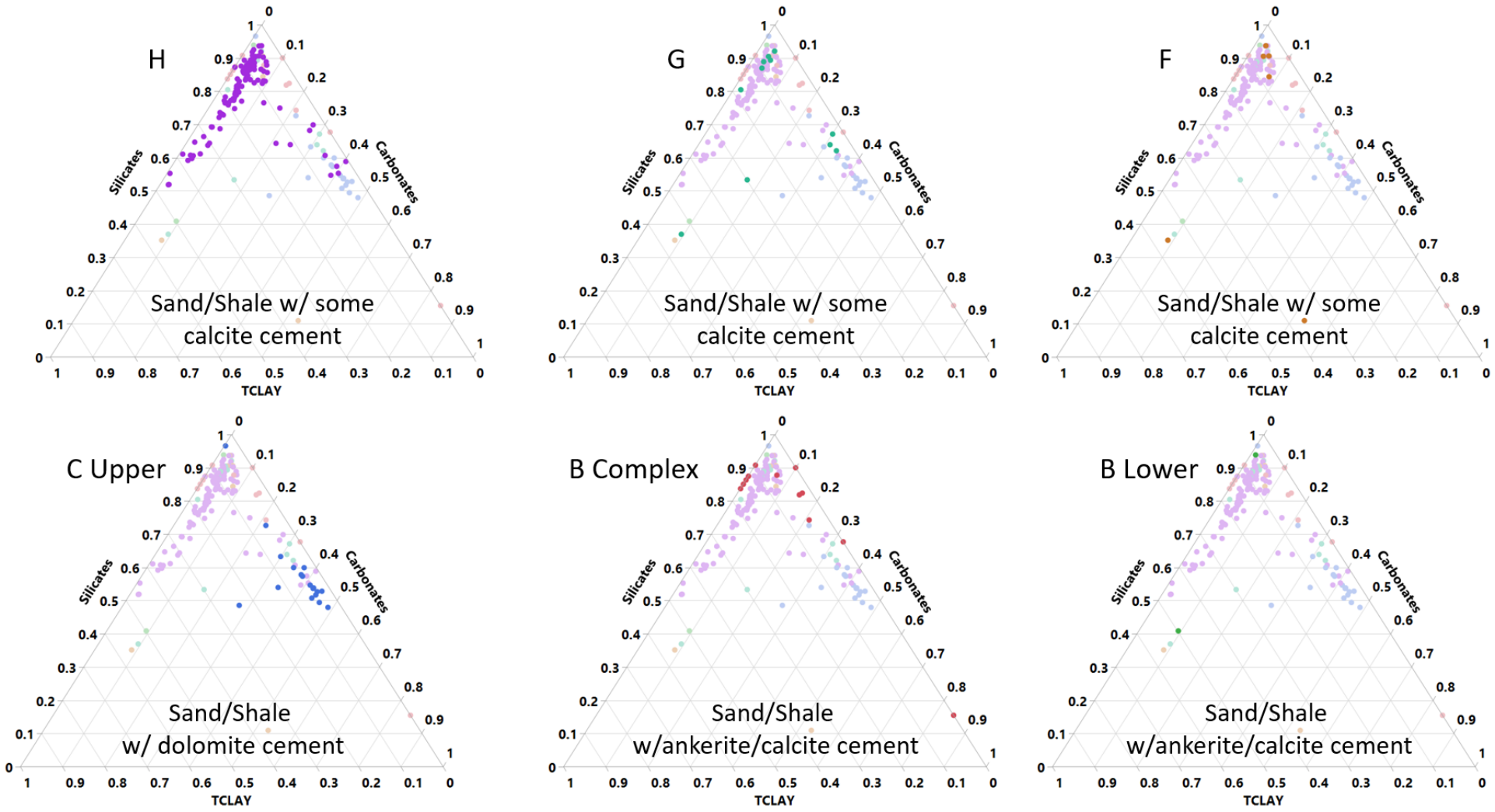


Figure 2-55: Ternary plots of JDA bulk XRD data
This approach was used to "group" mineralogically-similar JDA sands.

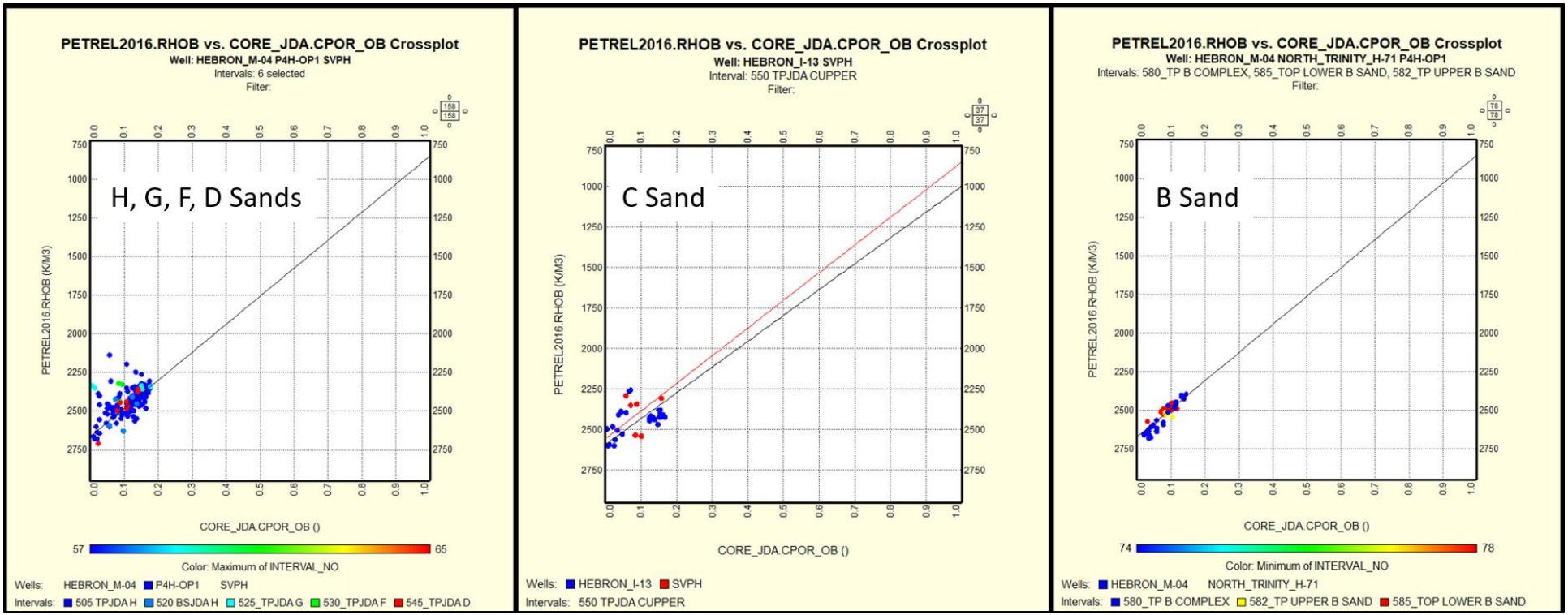


Figure 2-56: Cross plots of log bulk density versus core porosity
Regression lines fitted to the data were used to derive appropriate grain densities for JDA sands.

*Table 2-4: Grain (RHOG) and fluid (RHOFL) densities utilized in the updated JDA total porosity model. *RHOshl (shale bulk density) and *PHITshl (shale total porosity) were derived from L-93-22 in rocks >0.8 VSH.*

Interval	RHOG	RHOFL	RHOshl*	PHITshl*
Top H Sand – Top C Sand	2665	850	2578	0.05
Top C Sand – Top B Sands	2690	850	2578	0.05
B Sands	2673	850	2578	0.05

2.3.2.6 Water Saturation (Sw)

Methodology for deriving water saturation remains unchanged thus far for Jeanne d'Arc Formation sands. The primary model is Archie-based and assumes constant "m" (cementation exponent), "n" (saturation exponent), and salinity (72,000 ppm) for all sands. Newly acquired SCAL electrical property data from L-93 22 indicate an "m" of 2.49, "n" of 2.38, and "a" of 0.39, however, early indications are that resulting water saturation derived using these new inputs yields very small change from the existing Archie inputs for L-93 22 (Figure 2-57). These new results will continue to be evaluated for potential model updates for the Jeanne d'Arc Formation.

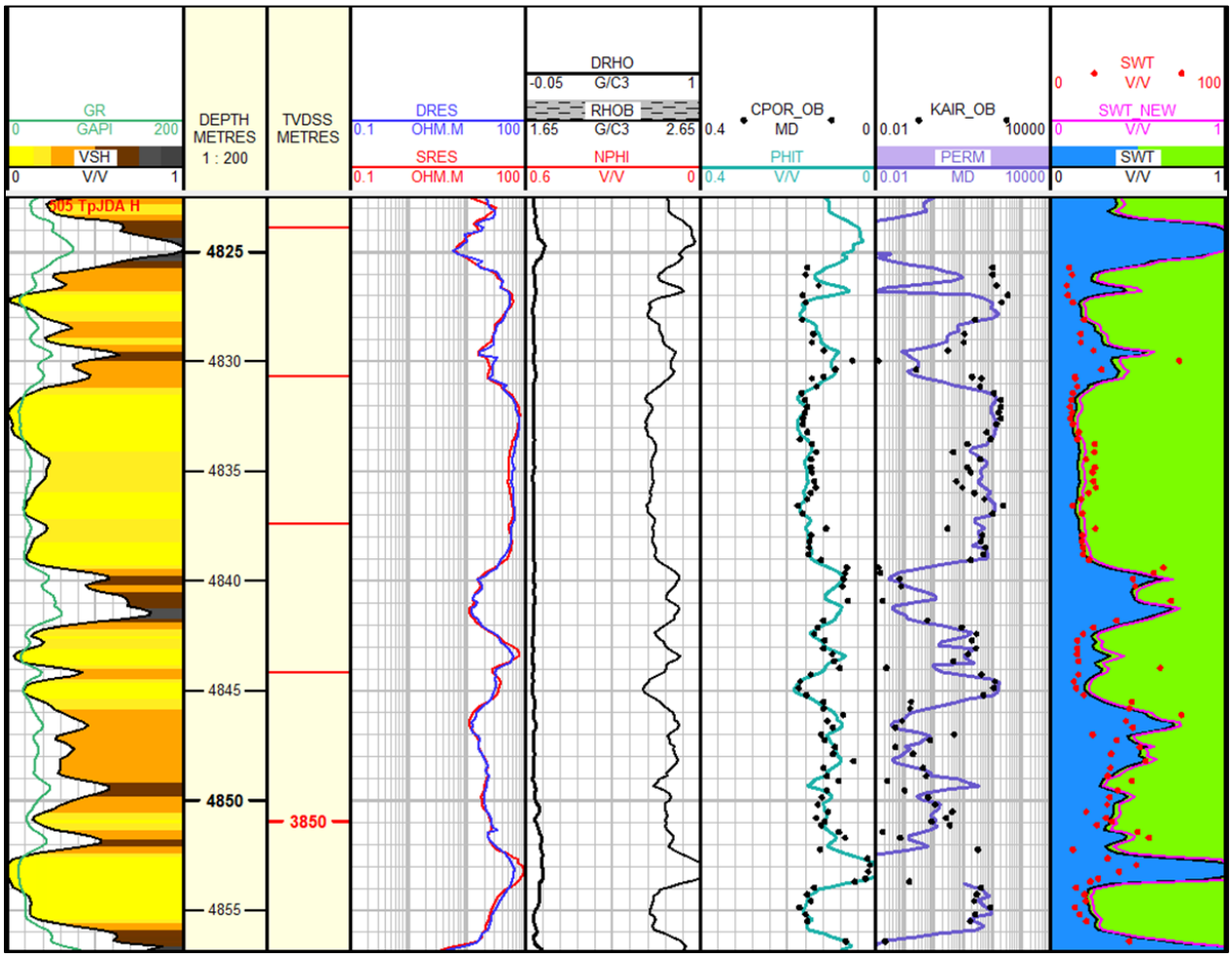


Figure 2-57: Log plot of L-93 22 showing existing Archie SWT interpretation versus updated SWT using newly acquired electrical property inputs.
From left to right, curve definitions are Gamma Ray (GR), Volume of Shale (VSH), measured depth (Depth), true vertical depth subsea (TVDSS), deep (DRES) and shallow (SRES) resistivity, bulk density correction (DRHO), bulk density (RHOB), neutron porosity (NPHI), core-derived total porosity at overburden (CPOR_OB), total porosity from bulk density (PHIT), core-derived air permeability at overburden (KAIR_OB), and log-derived permeability (PERM). The rightmost track illustrates existing Archie water saturation (SWT black curve shaded blue/green), core-derived Dean Stark saturation (SWT red dots), and Archie water saturation using updated L-93 22 electrical property data (SWT_NEW).

2.3.2.7 Permeability (K)

The Jeanne d'Arc Formation permeability model has been updated to incorporate newly acquired RCAL data from L-93 29. The current approach groups Jeanne d'Arc Formation sands of similar Permeability/ Porosity (K/PHI) trends to derive individual transforms that best fit available core data. The Jeanne d'Arc Formation F – C sands (excluding D), and D/B sands utilize a single K/PHI regression to derive log-based permeability from log-based total porosity. The H and G sands exhibit two apparent trends which could be discriminated using a combination of porosity and VSH constraints (Figure 2-58). If log-derived porosity in H and G sands is <0.05, the standard K/PHI regression fit illustrated by the black transform is assumed. If log-derived porosity is >0.05 but <0.16, the two transforms are discriminated using a VSH value of 0.13. Lower VSH rocks (<0.13) will utilize the red transform, whereas rocks >0.13 VSH utilize the standard (black) transform. Finally, rocks with porosity >0.165 utilize the standard (black) transform as it allows a reasonable fit to the few higher perm core plugs in the dataset.

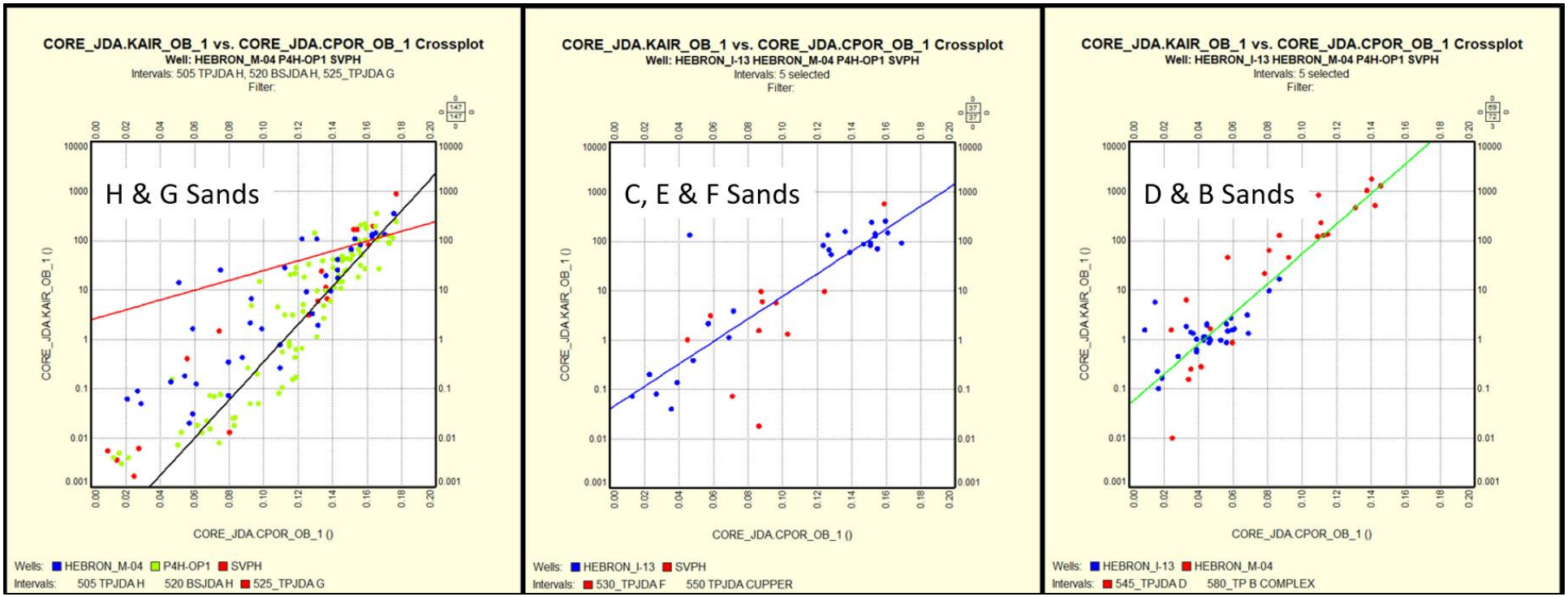


Figure 2-58 Cross plots of JDA core porosity and permeability used as the basis for the updated permeability models.

The H and G sand equations are as follows:

If PHIT <0.05 or >0.16, perm = 10**(-4.30391+38.3057*(PHIT))

If PHIT between 0.05 and 0.16 and VSH <0.13, perm = EXP(22.895*PHIT)*2.4533

If PHIT between 0.05 and 0.16 and VSH >0.13, perm = 10**(-4.30391 + 38.3057*(PHIT))

The F – C Sands, excluding D, equation is as follows:

K = 10**(-1.40548 + 22.8008*(PHIT))

The D/B sands equation is as follows:

K = 10**(-1.33 + 30.47*(PHIT))

2.3.2.8 Reservoir and Net Pay Cutoffs

The current approach to netting for pay is to use a permeability cutoff of 1mD. In circumstances where an OWC is penetrated in a producer, a water saturation cutoff of 0.55 is applied to remove those rocks from the pay total.

2.3.3 Petrophysical Summaries

Table 2-5: Summations for key JDA wells using petrophysical workflows outlined in Section 2.3. Average PHIT denotes porosity of net rock, Average SWT is Archie water saturation of net rock, and Average Perm is log-derived permeability of net rock.

WELL	INTERVAL	TVDSS_TOP	TVDSS_BASE	GROSS	NET	NET_TO_GROSS	Porosity Height	Permeability Height	Average PHIT	Average SWT	Average Perm
		METRES	METRES	METRES	METRES	M/M	(V/V)M	MDM	V/V	V/V	MD
HEBRON_I-13	H	3742.52	3742.52	0.00	0.00	0	0	0	0	0	0
HEBRON_I-13	G	3810.83	3836.36	25.53	6.70	0.262	0.889	358.796	0.133	0.335	53.57
HEBRON_I-13	F	3890.86	3906.01	15.14	0.00	0	0	0	0	0	0
HEBRON_I-13	E	3947.37	3985.60	38.23	1.52	0.04	0.114	3.368	0.075	0.305	2.213
HEBRON_I-13	D	NP	NP	NP	NP	NP	NP	NP	NP	NP	NP
HEBRON_I-13	C	4019.88	4126.96	107.08	20.37	0.19	2.253	660.476	0.111	1	32.42
HEBRON_I-13	BC Stringers	4161.51	4270.38	108.87	5.63	0.052	0.523	217.003	0.093	0.693	38.561
HEBRON_I-13	B	4312.00	4368.17	56.17	10.17	0.181	0.88	1348.127	0.087	0.296	132.614
HEBRON_I-13	All Sands	3742.52	4368.17	399.53	44.39	0.111	4.66	2587.77	0.105	0.689	58.303
HEBRON_M-04	H	3881.69	3933.17	51.48	39.16	0.761	5.307	2806.309	0.136	0.53	71.669
HEBRON_M-04	G	3969.37	3980.62	11.25	1.65	0.146	0.196	29.993	0.119	0.192	18.199
HEBRON_M-04	F	4021.98	4034.12	12.14	1.45	0.119	0.111	3.89	0.076	1	2.692
HEBRON_M-04	E	4084.04	4138.12	54.08	3.78	0.07	0.289	9.567	0.076	1	2.532
HEBRON_M-04	D	4145.72	4163.85	18.13	7.51	0.414	0.861	6009.978	0.115	0.172	800.789
HEBRON_M-04	C	4173.10	4261.07	87.97	24.15	0.275	2.672	1157.907	0.111	1	47.948
HEBRON_M-04	BC Stringers	4314.12	4403.95	89.83	5.05	0.056	0.478	75.493	0.095	1	14.952
HEBRON_M-04	B	4476.15	4510.21	34.07	9.21	0.27	0.713	1902.903	0.077	0.654	206.594
HEBRON_M-04	All Sands	3881.69	4510.21	358.94	91.94	0.256	10.627	11996.041	0.116	0.66	130.473
L-93 22	H	3828.93	3854.36	25.43	13.97	0.55	2.026	741.756	0.145	0.211	53.082
L-93 22	G	3906.24	3923.30	17.06	6.19	0.363	0.839	661.625	0.136	0.163	106.924
L-93 22	F	3974.50	3987.85	13.35	6.89	0.516	0.671	74.528	0.097	0.694	10.812
L-93 22	E	4047.25	4111.71	64.46	20.93	0.325	3.126	4109.228	0.149	0.145	196.297
L-93 22	D	4134.36	4153.76	19.39	2.70	0.139	0.126	3.407	0.047	1	1.264
L-93 22	C	4173.76	4245.31	71.55	11.46	0.16	1.364	1593.381	0.119	0.801	138.989
L-93 22	BC Stringers	4282.33	4372.04	89.71	27.82	0.31	2.863	801.146	0.103	0.667	28.794
L-93 22	B	4445.64	4478.92	33.27	12.12	0.364	1.367	9630.005	0.113	0.253	794.798
L-93 22	All Sands	3828.93	4478.92	334.23	102.09	0.305	12.382	17615.078	0.121	0.401	172.547
L-93 29	H	3653.15	3698.83	45.68	6.41	0.14	0.933	631.447	0.145	0.615	98.492
L-93 29	G	3710.26	3724.74	14.48	6.11	0.422	0.952	1614.395	0.156	0.175	264.231
L-93 29	F	3772.51	3826.43	53.92	7.45	0.138	0.942	1076.611	0.126	0.263	144.434
L-93 29	E	3852.17	3865.39	13.22	0.00	0	0	0	0	0	0
L-93 29	D	3893.78	3911.36	17.58	8.04	0.457	0.564	226.88	0.07	0.637	28.215
L-93 29	C	3933.78	4020.57	86.79	61.57	0.709	8.499	19121.868	0.138	0.149	310.572
L-93 29	BC Stringers	4074.29	4203.08	128.78	17.99	0.14	1.531	100.367	0.085	0.673	5.579
L-93 29	B	4218.82	4253.30	34.48	6.69	0.194	0.721	4403.101	0.108	0.195	658.165
L-93 29	All Sands	3653.15	4253.30	394.93	114.27	0.289	14.141	27174.669	0.124	0.268	237.82

3 Reservoir Engineering

Reservoir engineering data and the resulting analysis and / or interpretations used as the basis for depletion planning are presented in this section. The data were derived from a variety of sources, including the exploration and development wells drilled in the area.

3.1 Reservoir Pressures and Free Water Levels

Pressure data gathered from wireline and DST operations are plotted in Figure 3-1. High-level observations from the plot show that the Hebron field 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 Jeanne d'Arc reservoirs in the M-04 and I-13 wells. Over-pressuring becomes more evident in the West Ben Nevis field (minor in the Ben Nevis Formation and more significant in the Jeanne d'Arc Formation) and in the Hibernia Formation of the Ben Nevis field.

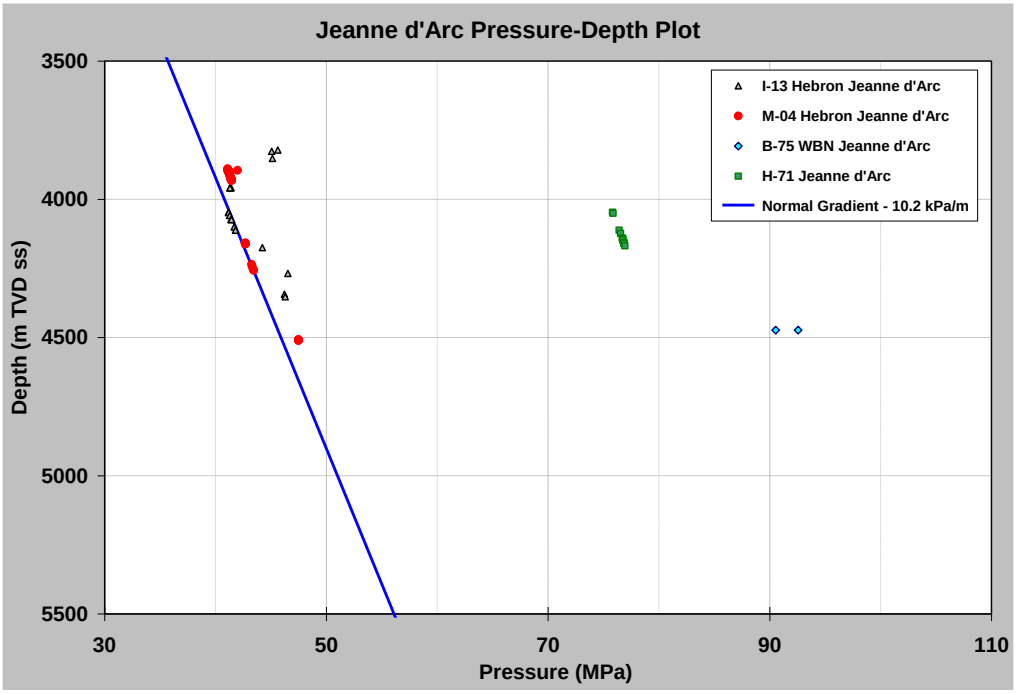


Figure 3-1 Hebron Asset Area Jeanne d'Arc Pressure Depth Plot

Pressure measurements recorded for the Jeanne d'Arc Formation in the Hebron field are plotted against depth in Figure 3-2. 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 Jeanne d'Arc Formation is normally to slightly over-pressured in the Hebron field. Consistent with observations in other pools, there is 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.

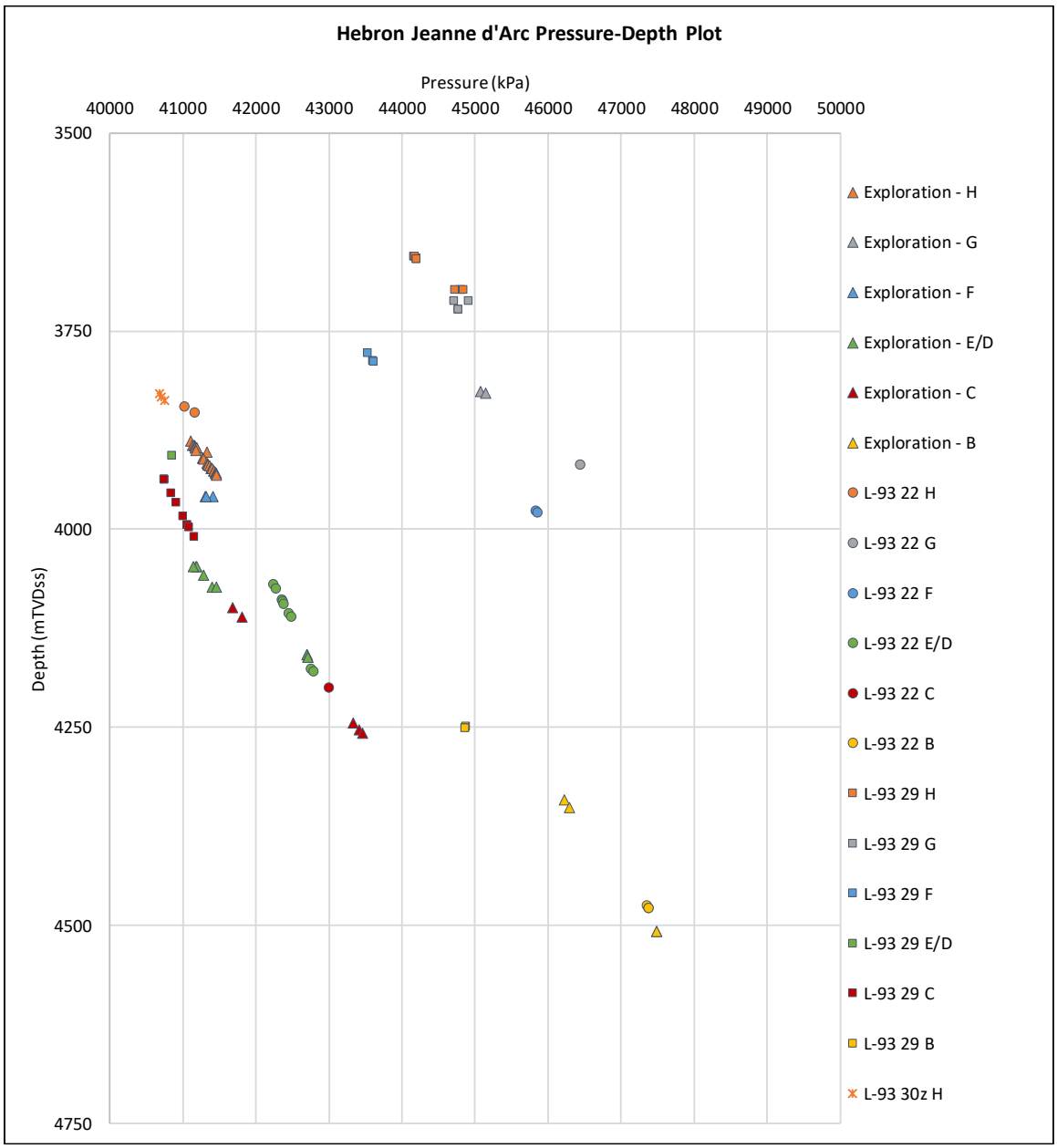


Figure 3-2 Hebron Jeanne d'Arc Formation Pressure Depth Plot

The log, core, fluid, and pressure data acquired for each sand were used to determine a most likely free water level for each sand. There has been evidence of perched waters and the extent of these contacts throughout the reservoir remains an uncertainty. The base case assumptions for initial pressure, pressure gradients, and free water level are listed in Table 3-1. A comparison of the initial pressure line to the data gathered to date is shown by sand in Figure 3-3 and additional detail is included in the subsequent sub-sections.

Table 3-1 Jeanne d'Arc Formation Initial Pressure and Free Water Levels by Sand

	Pinit kPa	@ Depth mTVDss	Oil Grad kPa/m	Water Grad kPa/m	FWL 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

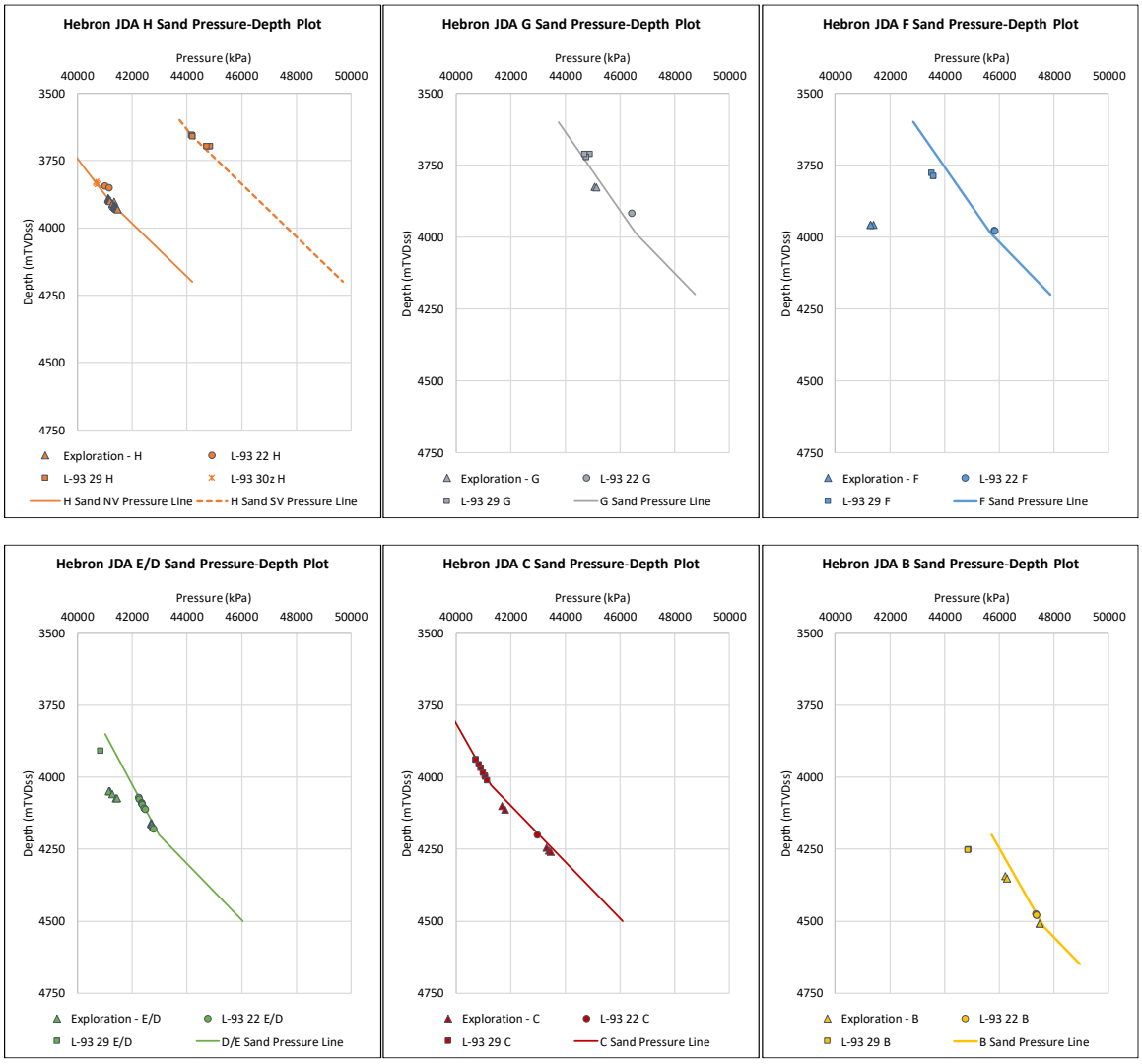


Figure 3-3 Hebron Jeanne d'Arc Pressure Depth Plot by Sand

3.1.1.1 H Sand Pressure and FWL

The H Sand data acquired in L-93 22 and M-04 are from North Valley (Figure 2-7). The water is pressured up relative to hydrostatic and the -3912m TVDss 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 -3657.5m TVDss. The pressure data acquired in the oil leg was elevated with respect to projections from North Valley and indicate the North and South valleys of the H Sand are not connected and form separate oil

accumulations. A free water level of -3660 mTVDss is based on the observed water saturation and the saturation height function.

3.1.1.2 G Sand Pressure and FWL

Pressure data for the G Sand were acquired in L-93 29 and L-93 22 as well as RFT pressure data in 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 the possibility exists that the G Sand is comprised of 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 ODT is -3978m TVDss. A free water level of -3986mTVDss, consistent with F sand, was assumed based on the similarity of the ODT data.

3.1.1.3 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 in data from L-93 29. Of the 3 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 be indicative of the limited lateral extent of individual sand bodies within the F Sand and potential for connectivity issues. F Sand oil down to (ODT) is -3980m TVDss from L-93 22 as F Sand was not developed in M-04. A free water level of -3986 mTVDss is based on the observed water saturation and the saturation height function.

3.1.1.4 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 sands is -4200m TVDss based on the intersection of the oil pressure line with the hydrostatic water line. The E and D sand are vertically close together and the E Sand is interpreted to cut into the D Sand.

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. E Sand was not well developed in L-93 29 and no additional pressure data were collected.

3.1.1.5 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 -4028m TVDss.

3.1.1.6 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 free water level is -4520m TVDss 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 was used as a history matching parameter for the simulation model. It should be noted that the test was considered to be medium quality but appears to be valid.

3.2 Reservoir Temperature

Reservoir temperature information was gathered during the drilling and production testing operations of the Hebron area wells. 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, the L-93 22, the first Jeanne d'Arc Formation development well, included temperature gauges within four of the sands through use of intelligent well completion technology. There is good alignment between both datasets. Reservoir temperatures for the Jeanne d'Arc Formation are plotted in Figure 3-4. The best fit regression of the data indicates a temperature gradient of 2.6°C/100 m.

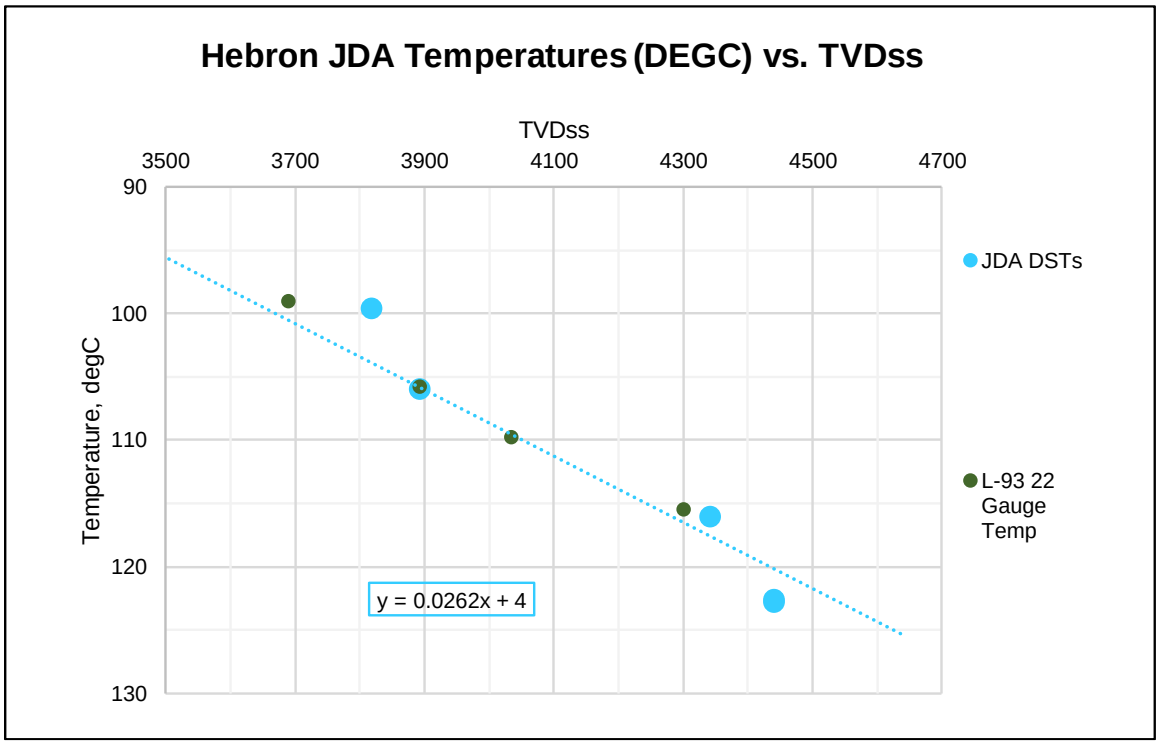


Figure 3-4 Jeanne d'Arc Formation Temperatures Depth Plot

3.3 Fluid Properties

Multiple bottom hole and separator-fluid samples were acquired from several productive intervals of the wells drilled across the Jeanne d'Arc reservoir. There is a higher degree of uncertainty with the results from the exploration wells, particularly those which were based on surface samples due to the 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 3-2 provides a high-level summary of the fluids 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 3-2 Summary of Jeanne d'Arc Formation Oil Fluid Properties by Well and Sand

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 either L-93 22 or L-93 29 are included. These fluid samples are deemed to be of highest confidence, and they provide a good representation of the changes in fluid properties across the Jeanne d'Arc sands.

Table 3-3 Summary of Jeanne d'Arc Formation Compositional Data

Sand	**F**	**E**	**C**	**B**	**B**
Well	L-93 29	L-93 22	L-93 29	L-93 29	L-93 22
Sample type	BH (Uncont-aminated)	Surf. Recombined	BH (Uncont-aminated)	BH (Uncont-aminated)	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

Individual fluid models are populated in the simulation model based on the observed data. The H Sand continues to be based on the M-04 data as the samples acquired from the L-93 22 could not be recombined as the rates were too low to accurately measure the gas-oil ratio. Samples have been acquired from the L-93 30z but the results have not been received. There is no new sample available for

the G sand, but the limited data from the I-13 DST aligns well with the F Sand results from the L-93 29. High quality analysis is available for each of the D/E, C, and B in order to generate the simulation tables. A comparison of the simulation fluid tables to the available fluid properties results for each of the sands is shown in Figure 3-5 and Figure 3-6. In general, the fluid properties were well represented across the sands. There was slightly different behaviour in the lighter D/E sand interval. The match of the equation of state has some room for improvement but the minor discrepancy will not have a material impact on the prediction for the sand.

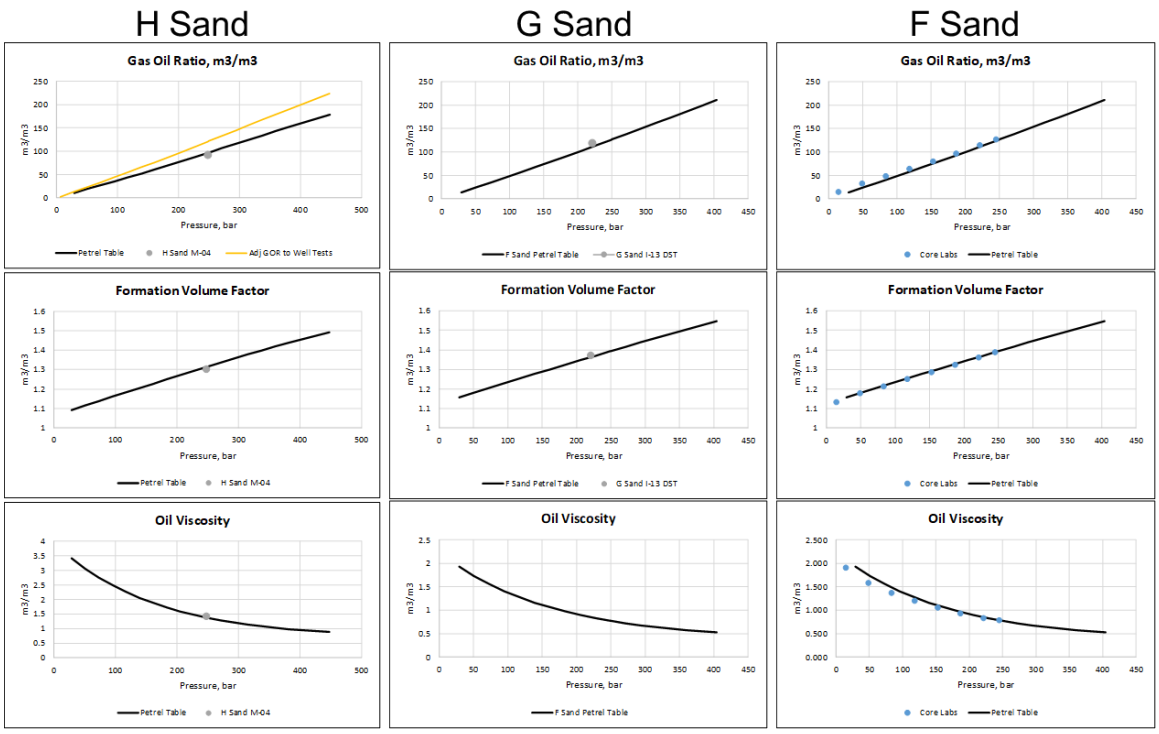


Figure 3-5 Simulation PVT Table vs. Lab Results for H, G, and F Sand

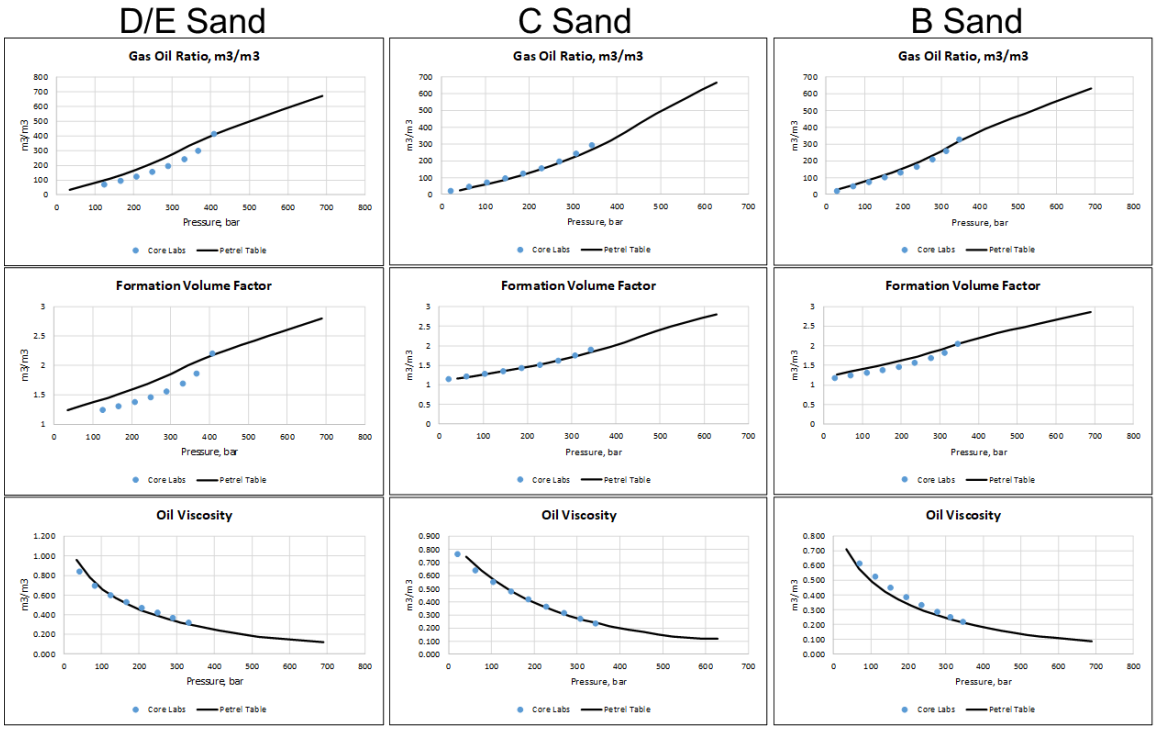


Figure 3-6 Simulation PVT Table vs. Lab Results for D/E, C, and B Sand

No formation water samples were acquired from the Jeanne d'Arc Formation in the exploration wells. A downhole water sample was acquired from the L-93 29 in the H Sand South Valley. In addition, a produced water sample was acquired from the 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 Jeanne d'Arc Formation. The samples are shown in Table 3-4 as compared to the regional water data acquired from the Ben Nevis (Pool 1) and Hibernia (Pool 5) formations.

Table 3-4 Summary of Hebron Area Water Properties

	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

3.3.1 Flow Assurance Considerations

This section deals with the potential flow assurance issues that may occur from the reservoir to the wellhead.

3.3.1.1 Hydrates

Ambient temperature conditions in the Hebron area are sufficiently cold that hydrates could form. The minimum sea water temperature (MSWT) is −1.7 °C. During normal operations, the wellbores will be sufficiently warm such that they are not in the hydrate formation region. During transient operation, hydrate inhibitors may be used to prevent hydrate formation. If a hydrate blockage develops, chemicals can be applied to melt the hydrates.

3.3.1.2 Wax Management

The wax appearance temperatures (WAT) for the Jeanne d'Arc sands were measured using the Cross Polarized Microscopy (CPM) technique from samples acquired in the M-04 exploration well. Wax deposition in the wellbores of the platform wells is not expected during normal operations. The WAT for the Jeanne d'Arc sands is between 41°C and 51°C.

3.3.1.3 Asphaltenes

Laboratory analysis performed on fluid samples from the Hebron Jeanne d'Arc sands indicate that asphaltene precipitation is not expected in most of the wells. There is the potential for some asphaltene precipitation in the wells completed in the Jeanne d'Arc Formation and so these wells may require downhole injection of asphaltene inhibitor at the completions.

3.3.1.4 Scale Management

The potential exists for calcium carbonate scale precipitation and deposition. To control this, scale inhibition will be provided for the wells. Acid washes may be used as a secondary form of mitigation for calcium carbonate scales.

3.3.1.5 Corrosion Management

The potential for corrosion exists throughout the entire production system as CO2 and water will be present in the produced fluids. Corrosion-resistant alloy production tubing and flowlines will be selected to mitigate expected corrosion or downhole / wellhead corrosion inhibitor injection will be used in combination with carbon steel. Hydrogen sulphide was not initially present in the reservoir, but field experience shows that injection of seawater (and hence sulphate ions) into the reservoir can result in generation of H2S from sulphate-reducing bacteria (SRB) activity. While the timing and extent of souring in the Jeanne d'Arc is uncertain, it is expected that the gas lift gas will have elevated H2S content as a result of Pool 1. All production wells are designed to mitigate near term expected H2S levels, with plans to update metallurgy as required.

3.4 Special Core Analysis

Early SCAL data for the Jeanne d'Arc Formation from the I-13 exploration well has reliability issues and was not used in this assessment. A special core analysis study is currently underway for the Pool 4 H Sand using core acquired from the L-93 22. Core plug cleaning and restoration has been completed and the lab is proceeding with the experiments. Select early results have been received and will be referenced in subsequent sections as available. The full program will include

- Composite Program: Steady state water-oil imbibition and drainage relative permeability. No gas-oil relative permeability will be assessed given the lack of compression pressure to reach the deeper reservoirs.
- Centrifuge Relative Permeability Program: Measure values at low levels of oil saturation beyond what can be measured in steady state method; measurements across different facies.
- Centrifuge Primary Drainage Capillary Pressure: Air-Brine primary drainage capillary pressure to inform initial water saturation and saturation height function.

Preliminary results from the SCAL program were used to calibrate the correction for perm to oil to be used in the simulation model. As shown in Figure 3-7, the best fit correlation through the available dataset results in a reduction in permeability by a factor of 0.87x.

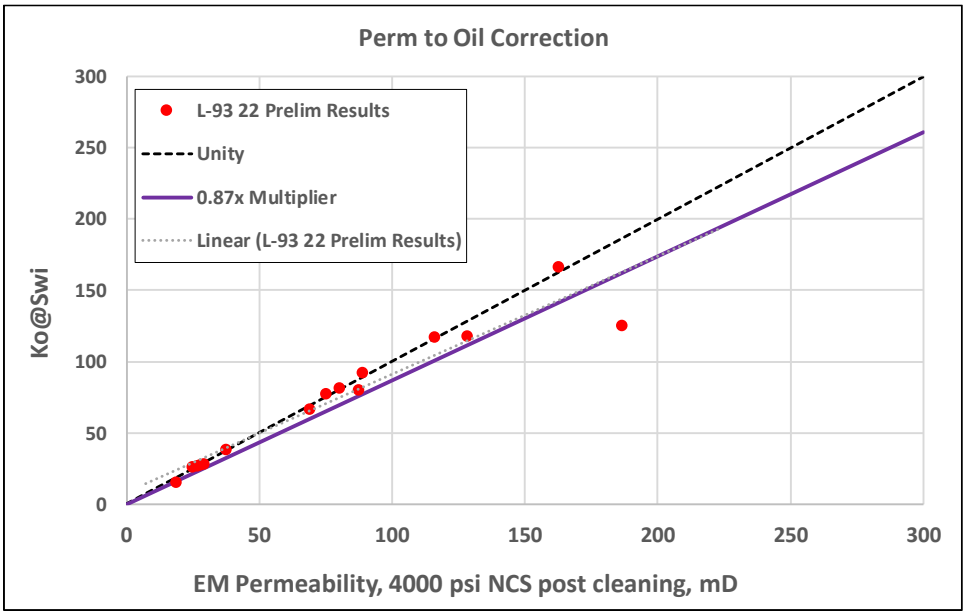


Figure 3-7 Jeanne d'Arc Correction for Perm to Oil

3.4.1 Saturation Height Functions (WO Primary Drainage Capillary Pressure)

The original saturation height functions used for the Jeanne d'Arc Formation were sand specific (H and B Sand) and based on matching to log (Archie) water saturation. In 2021 the H Sand function was updated to incorporate the results from the L-93 22. In 2022, the saturation height function for the B Sand was revisited to incorporate the results from the L-93 22 and the L-93 29. Emphasis was placed on matching to the newer vintage logs. The best fit height function, as described in Figure 3-8, was compared in all of the Jeanne d'Arc sands and found to provide a reasonable match in all of the sands. The sand by sand comparison is shown in Figure 3-9.

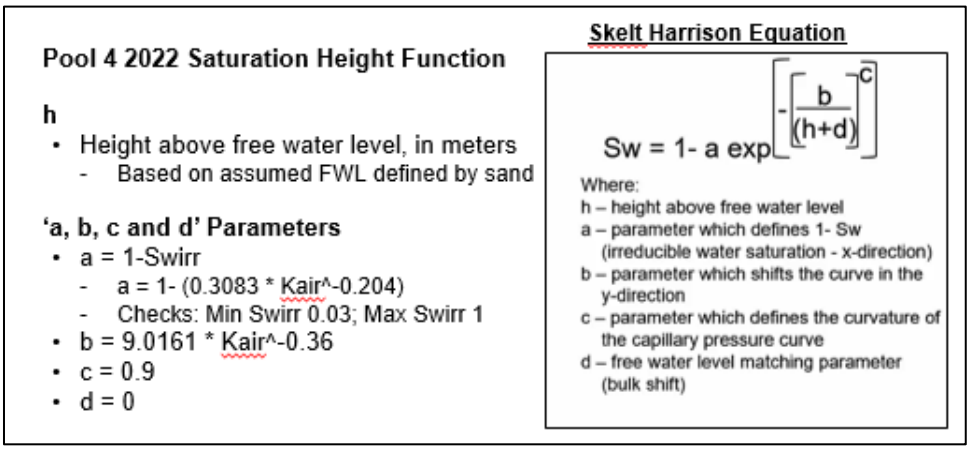


Figure 3-8 Jeanne d'Arc Formation Unified Saturation Height Function

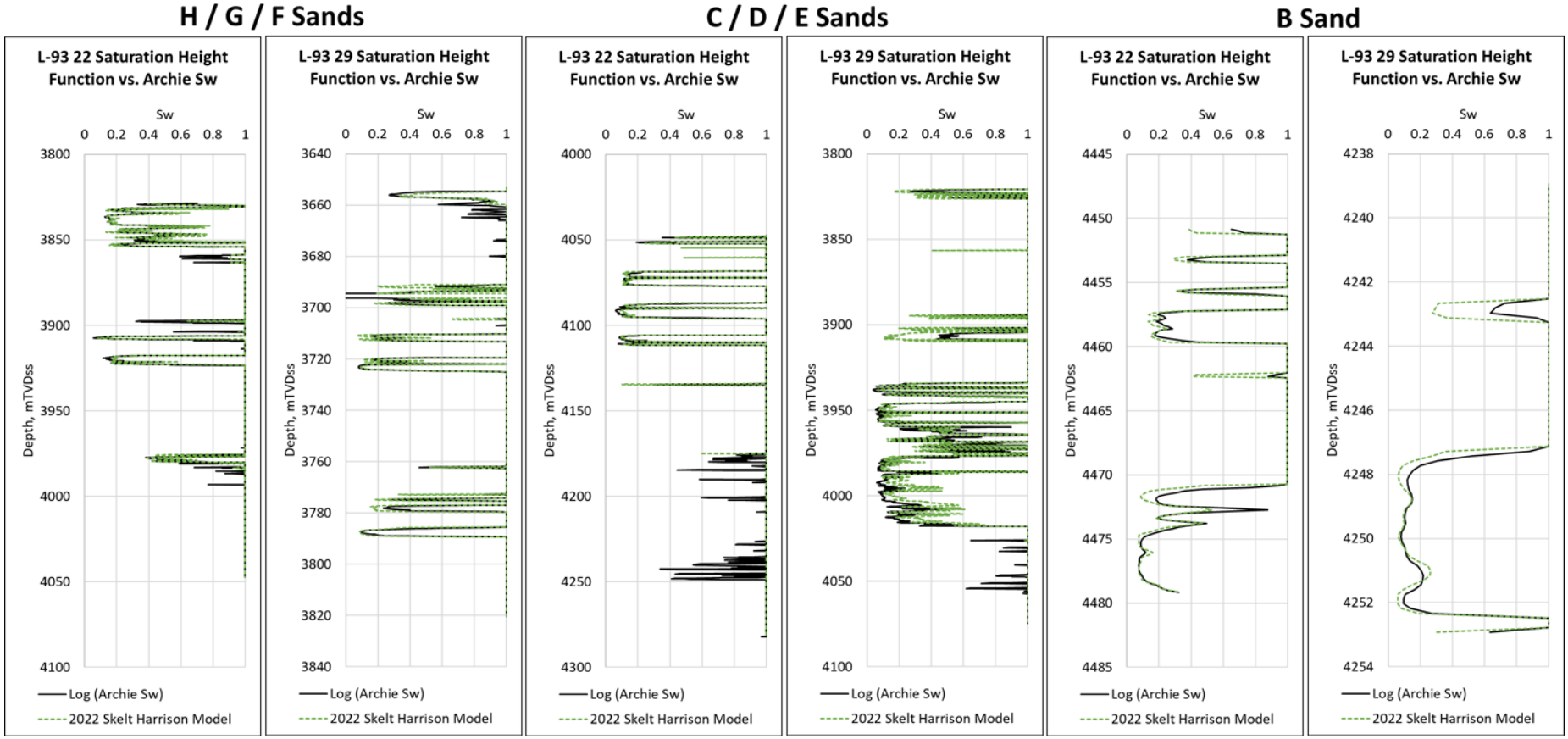


Figure 3-9 Comparison of Unified Saturation height Function to Archie Water Saturation

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 enabled a blind test of the unified saturation height function. 8 core plugs were tested and the resultant capillary pressure is compared to the predicted values based on the saturation height function in Figure 3-10. The comparison showed reasonable alignment. The saturation height model will continue to be refined as needed.

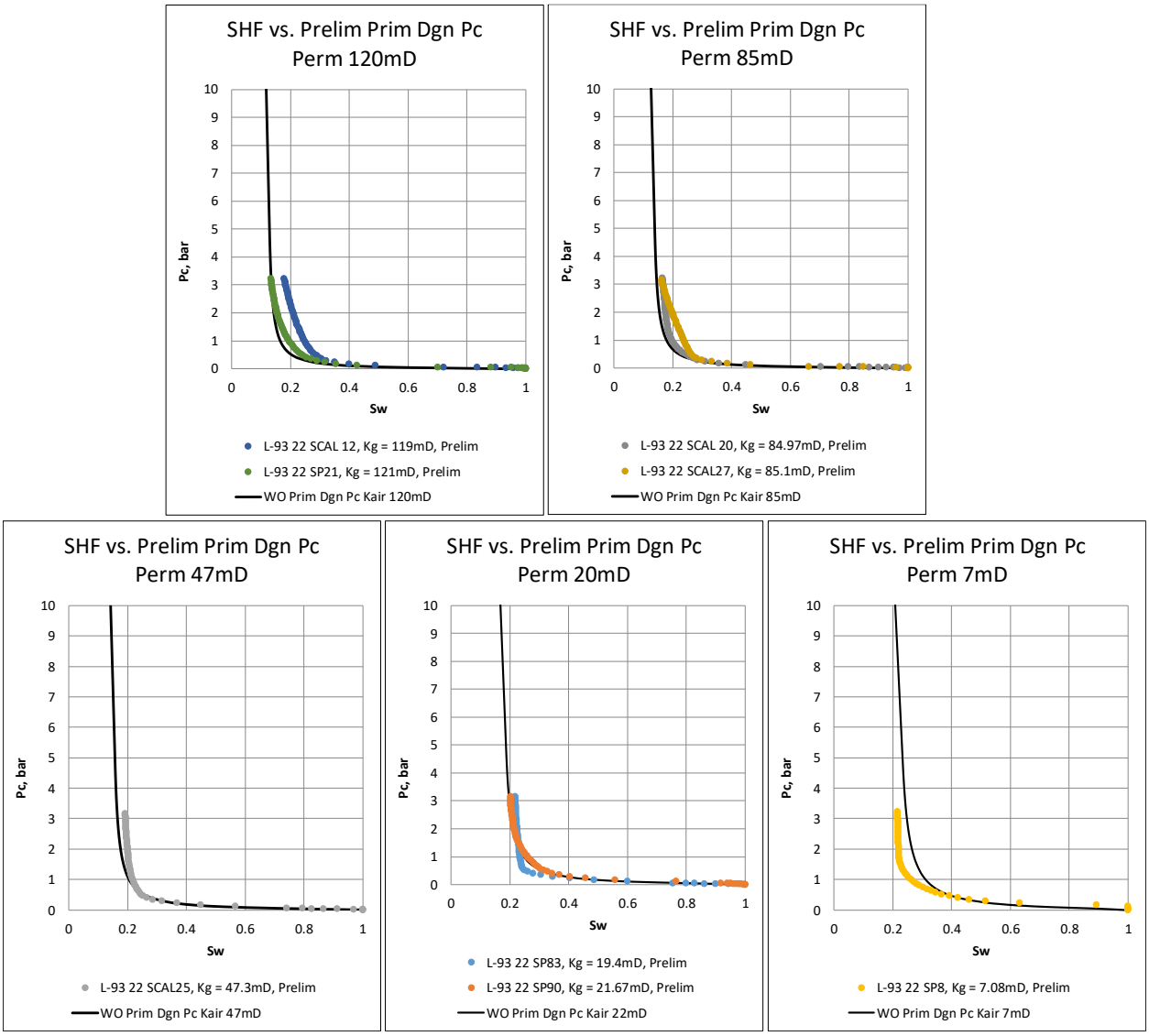


Figure 3-10 Comparison of Unified Saturation Height Function to Preliminary L-93 22 H Sand Primary Drainage Capillary Pressure

The 2022 Jeanne d'Arc Formation simulation model is set up with capillary pressure tables generated from the unified saturation height function, as shown in Figure 3-11. 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.

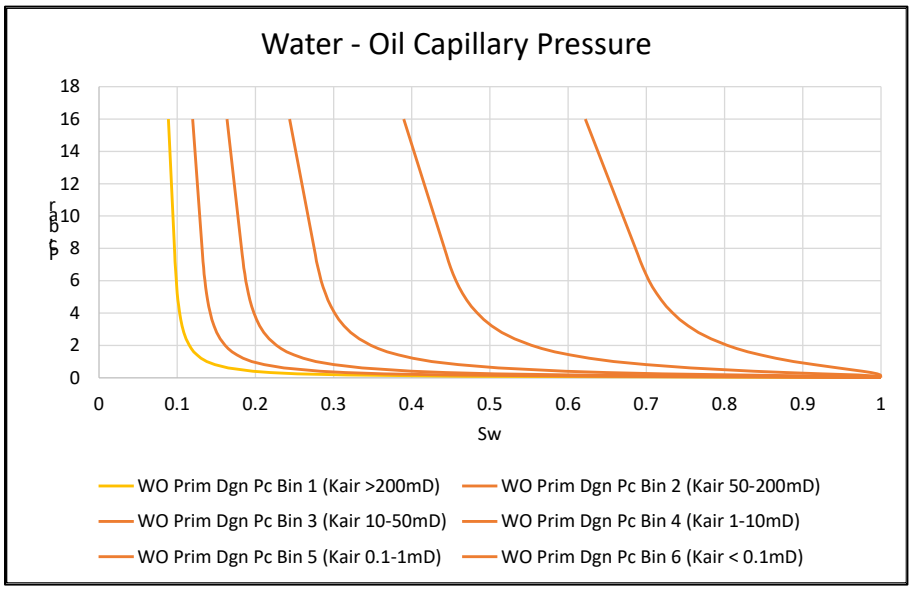


Figure 3-11 Jeanne d'Arc Formation Water-Oil Primary Drainage Capillary Pressure Curves

3.4.2 Relative Permeability

Corey type-equations were used to define the relative permeability inputs for the Jeanne d'Arc 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. The Corey exponents currently in use are compared to the L-93 22 composite 1 results in Figure 3-12. There is reasonable alignment, and the results are consistent with analogue data for intermediate-wettability displacement behaviour. As the remainder of the SCAL results are received for the 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.

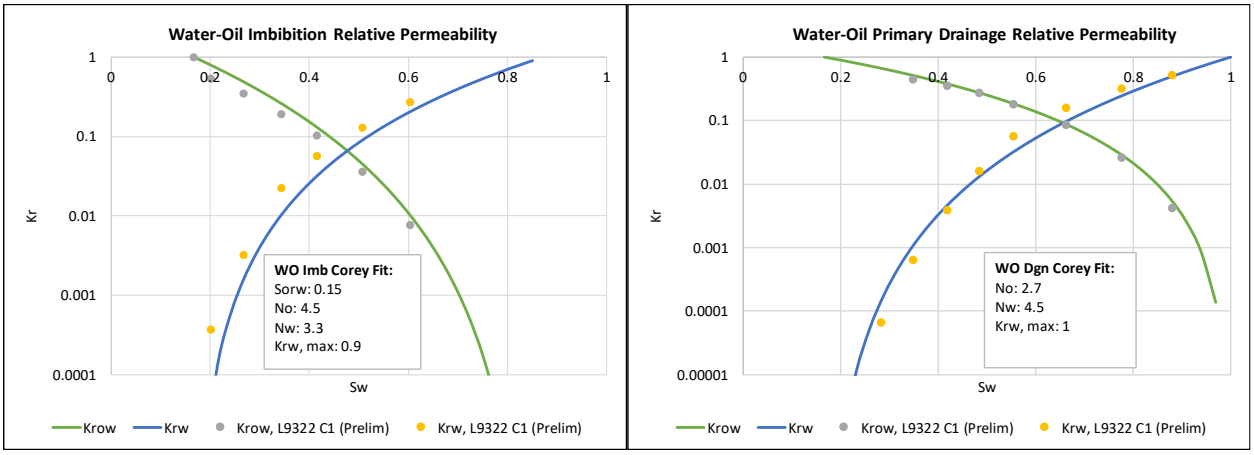


Figure 3-12 Pool 4 Water Oil Relative Permeability

3.5 Drill Stem Test Results

The M-04 and I-13 wells were drilled into the Jeanne d'Arc Formation in the Hebron field. Drill stem tests were conducted within the B and G sands in the I-13 and in the H Sand in the 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
- Poor accuracy in the flow data especially for low flow rate situations.

The summary of the results from the DST analysis are shown in Table 3-5.

Table 3-5 Summary of Hebron Jeanne D'Arc DST Tests

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

3.6 Production Results

The first Pool 4 development well was brought online in 2021. The L-93 22 was drilled with the primary objective of the H Sand. Secondary objectives were identified in the deeper sands. The well was drilled through to the base of the Jeanne d'Arc Formation and completed with an intelligent well completion (IWC) for an extended flow test on additional sands. Four separate zones were completed in the H, G, E, and B sands – each with surface controlled ICVs with dedicated pressure and temperature gauges. The G and the E sands are not included in the Hebron Development Plan and their production was approved for a period of 12 months through the Hebron Project Pool 4 Extended Formation Flow Test. A summary of the production by zone is shown in Figure 3-13.

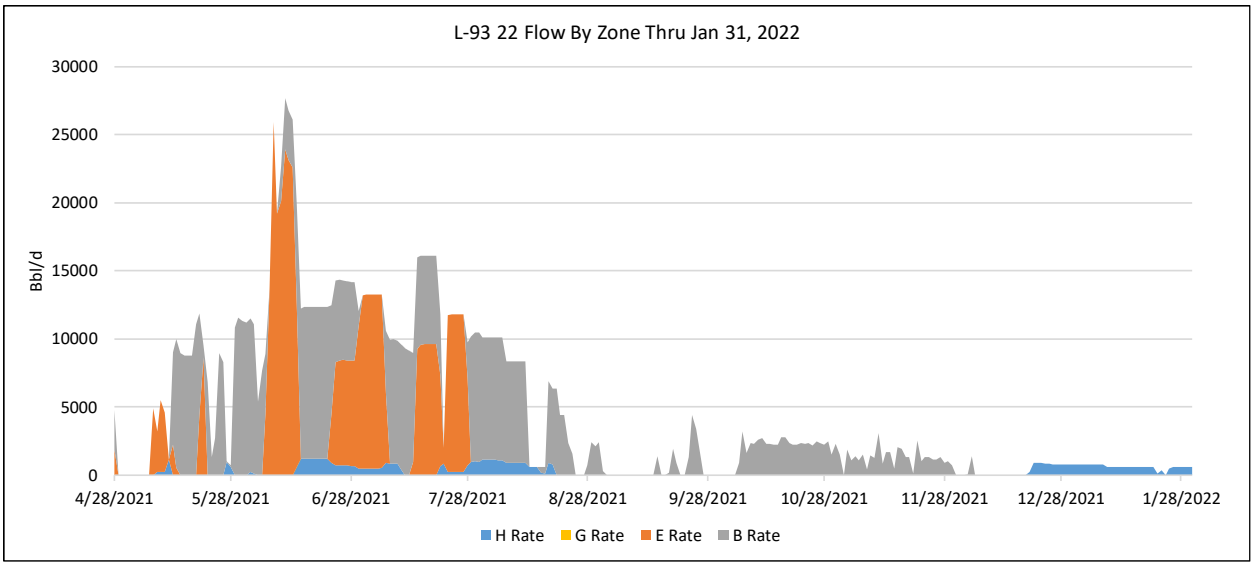


Figure 3-13 L-93 22 Extended Flow Test Production by Zone

The second development well, the L-93 30z, was drilled in the second half of 2022. The L-93 30z is a horizontal producer targeting the H sand. There is insufficient dynamic data at the time of this report to make any conclusions with regard to dynamic performance.

A brief summary of each of the sands is provided in the subsequent subsections.

3.6.1 H Sand Performance

The H Sand L-93 22 dynamic performance indicated lower productivity than pre-drill expectations with a PI of 0.007 m3/d/kPa and initial rate of ~1kbd. 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 indicated two boundaries in close proximity to the well. The material balance analysis indicated a very low connected volume, consistent with the pressure transient analysis (PTA) observations.

The L-93 22 well was drilled near the edge of the valley axis. The current interpretation is that the location of the well is one of the key drivers for the poor performance. In addition, it highlighted the importance for future producers being horizontal in order to increase the chance of connectivity. The learnings from the L-93 22 were incorporated into the design of the first horizontal producer. The L-93 30z was drilled in the second half of 2022. There is insufficient dynamic data at the time of this report to make any conclusions with regard to performance.

3.6.2 G Sand Performance

There should have been sufficient productivity for the G Sand interval to flow. High drawdown was applied in an attempt to flow the well but no production could be achieved. To date there has been no flow from the G sand. It is unknown at this time if the cause is due to a reservoir issue or a mechanical issue. An attempt was made to inject into the interval to determine if that would help clean up the perforations, but there was no injectivity into the zone. Potential future well work remediation options will continue to be investigated.

3.6.3 E/D Sand Performance

A high quality E Sand interval was observed in the 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 ~4200mTVDss. The E Sand productivity was very high with a PI of ~0.7 m/3/kPa and peak rate of 28 kbd. There was good alignment with observations from simulation modeling and analytical models (PTA & MBAL). All models consistently showed a volume of well-connected oil of ~26 MB with a total E/D OIP of ~40 MB. 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 that time and the pressure is slowly building.

3.6.4 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 m3/d/kPa and a peak rate of 12 kbd. The measured fluid properties aligned well with the exploration dataset. A key observation from the pressure transient analysis was that the best fit permeability thickness of 600mD-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 utilized in late 2021 to shift the B-sand ICV to the closed position. ICV functionality remained for the H, G, and E sand. 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 brought back online. With the B 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.

3.7 Reservoir Model

3.7.1 Geologic Model

A geologic model was constructed for Pool 4, encompassing all reservoir sands (B through H, except for the H Sand North Valley). The framework is a pillar grid that includes all major faults in the model area, and some of the minor faults, totaling 29 modelled faults. There are some minor faults that were excluded for simplicity in this multi-sand model. These excluded faults will be considered on a sand-by-sand basis when required for detailed well design. Gridding of the pillar grid is 100m x 100m. The cells take a “zig-zag” pattern around faults to reduce cell distortion, making this grid suitable for simulation.

Horizons were generally modelled using seismic interpretation. For some surfaces that were more difficult to map (Base G, Base E, Top and Base D), the horizon was modelled using a thickness map from a higher confidence seismic surface. All surfaces were flexed to match well tops (the amount of flex required at each well was shown in Table 2-1).

The model is layered using proportional layers, targeting ~1m layer thickness in each of the reservoir intervals. The non-net shale zones that separate the reservoir sands are modelled as a single layer each, regardless of thickness. The total cell count in the model is 6.8 million cells.

Each sand has an environment of deposition (EOD) interpretation that is loaded into the model. The exception is the D sand, which is mapped over a relatively limited area, which represents the interpreted extent of the fluvial system; therefore, no additional EOD overprint is needed. The EOD property is used to organize properties by putting different reservoir quality distribution for each EOD. The EODs element descriptions vary by sand as described in Section 2.1.2.1 but for modelling purposes these were simplified to equate to amalgamated fluvial (highest net/gross or reservoir quality); non-amalgamated fluvial (moderate net/gross or reservoir quality); and coastal plain (generally non-net). In essence the maps are describing the probability of finding better net/gross and reservoir quality in a given area and will vary by sand. EOD maps are interpreted from integration of several data types, including well data, thickness trends, seismic amplitudes, and geologic concept.

Key properties in the geologic model include porosity and permeability. Porosity is modelled from the well logs, by EOD. Porosity distribution is determined for each sand and EOD based on the wells within that sand / EOD combination, with adjustments to the distribution applied as required to honour the geologic concept. There are no facies or net/gross properties modelled prior to the porosity modelling step. Permeability is calculated from porosity, using a porosity-permeability transform. The geomodel-scale porosity-permeability transform is a scaled-up version of the core plug scale transform described in Section 2.3.2.7. This grid and porosity / permeability properties are used directly in the simulation model; no upscaling is performed in the transition from geomodel to simulation model. Water saturation is modelled at the simulation step, using the relationships described in Section 3.4.1.

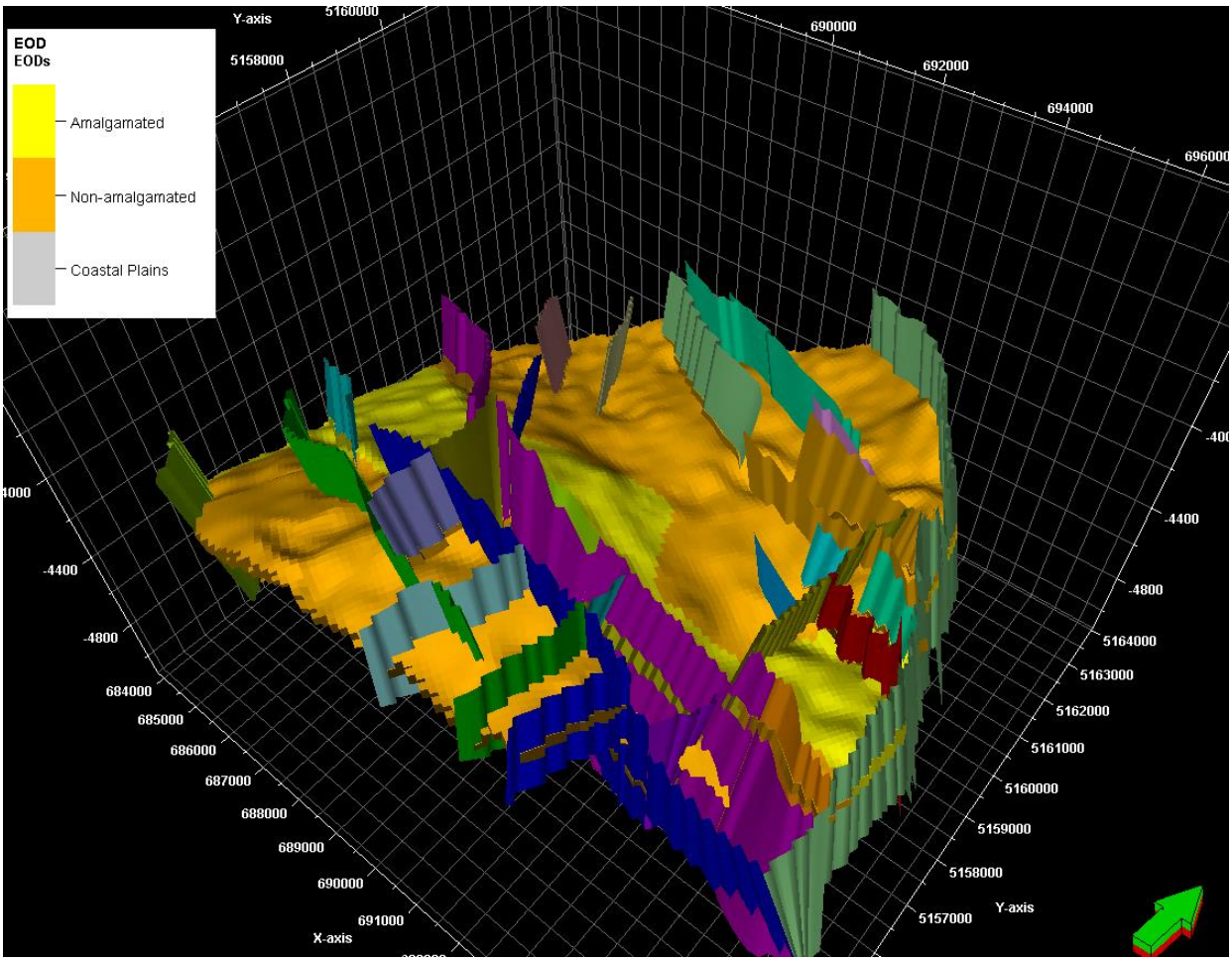


Figure 3-14 3D view of C Sand portion of geomodel, showing the EOD property and all modelled faults

3.7.1.1 H Sand North Valley Model

While the H Sand surfaces were included in the 2022 JDA model, the H Sand model remains consistent with the documentation in the 2021 Annual Production Report. A new development well, the L-93 30z, was drilled in 2022 but early production learnings from this well are still being incorporated. For the purposes of the development plan amendment, the best estimate 2021 model is being used as the basis for the H Sand development flowstreams.

The Best Estimate Model represents a scenario with moderate connectivity and NTG. 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 modeled 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.

3.7.2 Simulation Model and History Matching

The building of the underlying geologic model was an iterative process incorporating learnings from the dynamic data where available. In the sands which do not have any dynamic data, the methodology was based on another sand which was determined to be the best analogue. The C Sand does not have any dynamic data and was modeled with the same methodology as the B Sand.

3.7.2.1 H Sand History Match

The L-93 22 well performance indicated substantially lower productivity as compared to pre-drill expectations. This compares to strong dynamic performance from the original DST in the exploration M-04 well.

Details of the historical well dynamic performance were included in the 2021 Hebron Annual Production Report. Overall, the dynamic observations from both M-04 and L-93 22 could not constrain the range of model scenarios. Modeling work continues on the H Sand in order to incorporate the performance from the first horizontal producer (L-93 30z).

3.7.2.2 G Sand History Match

The I-13 DST 5 was run in the simulation model to assess the performance match. The model productivity was substantially lower than that observed in the DST test. The model was run with and without the observed skin value, in both cases the well was unable to achieve the rates observed in the DST. The model was built by upscaling the log based porosity and permeability at the wells. Given the limited length of the DST the well properties are the primary influence on the DST match. The log based permeability thickness for the G Sand is lower than the observed DST values (360 mD-m log value vs. 2040 mD-m DST value).

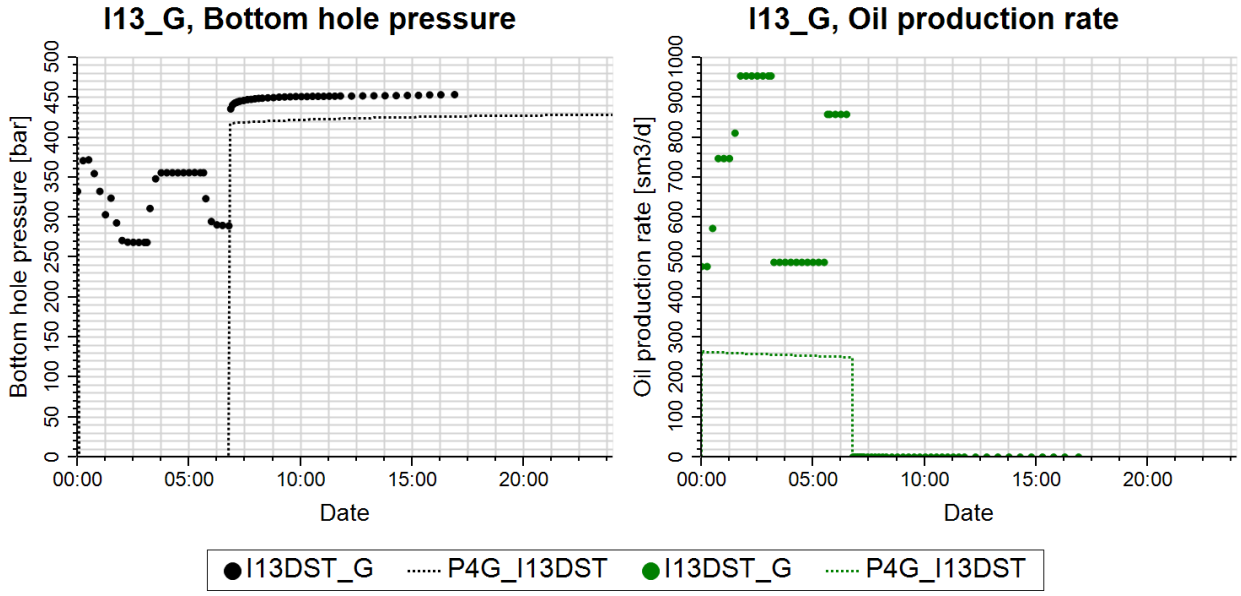


Figure 3-15 G Sand I-13 DST 5 Simulation Results

The L-93 22 G Sand production attempts did not achieve any oil production to surface. As observed in the pressure data, a large pressure drawdown was experienced across the reservoir. The model was run with the pressure data as the input to determine the model predicted oil production rates. The perforated interval has a permeability thickness of ~200mD-m. The model results indicate rates in the range of 100-250 m3/d should have been possible during the production periods.

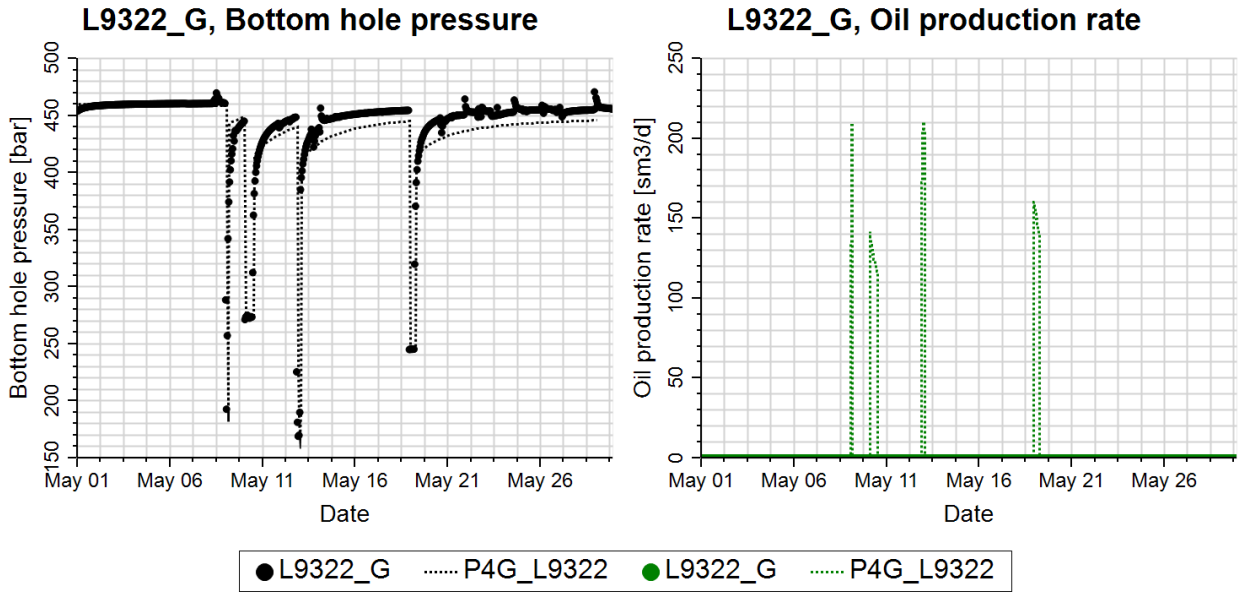


Figure 3-16 G Sand L-93 22 Simulation Results

The dynamic results observed in the two wells in the G Sand showed conflicting results. The I-13 DST indicated the model had insufficient productivity whereas the L-93 22 indicated the model had too much productivity. Both data sets have their own uncertainties with the vintage of the I-13 DST and the potential for mechanically driven issues in the L-93 22. Given the range of observations and the remaining uncertainties, no edits were made to the simulation model in order to improve the match to the dynamic data.

3.7.2.3 E/D Sand History Match

The L-93 22 production dataset from the E Sand interval is of high quality with sufficient production volume to be meaningful of reservoir performance. An iterative process was conducted with the geomodel in order to guide the property generation process for the E/D Sand in order to limit history matching updates. The pressure transient analysis from L-93 22 E Sand indicated a permeability thickness that was well aligned with the original log based assessment. The material balance and pressure transient data was used in conjunction with the seismic data to define the extent of the high quality EOD. The dynamic data indicates very good connectivity within the amalgamated, high quality EOD and limited additional connected volume. The best fit to the dynamic data was achieved with a moving average property generation methodology. The porosity and horizontal permeability were generated through the property generation process. The 2022 refinement of the E Sand porosity-permeability transform resulted in a reduced log based permeability. Given the good match to the dynamic data, the original permeability log was used as the basis for the average properties in the high quality EOD. The best fit match in simulation was achieved with a KvKh of 0.1 within the amalgamated EOD. The KvKh was set to 0.01 in the non-amalgamated consistent with the other sands. There were no additional history match edits required and the match to performance is shown in Figure 3-17.

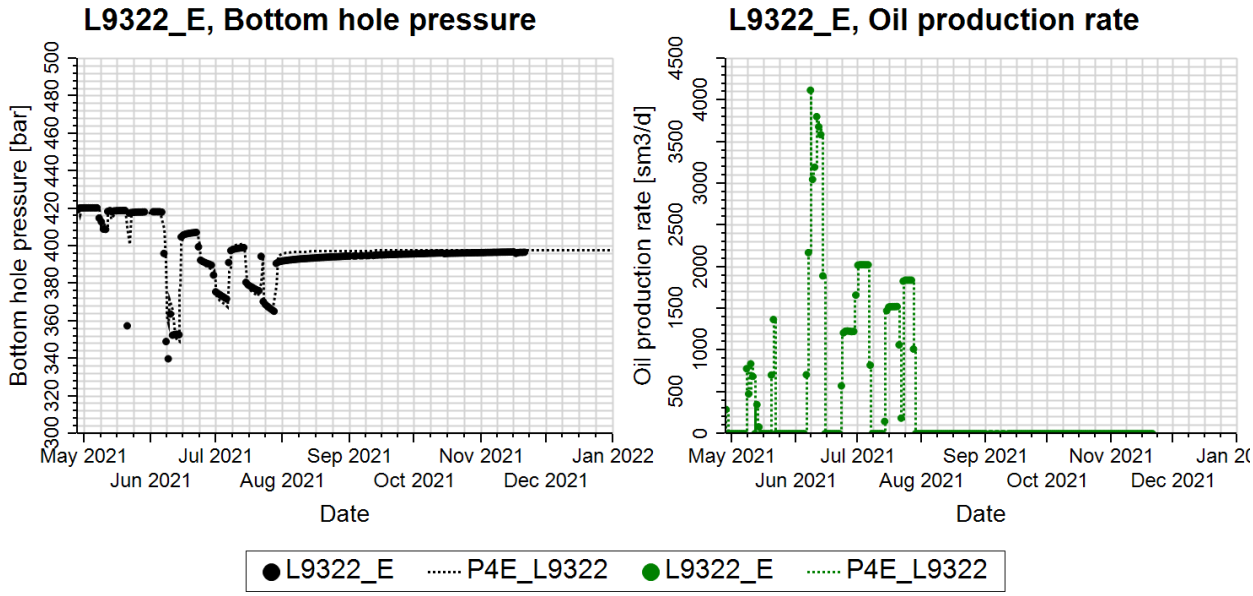


Figure 3-17 E Sand L-93 22 Performance Simulation Results

3.7.2.4 B Sand History Match

The L-93 22 production dataset from the B Sand interval is of high quality with sufficient production volume to be meaningful of reservoir performance. An iterative process was conducted with the geomodel in order to guide the property generation process for the B Sand in order to limit history matching updates. The pressure transient analysis from L-93 22 B Sand indicated a permeability thickness lower than the log based value by an order of magnitude. Given this difference, it was expected that heterogeneity in the model would be key to honoring the dynamic data. The best fit to the dynamic data was achieved with stochastic property generation with a limited variogram size of 100m. The porosity and horizontal permeability was generated through the property generation process. The best fit match in simulation was achieved with the following simulation assumptions and edits:

- KvKh ratio of 0.01
- Maximum cell permeability 1000mD
- Cells with <1mD perm made inactive
- Fault transmissibility multiplier 0.001

The match to the L-93 22 performance is shown in Figure 3-18. The key match parameters were the well drawdown and shut-in pressures. An increased pressure drop started to be observed across the ICV starting in August 2021. This additional pressure drop was not included within the model. In addition to the L-93 22 direct performance observations, a pressure was measured in an updip location from the L-93 29 (South Valley pilot hole). The pressure indicated a depleted pressure relative to the original B sand pressure line and was assumed to be due to production from L-93 22. The pressure depletion was used within the history match process and the final match is shown in Figure 3-19.

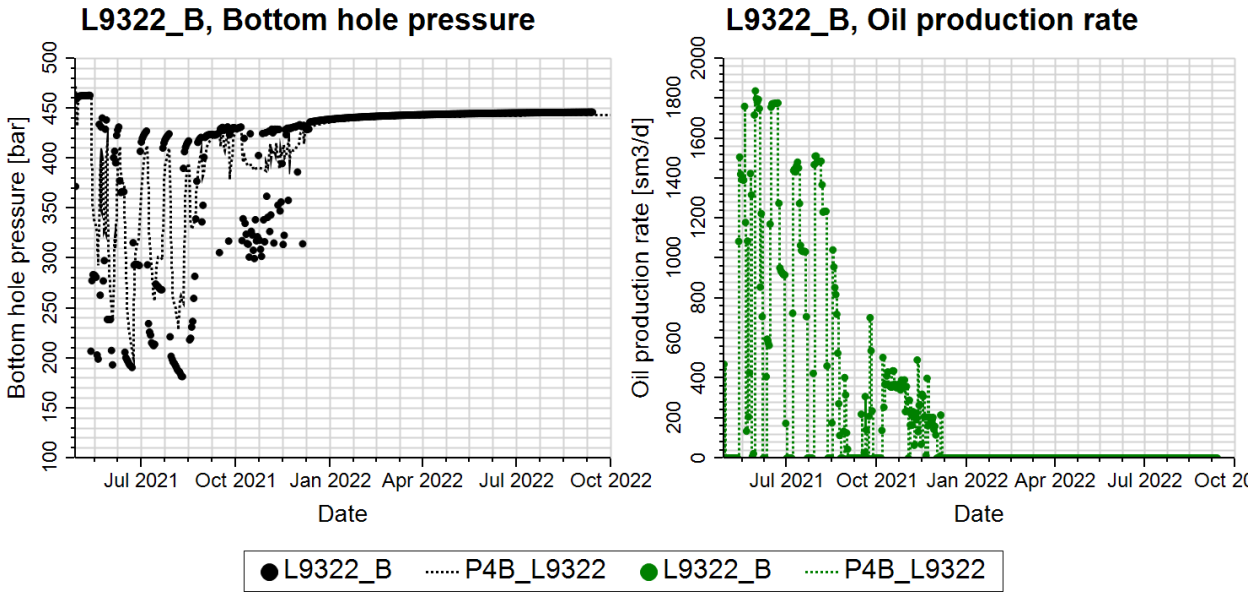


Figure 3-18 B Sand L-93 22 Performance Simulation Results

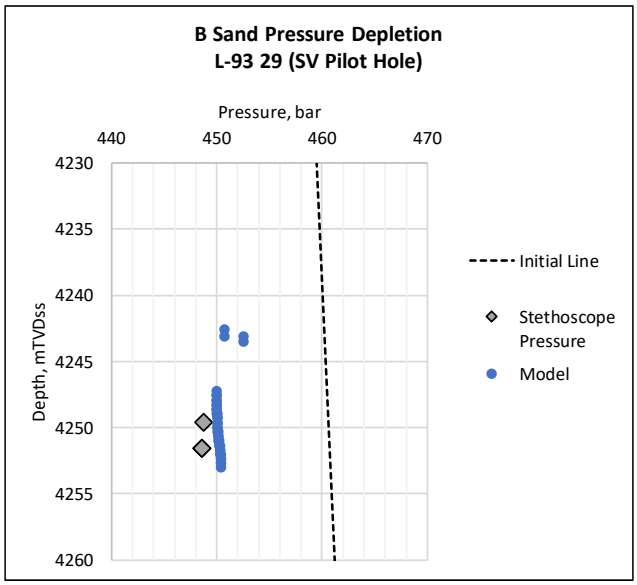


Figure 3-19 B Sand L-93 29 Pressure Depletion Simulation Results

The I-13 DST 5 was run in the simulation model to assess the performance match. The model was run incorporating the edits from the L-93 22 history matching process. As shown in Figure 3-20, there is a reasonable match to the DST results.

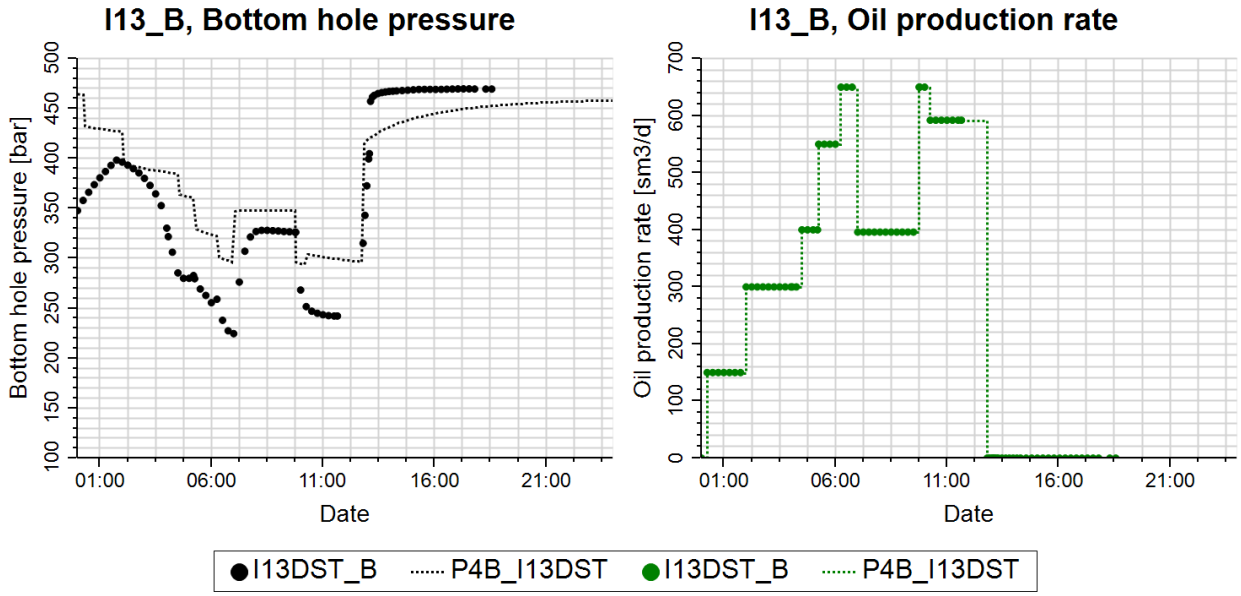


Figure 3-20 B Sand I-13 DST 1 Simulation Results

4 Reservoir Exploitation

The following section discusses the development of the Jeanne d'Arc Formation sands. Within the document, the hydrocarbon accumulations for the various sands will be referred to as Pool. For example, Pool 4H refers to the JDA H Sand.

4.1 Reservoir Exploitation Overview

The objective of the resource development planning process is to maximize the economic value of recoverable hydrocarbons in the Jeanne d 'Arc (JDA) Formation. In line with this objective, several reservoir exploitation schemes were evaluated with consideration given to areas with increased development opportunities, and reduced uncertainties and risks. This section includes the current basis for the exploitation of the in-place resources in the JDA Formation. The basis has leveraged learnings from the initial pilot/development wells in the JDA, specifically L-93 22 and L-93 29 wells. It is expected to evolve with learnings from additional drilling, production history and performance. Recognizing uncertainty with the connected fault blocks, the development is focused on the Horst Block and existing well control. Learnings from future JDA wells will be incorporated into updated resource descriptions and optimization of the depletion plan. This optimization may include wells targeting additional fault blocks where viable.

The depletion scenarios are based on a single deterministic realization of the potential development created from the current understanding of geological data and reservoir performance and constrained by the current drilling schedule forecast. The schedule assumes that the drilling program for all wells is executed by the existing platform rig. The planned well sequence is subject to change as a result of on-going depletion plan studies and the data gathered during the early phase of the drilling program.

The current basis assumes application of existing technologies, including existing well designs and gas lift but it also recognizes the potential to realize additional value through the adoption of new technologies to improve both recovery and operational efficiencies. As a result, the opportunity to include advanced

well types and completions such as multilateral (ML), Intelligent Well Completions (IWC), and Inflow Control Valves (ICV) will be evaluated and adopted where applicable.

4.2 Development Strategy

This section discusses the base case depletion plans for the JDA reservoir of the Hebron Field.

The depletion strategy balances resource recovery, uncertainty management and overall development flexibility to allow the reservoirs to be effectively managed over the life of the field. The depletion plan is developed through simulation studies which evaluate options such as oil recovery potential, risk, and availability of injection fluids, among other considerations. This plan is dynamic and will evolve as new information about the reservoir, its geology, and degree of heterogeneity becomes available through drilling of new wells and production-injection history.

The base case depletion plan for the JDA reservoirs includes a total of 16 development wells (10 producers and 6 water injectors), of which only 6 wells (4 producers and 2 water injectors) are associated with this DPA. The Development Plan does not include gas injection or any other gas related depletion mechanisms such as water-alternating-gas injection due to the higher subsurface pressure of the reservoir which would require addition of surface compression equipment. The Operator will continue to test the potential for other development strategies to optimize reservoir performance as new information becomes available.

The well placement philosophy gives primary consideration 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 and resources.

The depletion plan relies primarily on dedicated standalone wells targeting sands with the most potential and least risk. For the sands which cannot justify dedicated wells, the potential for commingled wells will be evaluated. 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 the learnings obtained during the development drilling program and early production performance.

Detailed individual sand development strategies are presented in the subsequent subsections.

4.2.1.1 Pool 4H Development Strategy

Pool 4H base development scenario involves providing pressure support to the reservoir by means of water injection. The preliminary well count for depleting this resource consists of three dedicated producers and three water injectors. This is in addition to the existing L93 22 smart well also producing from the H Sand reservoir interval. The total number of wells may change due to a number of factors. These factors include, but are not limited to, the following:

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

There are currently two Pool 4H development wells: the H Sand interval in L93-22 and the recently drilled L-93 30z horizontal oil producer. The 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 in L-93 22. Assessment of L-93 30z productivity and connectivity is ongoing.

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. Further optimization of this plan is on-going and will influence final well count, well type and placements.

4.2.1.2 G, F and D Development Strategy

The current depletion plan for G, F and D reservoirs 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. These factors include, but are not limited to, the following:

1. Results of on-going activities to improve reservoir description, improve well placement and the forecasted recovery efficiency;
2. Learnings gathered during drilling through these sands;
3. Learnings gathered during early production performance from these sands;
4. Synergies between commingling strategy and overall reservoir management;
    a. Strategy considerations: reservoir drive, fluid types, pressure regime, differential depletion, drawdown management etc.
5. Decisions on advanced/smart completions technology implementation, ICV for zonal production control;
6. Opportunity to drill and complete advanced well types such as multilaterals;
7. Slot management;
8. Opportunity for pressure management via commingled water injection;
9. Opportunity to further delineate, appraise and develop more sands.

4.2.1.3 Pool 4E Development Strategy

The base depletion plan for Pool 4E consists of one production well supported by one water injection well targeting the Main Segment of the Horst Block. This is in addition to the existing L93 22 smart well also producing from the E Sand interval. The Pool 4E production will initially be through the existing L-93 22 intelligent well completion. The water injector is planned to be initiated prior to bringing L-93 22 E Sand interval back online, to provide pressure support. The 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 good reservoir quality area.

Another consideration in the E Sand development strategy is the interpreted connection between 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 direct impact on the final number of wells required to develop this resource.

4.2.1.4 Pool 4C Development Strategy

The current depletion plan for Pool 4C 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.

4.2.1.5 Pool 4B Development Strategy

Pool 4B base depletion scenario includes drilling three development wells – two producers and one injector - to target the lower sand package in the Main segment of the Hebron Horst Block. 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 and based on performance data, the final well count, well type and locations may change.

4.2.2 Development Area

The JDA development area is shown in Figure 4-1. The development area covers the entire JDA Formation. The justification for considering the development of the entire JDA Formation is based on faulting and juxtaposition relationships that have potential cross fault communication. Thus, the entire JDA Formation area including the Main, Ramp, NE Segment and adjacent fault blocks: A', B', C', D', E' and F') are included in the development area.

The details of individual sand development areas and proposed well layout is presented in the following subsection.

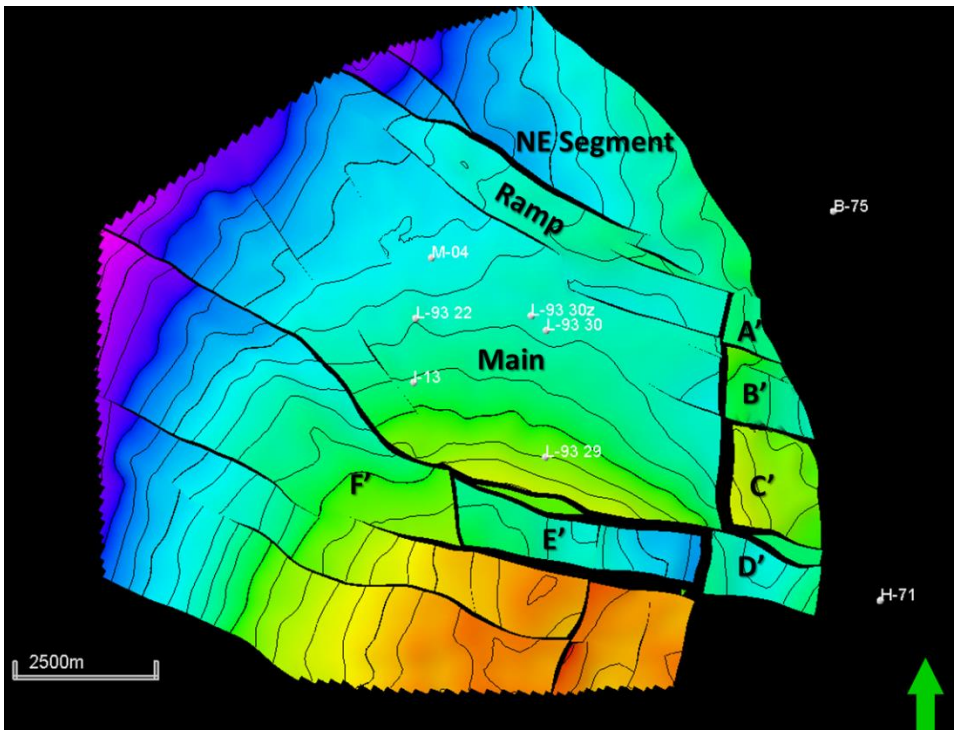


Figure 4-1: Jeanne d'Arc Development Area

4.2.2.1 Pool 4H Development Area

The JDA Pool 4H Sand development area is shown in Figure 4-2. The development area covers three segments, Main, Ramp and NE Segment. The current base depletion plan is overlain on the reservoir area showing a producer/injector pair in each segment. The targets represent a proposed well layout with further optimizations based on reservoir learnings and detailed well planning.

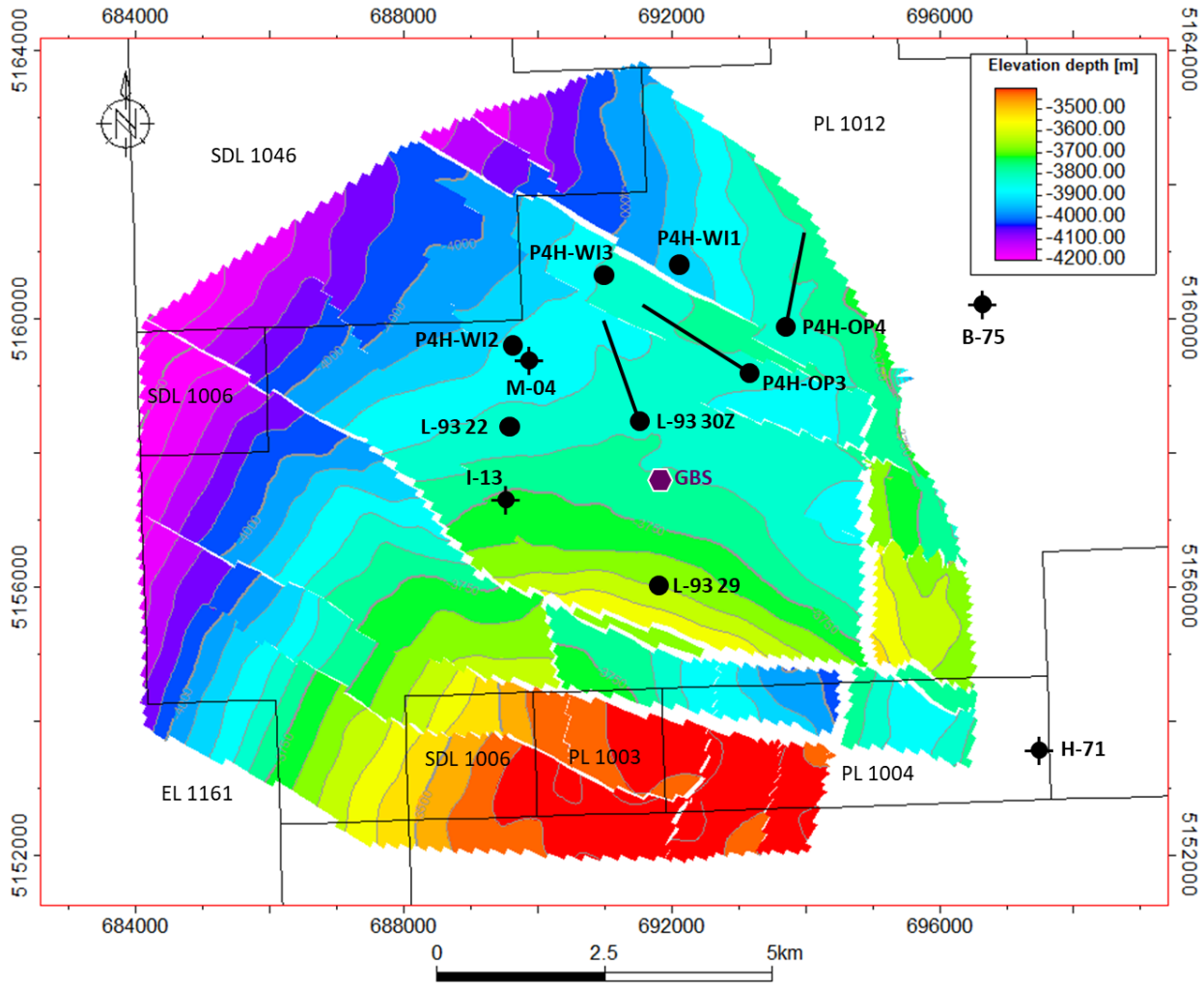


Figure 4-2: Pool 4H Sand Development Area

4.2.2.2 G, F and D Development Area

The JDA G, F and D sands development area is shown in Figure 4-3. The development area covers only the Main Segment. The current base depletion plan is overlain on the reservoir area showing a single comingled producer targeting the three sands. The target represents a proposed well layout with the number and well location optimized throughout the development period as dictated by field performance and improved understanding of reservoir description and connectivity.

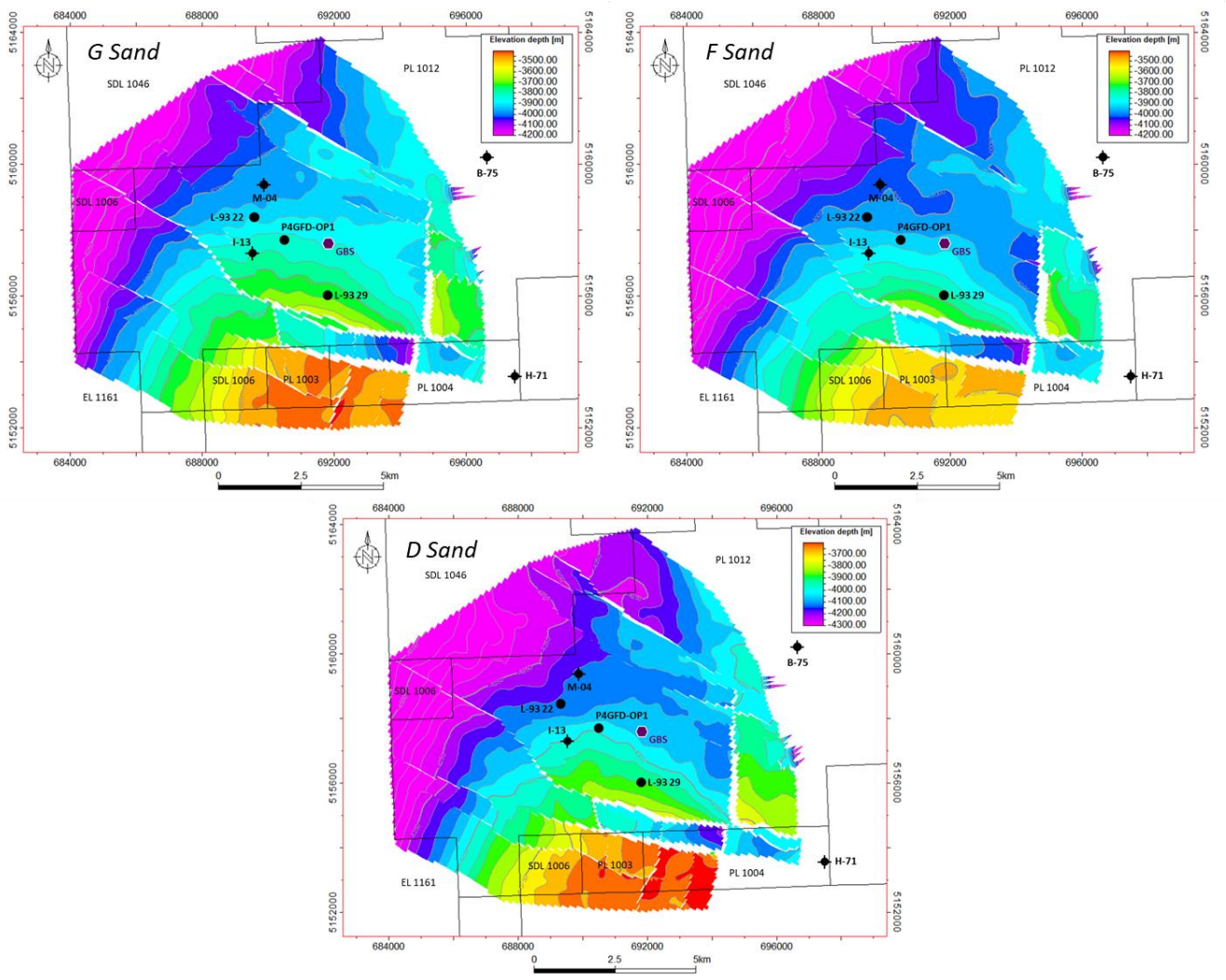


Figure 4-3: Pool 4GFD Sand Development Area

4.2.2.3 Pool 4E Development Area

The JDA Pool 4E Sand development area is shown in Figure 4-4. The current base depletion plan targets the Main Segment. This is based on high confidence of encountering productive reservoir due to proximity to existing and future well control. Remaining segments of the horst block would be evaluated for future development as knowledge of static and dynamic reservoir behavior evolve.

Potential targets for a single producer and water injector are shown on the maps. Similar to the sands described above, the final well placement and well count will be optimized as new data become available.

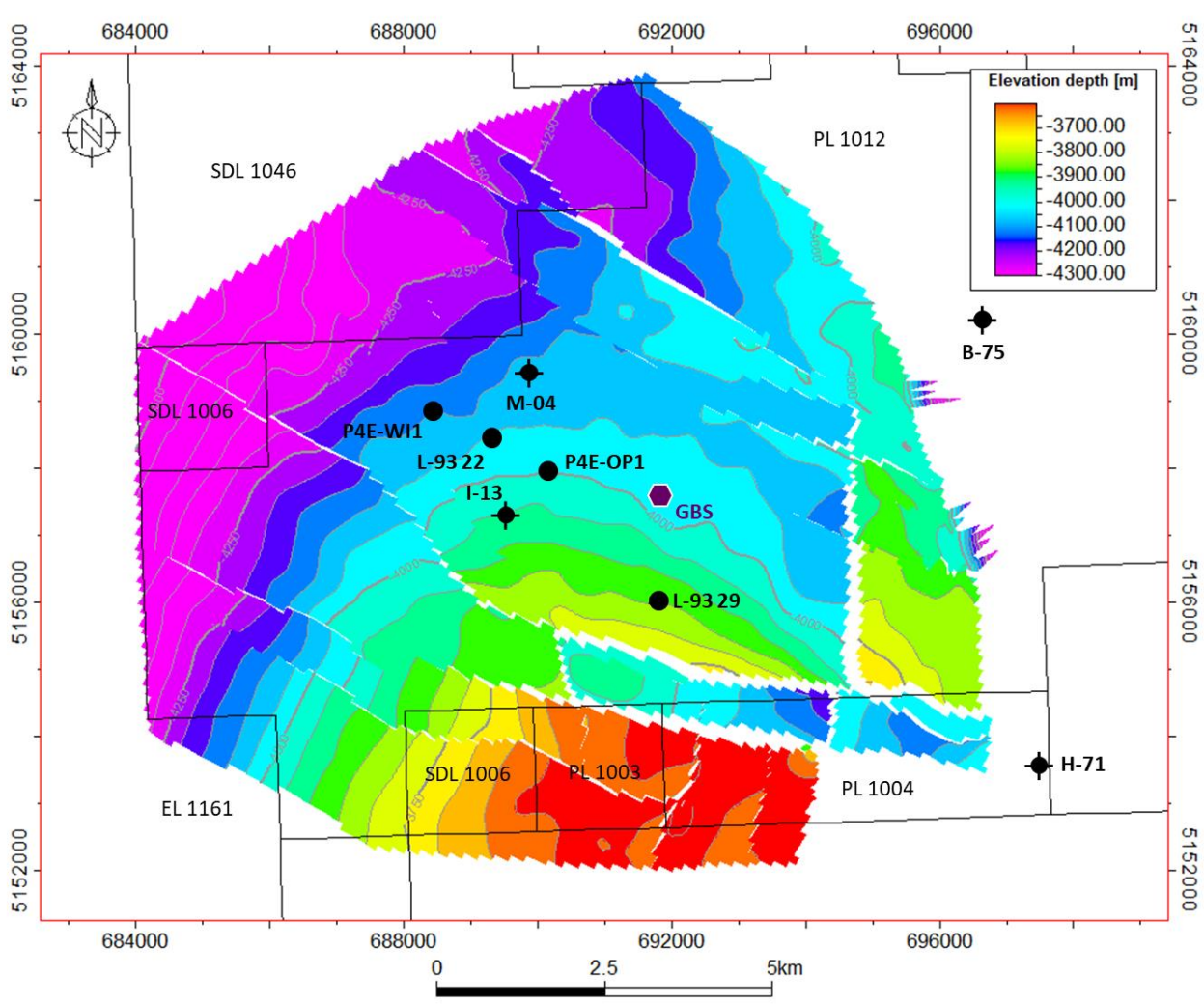


Figure 4-4: Pool 4E Sand Development Area

4.2.2.4 Pool 4C Development Area

The JDA Pool 4C Sand development area is shown in Figure 4-5. The base development scenario shows the well count and placement overlain on a map of the reservoir development area. The current base depletion plan targets the upper sand package in the Main Segment of the Hebron Horst block. The placement represents a proposed well layout and will be optimized as new data become available.

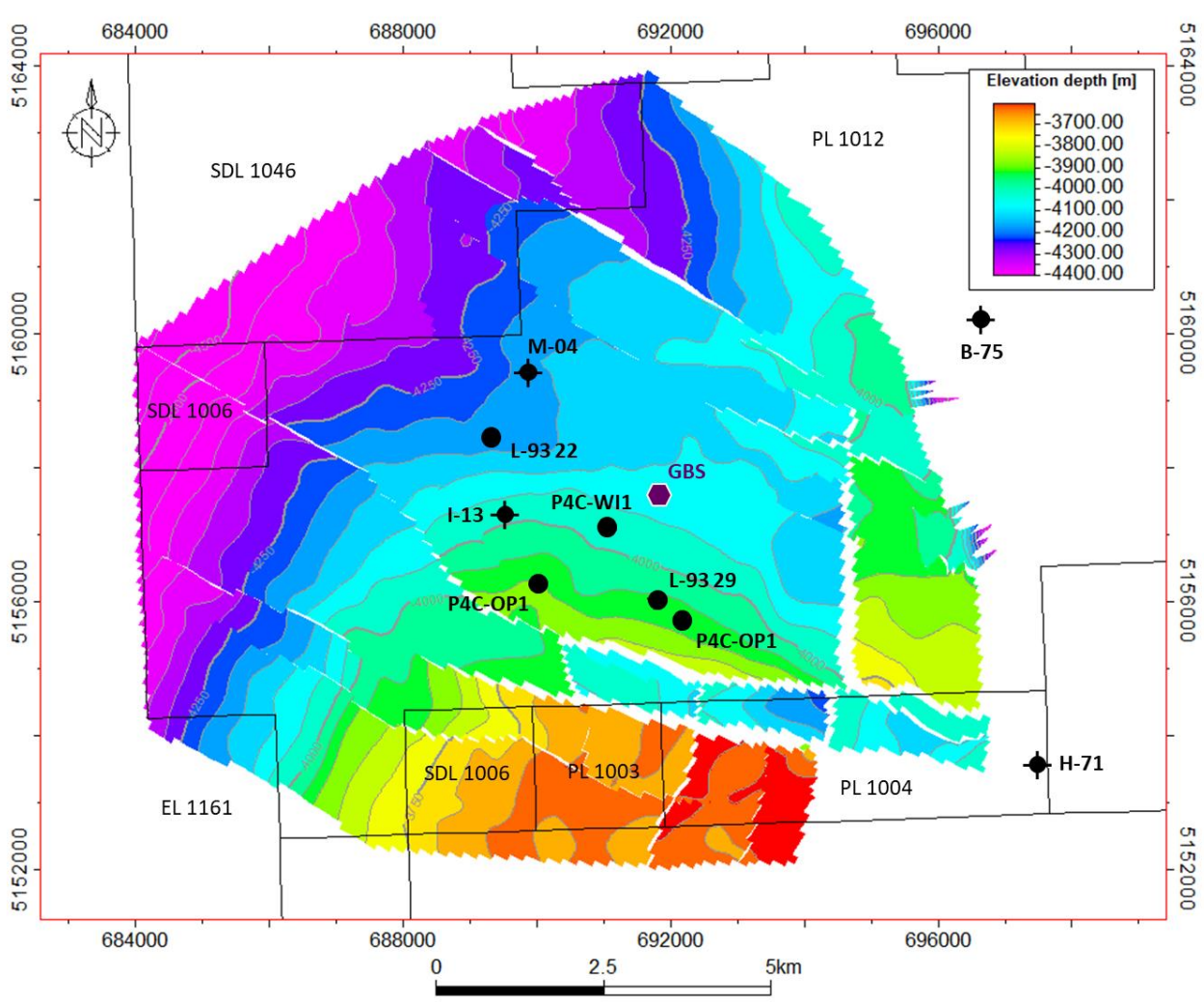


Figure 4-5: Pool 4C Sand Development Area

4.2.2.5 *Pool 4B Development Area*

The JDA Pool 4B Sand development area is shown in Figure 4-6. The current base depletion plan targets the lower sand package in the Main Segment. Potential targets for two producers and one water injector are posted on the map. Optimization of the depletion plan will continue as new data become available.

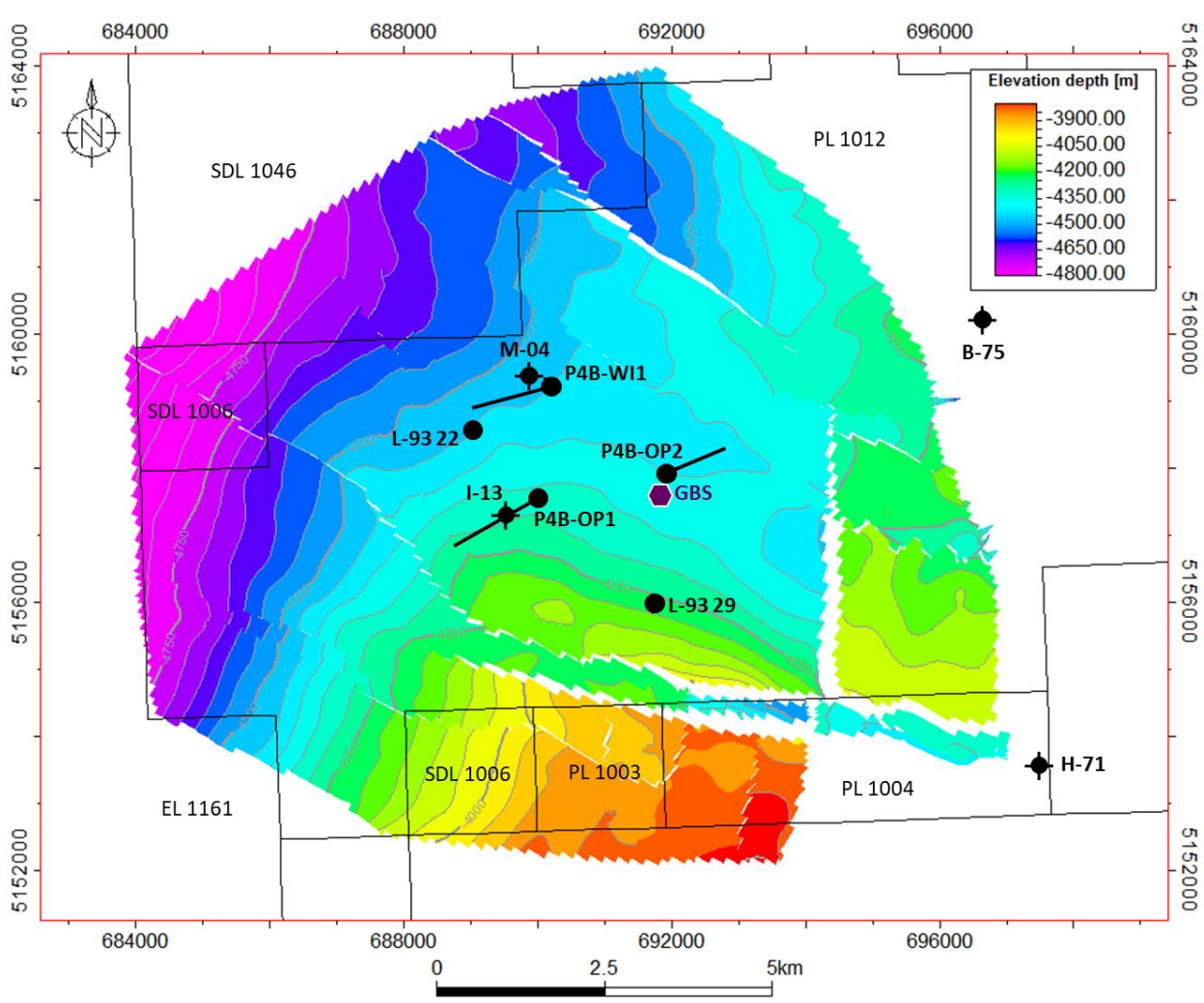


Figure 4-6: Pool 4B Sand Development Area

4.2.3 Well Placement

The JDA well placement philosophy gives primary consideration to reservoir quality and achievement of both high well productivity and high sweep efficiency. Production and injection wells will be drilled to target the best appraised highest-confidence resource. Well targets will continue to be refined as additional information is gathered to develop the remaining resources.

With respect to well orientation, the approach is to drill all wells within the established Hebron Asset well orientation practices. Further improvements will be made as additional learnings on stress directions and faulting are incorporated.

4.2.4 Well Count

The depletion plan for the JDA resource includes drilling 16 development wells, of which 6 development wells are associated with this DPA. This plan is based on simulation modeling and information gathered

to date. In addition, at the individual sands level, the number of planned development wells is driven by the remaining recoverable resource.

The proposed well counts represent the current best estimate of the wells required to optimally deplete the resources targeted in the depletion plan. The well counts are subject to change with future depletion planning optimizations resulting from on-going and future simulation studies, acquisition of new or reprocessing of existing seismic data, results of initial development drilling activities, production performance data, etc.

4.2.4.1 Pool 4H Well Count and Sensitivities

The depletion scenario for Pool 4H is a six-well program, three producers and three water injectors. This scenario is based on simulation modeling and constrained by slot availability. Further optimization of well count, well type and layout is expected.

Preliminary sensitivity studies on well count indicate potential to improve recovery. The results, shown in Figure 4-7 suggest the potential to increase recovery from the H Sand reservoir through an additional horizontal well in the Main segment. The graph also shows individual segment recovery. Realizing this recovery potential is part of the continued effort to improve subsurface understanding and well placement risks.

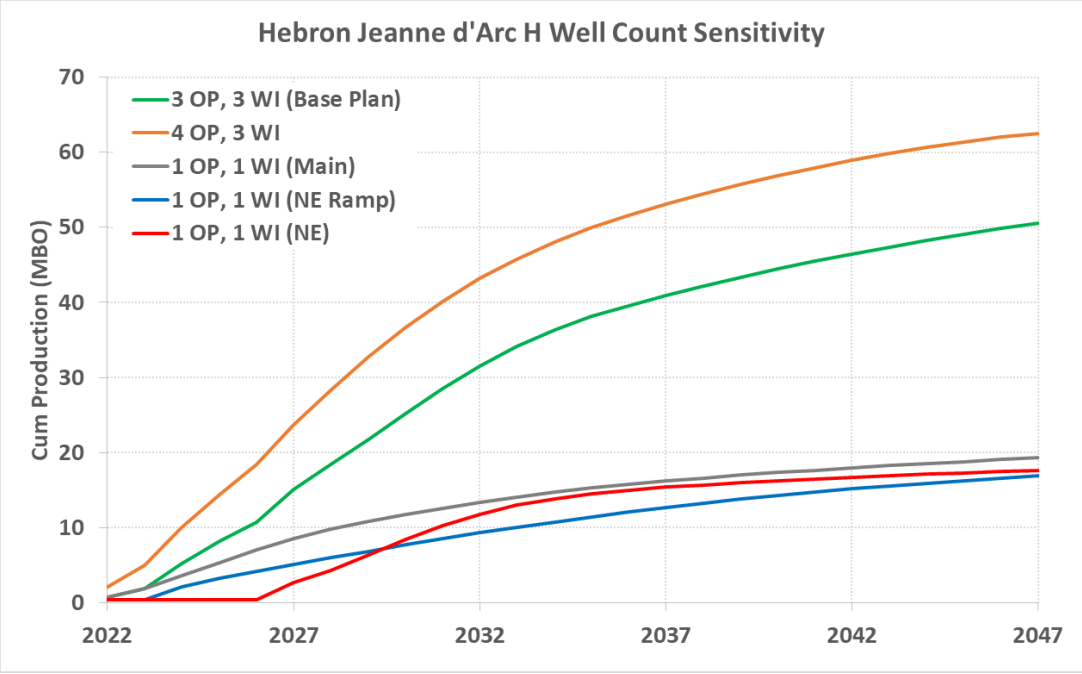


Figure 4-7: Pool 4H Sand Well Count Sensitivity
OP = Oil Producer; WI = Water Injector

The base depletion scenario assumes developing the pool with highly deviated to horizontal producers to provide optimum well-to-reservoir contact. An alternate well type with vertical producer wells was considered. As shown in Figure 4-8, vertical well development oil recovery was found to be suboptimal both in terms of rate and recovery. Similar to the existing L-93 22, vertical well development might be considered if the opportunity to develop the H Sand reservoir with other JDA reservoirs through commingled production/injection exist. Future work on commingle strategy and opportunity will be key in shaping the decision on vertical well development of the H Sand reservoir.

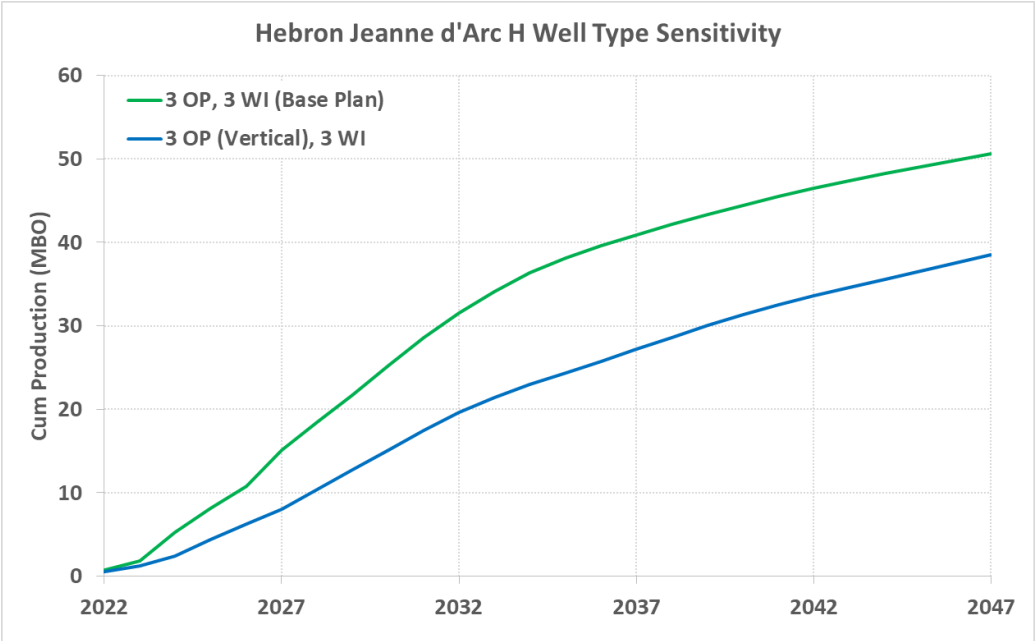


Figure 4-8: Pool 4H Sand Well Type Sensitivity
OP = Oil Producer; WI = Water Injector

4.2.4.2 G, F and D Sand Well Count and Sensitivities

The current depletion plan for the JDA G, F and D reservoir sands involves a single-well program. This plan is based on simulation modeling and constrained by slot allocation. The basis will evolve with learning gathered during development drilling as reservoir and geological understanding is matured.

Preliminary sensitivity studies conducted on well type and alternate depletion mechanism indicate potential opportunities to improve recovery. The result, shown in Figure 4-9, indicates the potential to increase recovery through development with highly deviated wells, especially for the dominant producing sand (G sand). Optimization of other sands performance will be based on continued improvements in subsurface understanding and reservoir performance.

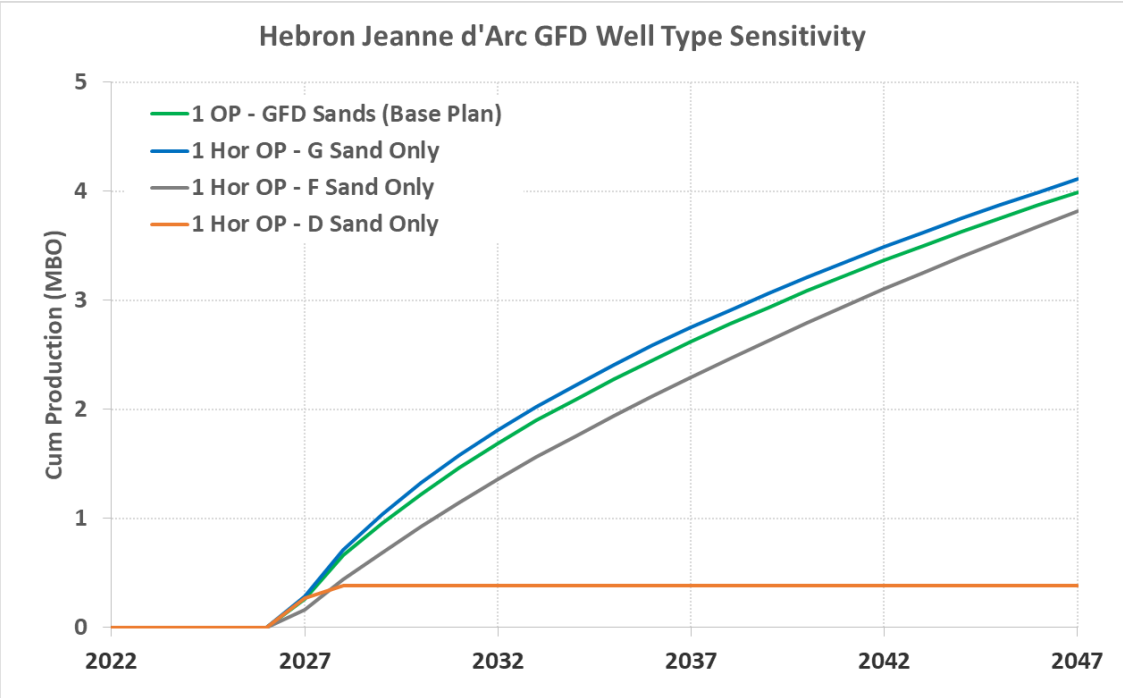


Figure 4-9: Pool 4GFD Sand Well Type Sensitivity
OP = Oil Producer; WI = Water Injector; Hor OP = Horizontal Oil Producer

4.2.4.3 Pool 4E Well Count and Sensitivities

The Pool 4E depletion scenario is based on a three-well development program, one dedicated well pair and existing zonal production from L-93 22. This scenario is based on simulation modeling and constrained by slot availability. Further optimization of well count, well type and layout is expected as improvement in reservoir and geologic behavior matures.

Preliminary sensitivity studies conducted on well count and well type reveal potential opportunities to improve recovery. The results, shown in Figure 4-10 and Figure 4-11, indicate the potential to increase recovery from the E Sand reservoir by both increasing the number of dedicated wells drilled but also varying the type of wells to include both deviated and horizontal wells. The feasibility of these sensitivities will be depending on learnings from the reservoir. Additionally, the opportunity to concurrently develop this sand with other sands through commingled production and/or injection will be a key development consideration with the potential to influence the decision on the final well type.

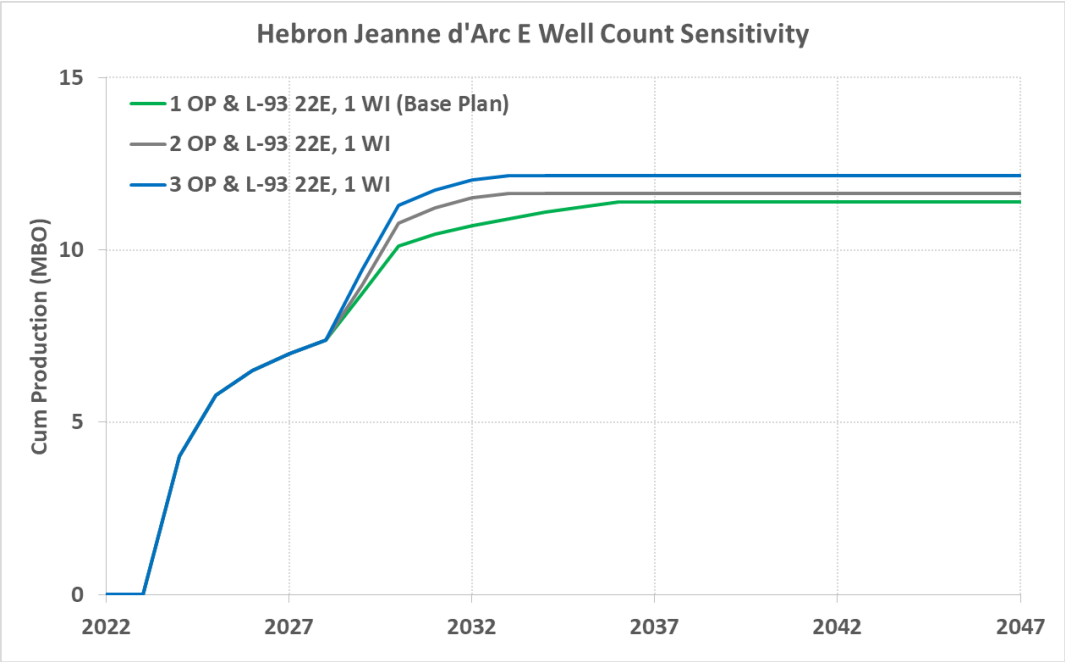


Figure 4-10: Pool 4E Sand Well Count Sensitivity

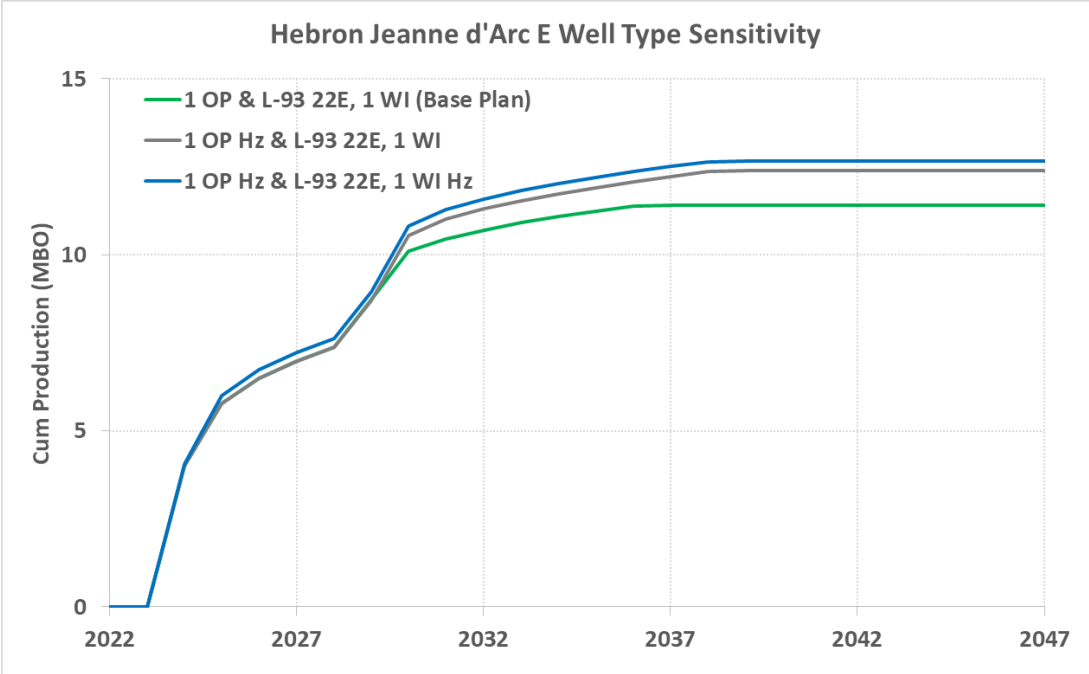


Figure 4-11: Pool 4E Sand Well Type Sensitivity
OP = Oil Producer; WI = Water Injector; OP Hz = Horizontal Oil Producer

4.2.4.4 Pool 4C Well Count and Sensitivities

The depletion scenario used to support the development of the C Sand reservoir is a three-well program, two vertical producers and one vertical injector. This scenario is based on simulation modeling and constrained by slot availability. Further optimization of well count and well type is expected as improvement in reservoir and geologic behavior matures.

Figure 4-12 shows the results from well count sensitivities studies conducted on C Sand reservoir. The results indicate the potential to increase recovery from the C Sand reservoir through additional drilling.

Results from the proposed development wells will be used evaluate the potential of the sensitivity studies.

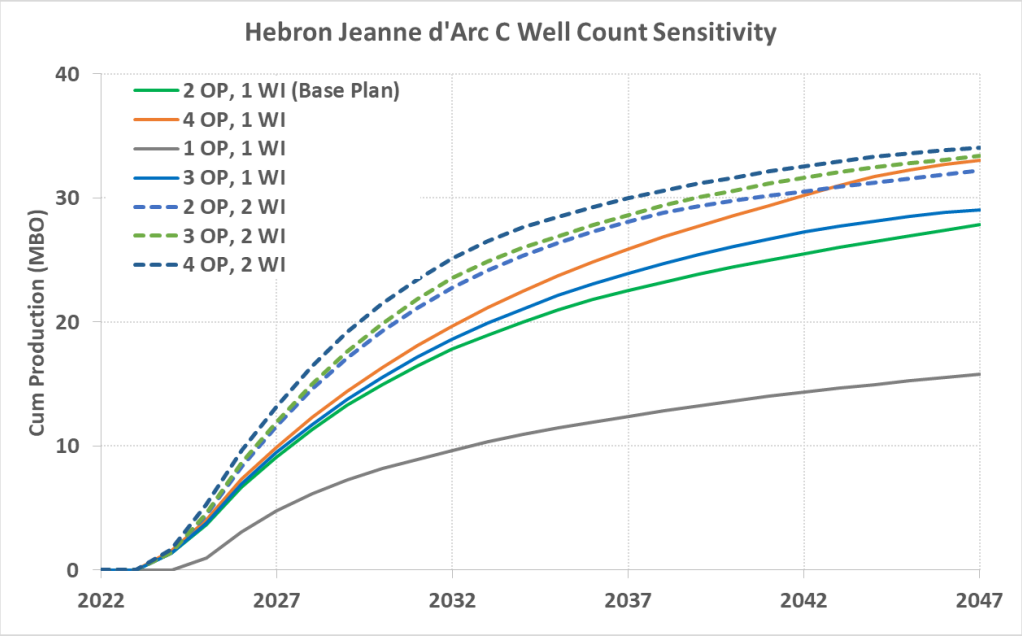


Figure 4-12: Pool 4C Sand Well Count Sensitivity

While the base depletion scenario assumes developing the pool with vertical wells, sensitivity studies conducted on other types of wells, including deviated and horizontal wells indicate potential opportunities to improve recovery and field performance. The results, shown in Figure 4-13, indicate the potential to increase recovery from the C Sand reservoir through developing with alternate well types.

The current option to develop C sand with vertical wells is premised on the following considerations:

- A wide range of uncertainty in C Sand performance expectations based on lack of dynamic C Sand data
- A deviated well design provides flexibility to gather additional static data for the full JDA formation and influence future well designs
- A deviated well design will assist with assessment of vertical connectivity within the C Sand to better optimize a future horizontal well if assessed as the best depletion option
- Horizontal wells have more planning and execution complexity. A deviated wellbore can provide greater certainty in execution, however; the Operator will continue to apply lessons learned to planning and execution of horizontal wells.

The Operator will continue to evaluate and optimize the C sand depletion plan as new information becomes available

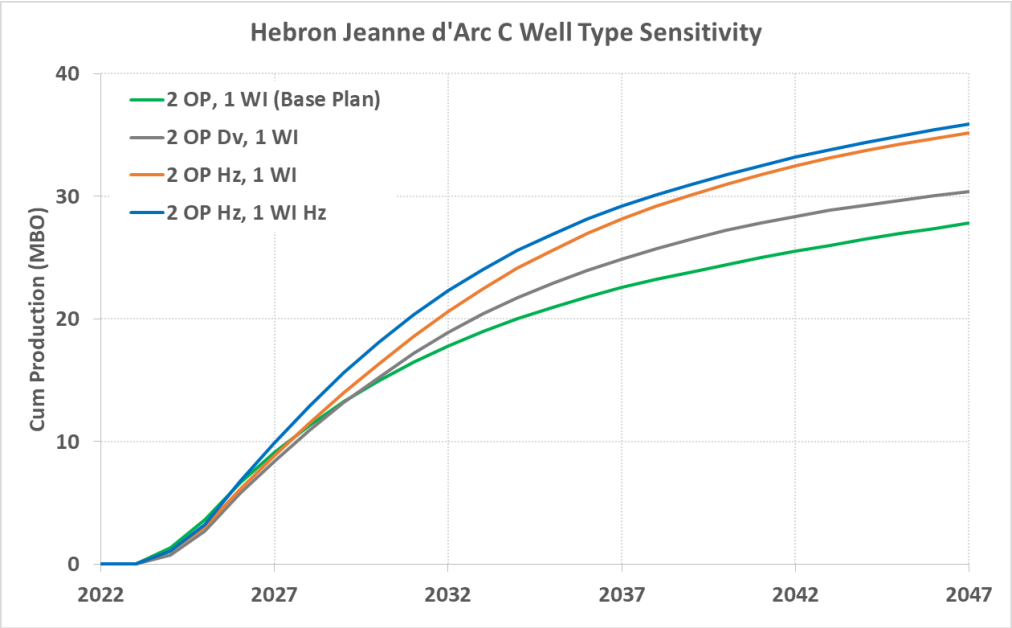


Figure 4-13: Pool 4C Sand Well Type Sensitivity
OP = Oil Producer; WI = Water Injector; OP Hz = Horizontal Oil Producer; WI Hz = Horizontal Water Injector

4.2.4.5 Pool 4B Well Count and Sensitivities

The current depletion plan for the JDA Pool 4B reservoir involves a three-well program (two development producers and one water injector). This plan is based on simulation modeling and slot allocation. The basis will evolve with learning gathered during the development drilling as reservoir and geological understanding is matured.

Well count sensitivity studies were conducted to evaluate the potential for increasing recovery by increasing the well density. The results, shown in Figure 4-14, indicate the potential to increase recovery from the B Sand reservoir. Realizing this recovery potential will be based on ongoing studies aimed at reducing the uncertainty in reservoir description and connectivity as well as results from early wells drilled into the B Sand reservoir.

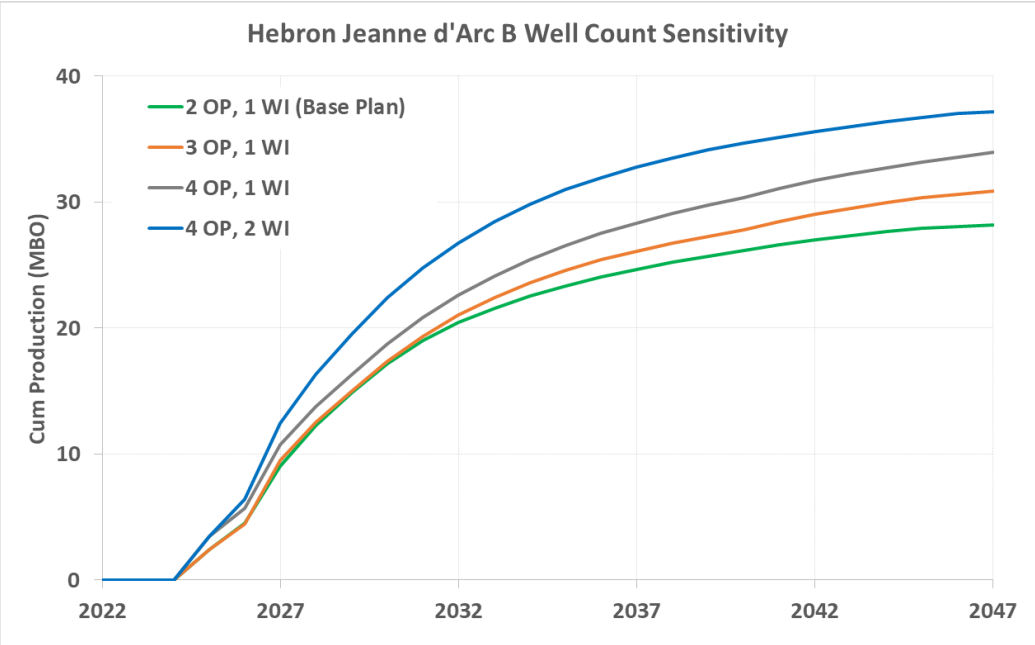


Figure 4-14: Pool 4B Sand Well Count Sensitivity

Similarly, results from well type sensitivity studies provided in Figure 4-15 support developing B Sand reservoir with highly deviated/horizontal wells. While development with horizontal wells is desired from a resource recovery perspective, the feasibility of successfully drilling a high angle horizontal well in B Sand reservoir is uncertain. Further studies and learnings from initial development drillings will play a key role in de-risking horizontal well drilling.

Alternatively, vertical well development is another consideration for B Sand reservoir development. The advantage of this option over horizontal well development is the opportunity to concurrently develop the sand with other sands through commingled production/injection.

Therefore, the feasibility of drilling horizontal well and the benefit commingling multiple sands will be key in determining the final well type required to develop this sand.

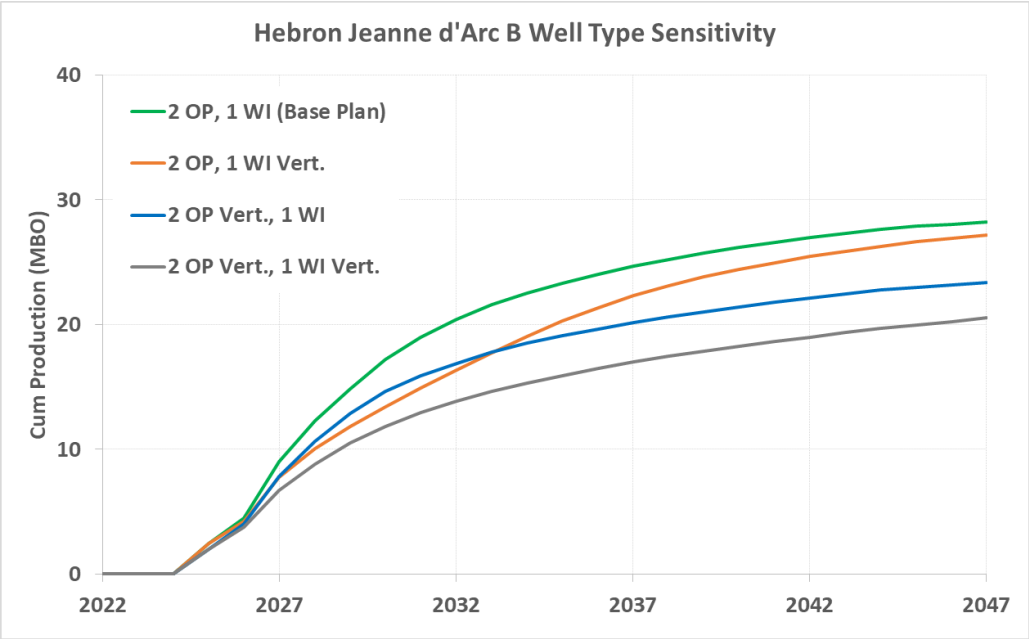


Figure 4-15: Pool 4B Sand Well Type Sensitivity
OP = Oil Producer; WI = Water Injector; OP Vert = Vertical Oil Producer; WI Vert = Vertical Water Injector

4.2.4.6 Fault Blocks A' through F'

The development wells target the Hebron Horst but additional wells into the rimming faults blocks (A' through F') are also considered. The development and timing of these fault blocks will be informed by learnings from the Hebron Horst block, including static (reservoir presence and quality expectations), contact expectations and dynamic (such as production time scale connectivity to existing wells).

4.2.5 Drilling and Completions

The below subsections reference Drilling and Completions considerations for development in the JDA formation and constitute amendments to Section 7.0 of the Development Plan.

4.2.5.1 Development Drilling JDA specific amendments:

At present, it is forecasted that 51 wellbores will be utilized to exploit the Hebron resource base. The JDA development is anticipated to require 16 total wellbores, 6 of which are incremental to the initial B and H Sand development plan.

4.2.5.2 Preliminary Drilling and Completion Plans JDA specific amendments:

Wellbores associated with the JDA development will have three dimensional trajectories and may require extended reach drilling profiles. Multilateral well designs may also be considered in future.

Completions designs will be determined on a well-by-well basis and may include both cased and open hole configurations. The addition of sand control technologies will also be considered where deemed required. Concepts will be refined and finalized during detailed well design.

4.2.5.3 Cuttings Re-Injection

Performance of cutting re-injection will continue to be carefully monitored. This surveillance includes analysis of fracture containment, injectivity rates, total actual and anticipated injection volumes. As required, alternate geological formations may be identified for future non-aqueous fluid (NAF) based cuttings and waste fluid disposal.

Dedicated injection wellbores will remain the primary conduit of cutting re-injection to assigned formations, with the potential for future operation in open annuli of water injection wellbores to provide an alternate option.

4.2.5.4 Wellbore Hole and Casing Program JDA specific amendments

Conductor casing setting depths are expected to remain consistent across the Hebron pools, inclusive of the JDA formation. Surface casing will generally be set deeper than Pool 1 offsets, at 500 – 700 mTVD / mMD.

Table 4-1: Preliminary Well Hole Size and Casing Program (JDA DPA)

Casing Size/Type	Hole Size[2]	Preliminary Material Specification[1][5]	Connection Specification	Est. Setting Depth RKB[3] [4]
762 mm Conductor	838 mm	X-65	X-65 XLW (or similar)	± 300 m TVD ± 300 m MD
508 mm Surface	610 mm	X-65	X-65 XLW (or similar)	500 - 700 mTVD / mMD
340 mm Intermediate	432 mm or 445 mm	95 – 125 KSI API Grade	Premium Connection	2000 – 2500 mTVD 2000 – 3200 mMD
244mm or 273 mm x 244 mm Production	311 mm	100 – 125KSI API and Proprietary Grades	Premium Connection	3800 – 4000 mTVD 3800mMD +
Open or cased hole completion(s) [6]	216 mm	80 – 125KSI API and Proprietary Grades	Premium Connection	3900 – 4800 mTVD 3900mMD+
140 mm/178 mm Production Tubing	Inside Production Casing	80 – 125KSI API and Proprietary Grades	Premium Connection	3800 – 4000 mTVD 3800mMD +
Other (Liner)	Various	80 – 125KSI API and Proprietary Grades	Premium Connection	Various

Notes

1) Material specifications to be refined during detailed well design

2) Hole interval may be required to be opened to meet drilling and / or completions design requirements

3) RKB = Rotary Kelly Bushing (elevation reference)

4)TVD = True Vertical Depth, MD = Measured Depth

5) KSI = Thousand pounds per square inch

6) Multilateral well designs may include two or more completion intervals

4.2.5.5 Conductor / Surface Hole Sections JDA specific amendments

For wellbores in the JDA formation, large diameter top hole section diameters will be either 838mm (Conductor) or 610mm (Surface) and will typically be drilled using water-based (water polymer) drilling fluid systems. The surface casing setting depth for wellbores will be between 500 – 700mMD / mTVD, and the final setting depth for the 508mm surface casing will be evaluated on a well-by-well basis and communicated via the individual Approval to Drill a Well (ADW) process.

4.2.5.6 Intermediate Casing JDA specific amendments

For development within the JDA formation, the intermediate casing string (340mm) will be set and cemented in a 432mm or 445mm hole at approximately 2000 – 2500 m TVD. The intermediate hole section may include a liner interval as a base or contingent design, to be assessed during detailed well design. This hole section will be drilled with either water-based (water polymer) or NAF-based drilling fluids.

4.2.5.7 Production Casing JDA specific amendments

The production casing will consist of a 244mm casing string or a 273mm x 244mm tapered casing string. The final setting depths for the production casing will be determined on a well-by-well basis to meet well design objectives. The 273mm casing may be run to below the hydrate formation depth (800 - 1000mMD) to accommodate large diameter tubing retrievable surface-controlled subsurface safety valves (TRSCSSV).

Further details of the production hole section will be determined during detailed well design. These details may include underreaming hole section to improve drillability, or/and the inclusion of a liner interval as a base or contingent design. The production hole section will typically be drilled with NAF-based drilling fluids.

4.2.5.8 Reservoir Section JDA specific amendments

A 216mm hole is planned to be drilled through one or more of the productive reservoir intervals and may be opened to accommodate completions designs or to improve drillability.

Further details of the reservoir hole section will be assessed on a well-by-well basis and determined during detailed well design. These details include completion types (either cased or open hole completion), and consideration of technology application such as sand control, or multilateral well designs involving two or more reservoir sections. The reservoir hole section will typically be drilled with NAF-based drilling fluids.

4.2.5.9 Directional Drilling JDA specific amendments

Directional planning will be critical in delivering directional profiles that satisfy the well objectives and intersect the specified reservoir targets at the designated coordinates. Anti-collision operations outlined in existing procedures will be utilized for the drilling of the platform wellbores. The directional plans should allow management of doglegs to minimize sideforces thus reducing casing wear potential and maximizing drilling efficiency (i.e. Rate of Penetration (ROP), on-bottom drilling).

Rotary steerable devices will be the primary means of achieving the desired well path. Gyros and MWD technology will be applied as appropriate to monitor the progress of the directional plan while drilling, provide feedback, and allow modification of the planned profile to ensure all objectives are satisfied.

Learnings from previous Eastern Canada wellbores (Hebron, Hibernia, and Terra Nova) related to directional responses in the region will be maximized. Directional profiles for platform-based wellbores will be assigned once final slot selection has been determined.

Preliminary wellpaths have been developed. Updates to the trajectory planning will be performed as and when reservoir targets are better defined. The preliminary JDA spider plot in Figure 4-16. illustrates the two existing oil producer well paths (L-93 22 and L-93 30Z) as well as the potential planned six water injector and 8 additional oil producer well paths in the Jeanne D'Arc.

See Section 5.3 for additional information on well count and sequence.

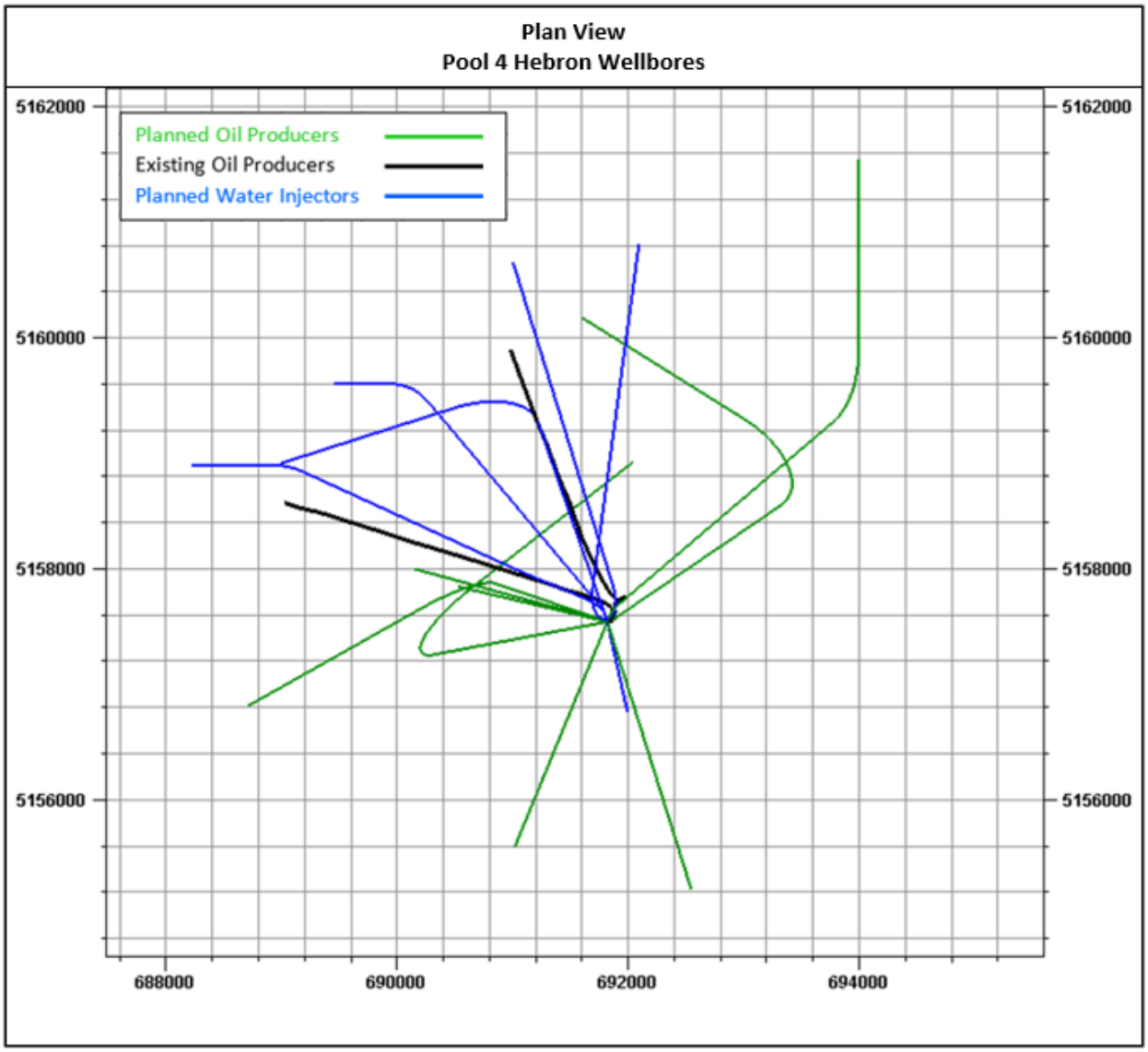


Figure 4-16: Preliminary JDA Spider Plot

4.2.5.10 Cement JDA specific amendments

Annular pressure buildup (APB) in the wellbore casing will be addressed during well design and will be mitigated either through casing and cementing program design and / or annulus pressure management systems and processes at surface.

Table 4-2: Preliminary Cementing Program (JDA DPA)

Casing	Slurry Type[4]	Planned Top (Meters MD RT)[1]	Thickening Time (Hours)	Target Slurry Density (kg/m^3) [4]	Excess %	Mix Water Type
Conductor	Class "G" single slurry or lead tail.	GBS bottom/ seafloor	Planned job time + 1 Hr	1560 lead 1880 tail	Gauge + 150%	Drill Water +Sea Water
Surface	Class "G" single slurry or lead tail.	Surface	Planned job time + 1 Hr	1300 – 1560 lead 1880 tail	Gauge + 100% Gauge + 100%	Sea Water
Intermediate [2]	Class "G" single slurry or lead tail.	Isolate hydrocarbon containing intervals. Typically 200m above South Mara	Planned job time + 1 Hr	1600 lead 1865 tail	Gauge + 30% Gauge + 30%	Sea Water
Production[2]	Class "G" single slurry or lead tail.	Isolate hydrocarbon containing intervals. Typically Below previous shoe	Planned job time + 1 Hr	1670 lead 1900 tail	Gauge + 15% Gauge + 15%	Drill Water
Reservoir[3]	Class "G"	Liner top, target ~100m liner lap fully cemented	Planned job time + 1 Hr	1900	Gauge + 15%	Drill Water

Notes

1) MD RT = Measured Depth Rotary Table elevation reference
2) Stage cementing tools may be used in this interval; slurry design(s) for stage cementing to be determined during detailed well design
3) Applicable to cased hole completions
4) Slurry designs will be finalized during detailed well design and may include the use of slurry extenders

4.2.5.11 Completion Overview JDA specific amendments

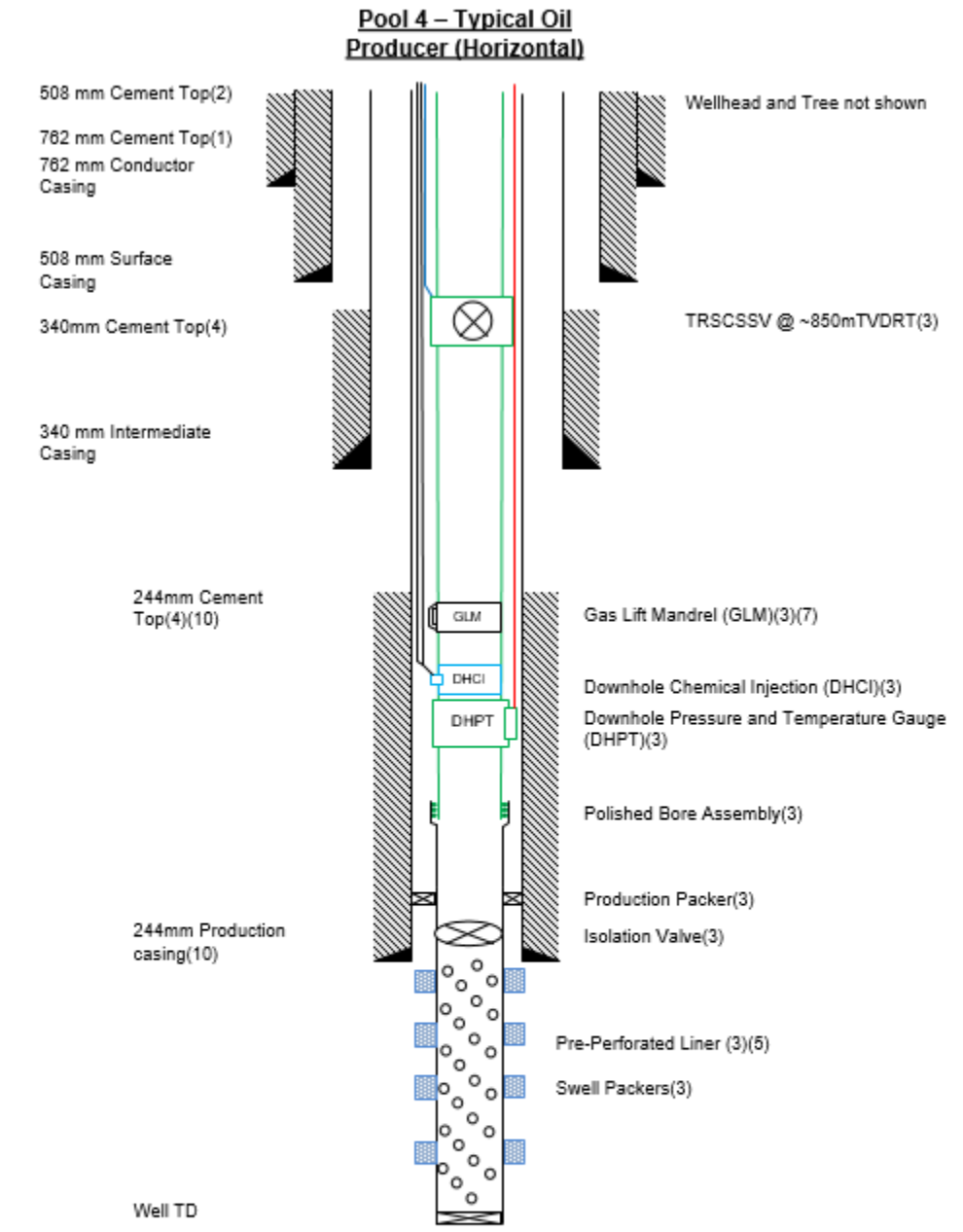
Design for wellbores specific to JDA development may consider both cased and open hole completions. Sand control is not currently anticipated as a requirement for Pool 4 but will be assessed on a well-by-well basis during detailed completions design.

4.2.5.12 Completion Objectives JDA specific amendments

Well schematics for typical Pool 4 oil producers and water injectors can be referenced below.

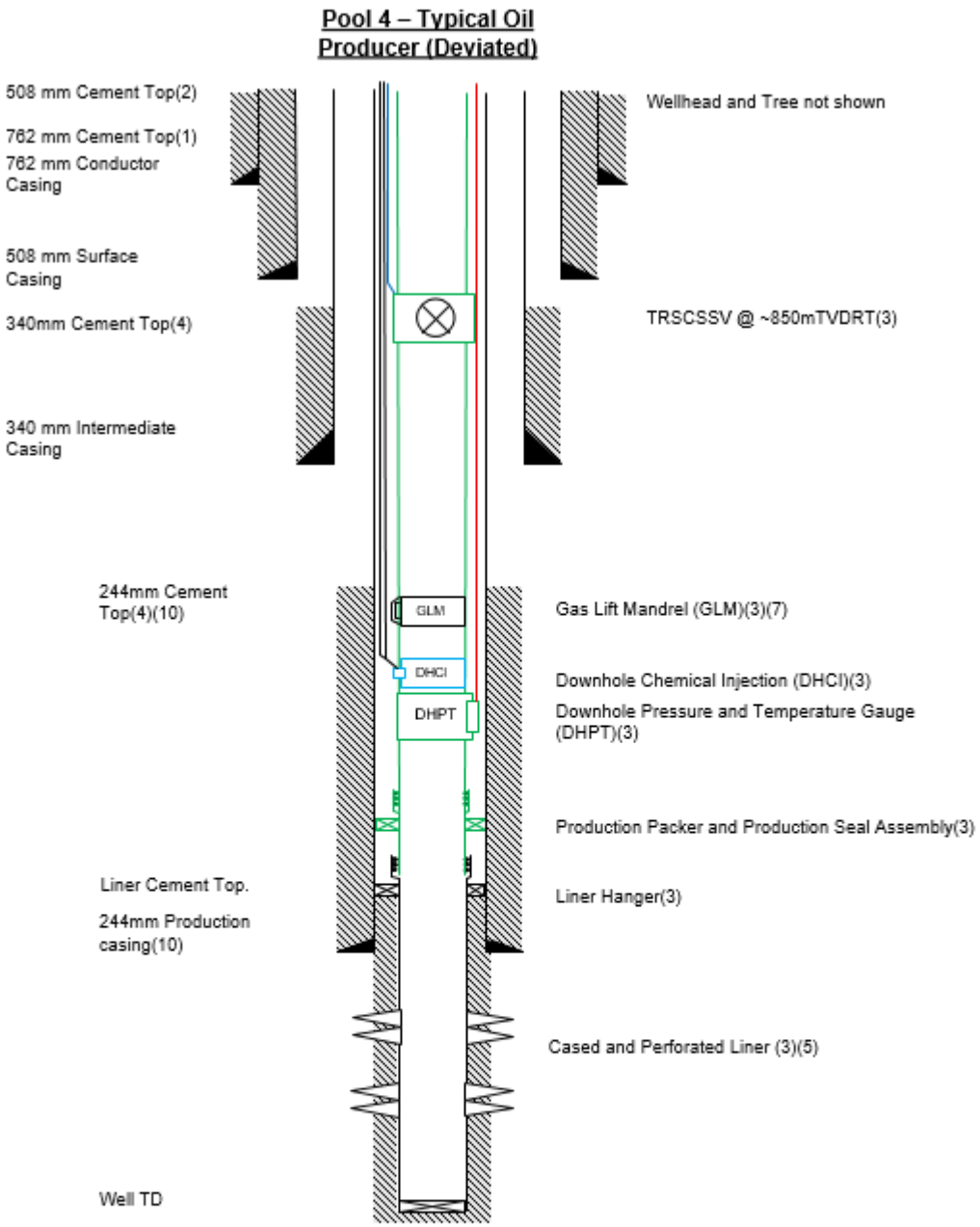
Completions designs will typically include 178 mm and / or 140 mm tubing with premium connections and application appropriate sealability envelopes. Permanent down-hole pressure and temperature gauges will be included in oil producers and may be included in water injectors, minimizing well intervention requirements for reservoir monitoring purposes. Where gas lift is required, completion designs will be evaluated to compare the use of ASVs, barrier qualified gas lift valves, and / or other available technology to ensure that the overall risk of the well and platform remains as low as reasonably practicable. ExxonMobil confirms that barrier qualified gas lift valves have been evaluated as a supplement to the Hebron Quantitative Risk Assessment (QRA) and that use of a conventional ASV will be resumed should it be determined that use of barrier qualified gas lift valves negatively impacts QRA results.

While there are a variety of completion options available, cased and perforated or open hole completions with pre-perforated liner and swell packers are the primary candidate for Hebron Pool 4 wellbores.



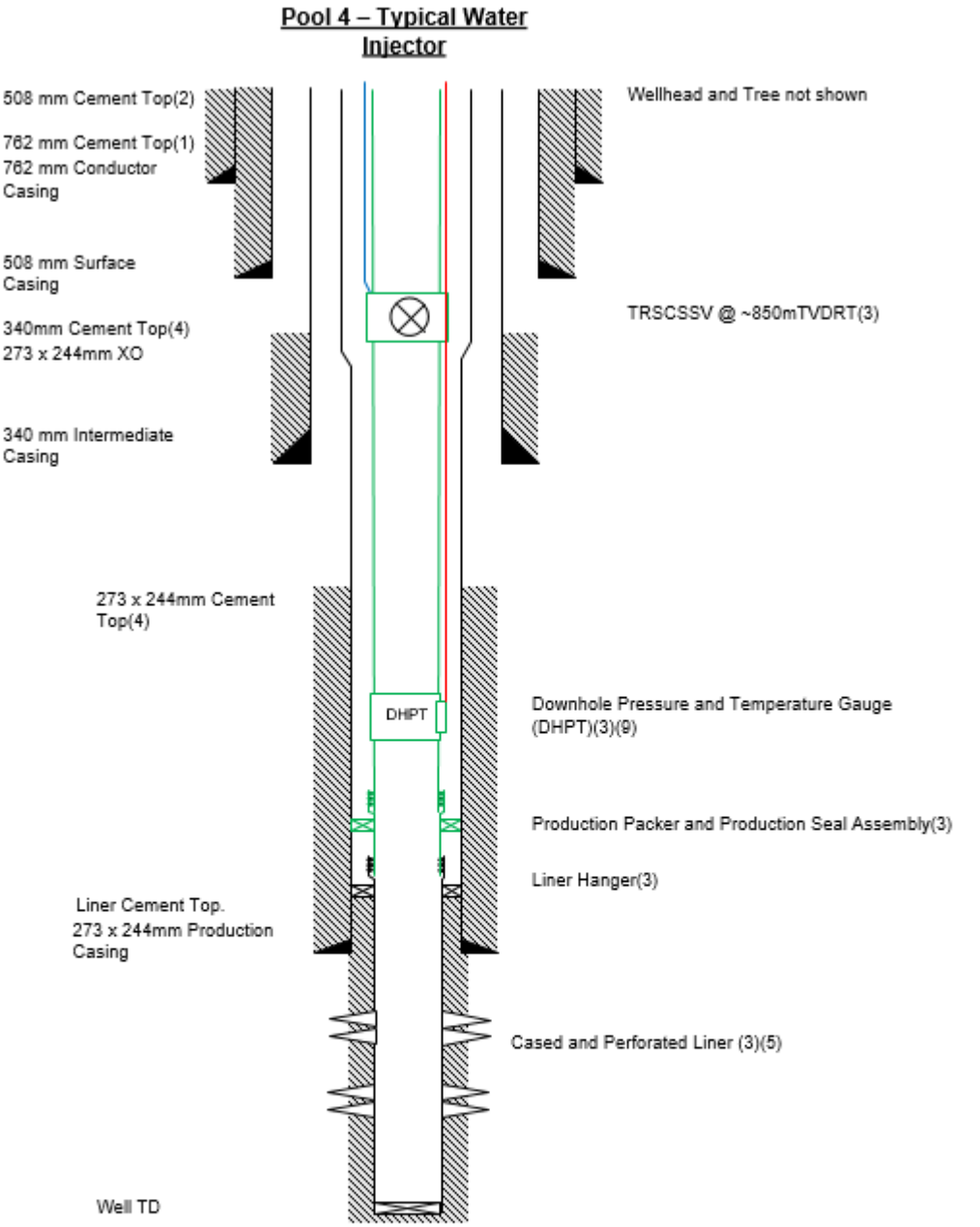
Notes:
(1) – Conductor cement top at GBS bottom / seafloor
(2) – Surface casing cement top at surface
(3) – Other completion designs may be required, to be evaluated during detailed well design.
(4) – Cement top may be inside previous casing shoe, to be evaluated during detailed well design.
(5) – Multilateral well designs may also be evaluated during detailed well design
(6) – Wells may include additional liner intervals, to be determined during detailed well design.
(7) – One or more gas lift mandrels as required based on detailed well design.
(8) – Wells illustrated assume no sand control requirement, to be evaluated during detailed well design.
(9) – DHPT gauges are optional in water injectors.
(10) – Tapered (273x244 mm) casing strings may be used on oil producers, to be evaluated during detailed well design

Figure 4-17: JDA specific Oil Producer schematic – horizontal well



Notes:
(1) – Conductor cement top at GBS bottom / seafloor
(2) – Surface casing cement top at surface
(3) – Other completion designs may be required, to be evaluated during detailed well design.
(4) – Cement top may be inside previous casing shoe, to be evaluated during detailed well design.
(5) – Multilateral well designs may also be evaluated during detailed well design
(6) – Wells may include additional liner intervals, to be determined during detailed well design.
(7) – One or more gas lift mandrels as required based on detailed well design.
(8) – Wells illustrated assume no sand control requirement, to be evaluated during detailed well design.
(9) – DHPT gauges are optional in water injectors.
(10) – Tapered (273x244 mm) casing strings may be used on oil producers, to be evaluated during detailed well design

Figure 4-18: JDA specific Oil Producer schematic – deviated well



Notes:
(1) – Conductor cement top at GBS bottom / seafloor
(2) – Surface casing cement top at surface
(3) – Other completion designs may be required, to be evaluated during detailed well design.
(4) – Cement top may be inside previous casing shoe, to be evaluated during detailed well design.
(5) – Multilateral well designs may also be evaluated during detailed well design
(6) – Wells may include additional liner intervals, to be determined during detailed well design.
(7) – One or more gas lift mandrels as required based on detailed well design.
(8) – Wells illustrated assume no sand control requirement, to be evaluated during detailed well design.
(9) – DHPT gauges are optional in water injectors.
(10) – Tapered (273x244 mm) casing strings may be used on oil producers, to be evaluated during detailed well design

Figure 4-19: JDA specific Water Injector schematic

4.2.5.13 Multi-Function Wellbores JDA specific amendments

No JDA specific changes, no Multi-Function wellbores are planned for the JDA.

4.2.5.14 Completion Fluids JDA specific amendments

No JDA specific changes to completion fluids are noted.

4.2.5.15 Wellbore Safety Systems JDA specific amendments

Where gas lift is required, completion designs will be evaluated to compare the use of ASVs, barrier qualified gas lift valves, and / or other available technology to ensure that the overall risk of the well and platform remains as low as reasonably practicable. ExxonMobil confirms that barrier qualified gas lift valves have been evaluated as a supplement to the Hebron Quantitative Risk Assessment (QRA) and that use of a conventional ASV will be resumed should it be determined that use of barrier qualified gas lift valves negatively impacts QRA results.

4.2.5.16 Shallow Gas Hazards JDA specific amendments

Use of diverter assembly in surface hole sections to be consistent with regulator query decision, C-NLOPB Reference: 2018-RQ-0001, EMCP Reference: RQF-HEB-073.

4.2.5.17 Hole Stability JDA specific amendments

No JDA specific changes to hole stability are noted, the Operator's integrated hole quality risk assessment methodology will continue to be used for planning fluid system designs and responding to wellbore instability issues.

4.2.5.18 Formation Pressure JDA specific amendments

Abnormal pore pressure has been observed in the G-sand interval of the JDA on P4H-OP1 (L-93 22). The primary mitigations for drilling abnormally pressured intervals is proper drilling fluid design and drilling / tripping practices. Fluid densities will be planned to mitigate against hazards associated with this overpressure interval and to maintain a hydrostatic overbalance during drilling and completions operations when required.

4.2.5.19 Differential Sticking JDA specific amendments

No JDA specific changes to differential sticking are noted.

4.2.5.20 Material Selection JDA specific amendments

No JDA specific changes to material selection are noted.

4.2.5.21 Reservoir Souring JDA specific amendments

No JDA specific changes to reservoir souring are noted.

4.2.5.22 Well Control System JDA specific amendments

No JDA specific changes to the Hebron well control system. The Hebron BOP (Blow Out Preventer) consists of 4 ram style and 1 annular style closing mechanism. All Hebron well control systems, inclusive of the BOP, choke and kill manifold, mud gas separator, trip tanks, pit volume totalizers, and flow monitoring systems meet or exceed requirements for development of the JDA resource.

4.2.5.23 Wellhead and Trees JDA specific amendments

No JDA specific changes to Wellhead or XT systems.

4.3 Well Scheduling Philosophy

The drilling schedule for development of the JDA sands considers several key objectives including maximizing initial oil rates, maximizing total recovery and acquiring data to aid further asset depletion plan optimizations. The order of development is driven by remaining recoverable resource and proposed well count of each of the individual reservoirs. The schedule assumes the drilling program is executed by the existing Hebron drilling facilities (single platform GBS rig).

Simulation models were run with well count and timing consistent with the Integrated Schedule presented in Section 5.3.

4.4 Production Profile

4.4.1 Pool 4H Sand

As shown in Figure 4-20, Pool 4H preliminary recoverable volume after 23 years of production is estimated to be 50.6 million barrels of oil (8.0 Mm3). These production profiles are direct simulation model results and do not account for downtime or the effect of any production constraints associated with the design capacity limits of the Hebron production system. The integrated development production profiles with the production processing facilities design constraints and the integrated project drilling schedule assumptions are presented in Section 5. Actual production rates are subject to change with future modeling and optimization work.

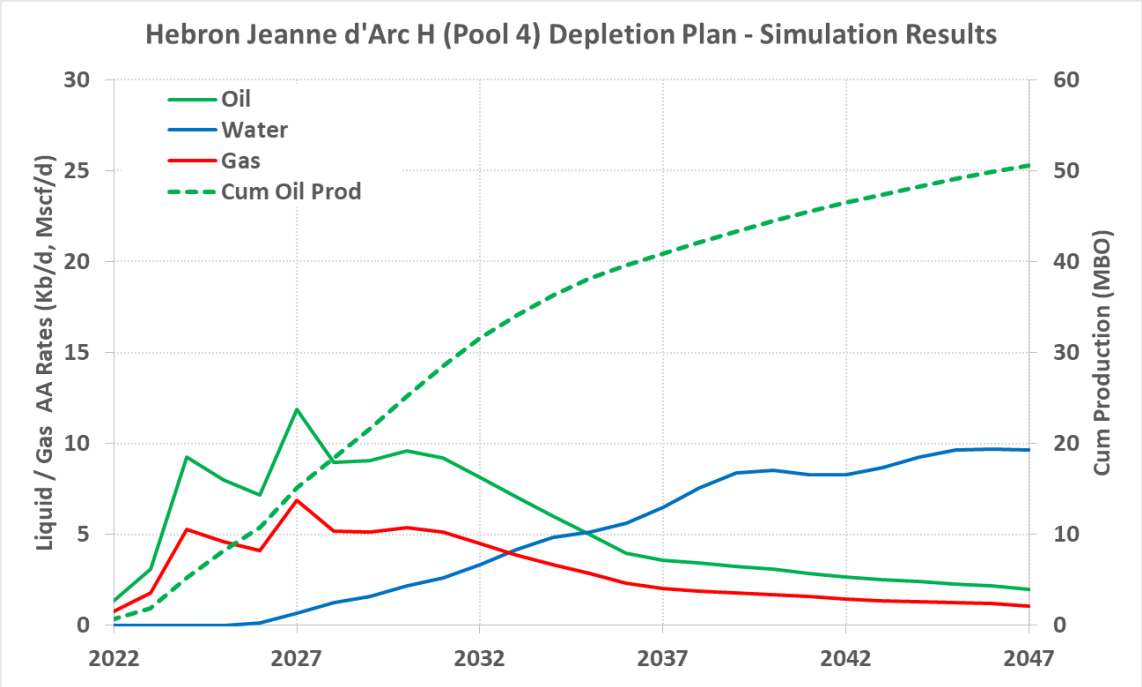


Figure 4-20: Pool 4H Sand Base Case Depletion Plan Simulation Results

An alternate depletion plan with primary recovery scheme (3 producers only) was tested. As shown in Figure 4-21, this option was found to be suboptimal for resource recovery as compared to the current depletion plan involving pressure support by water injection.

Reservoir continuity is a major uncertainty associated with this resource and effective placement of the water injection well is essential to realizing the economic benefit from the cost associated with drilling the injection well.

During the detailed well planning phase, deepening vertical water injection wells to support multiple sands in the Jeanne d'Arc Formation will be investigated. This is part of a strategy to optimize well slot utilization and oil recovery from all reservoirs.

Gas injection and other gas related mechanisms of depletion including water-alternate-gas were not considered due to the higher subsurface pressure of this resource which would require added surface compression equipment. The Operator will continue to test the potential for the addition of other development strategies to optimize reservoir performance as new information becomes available.

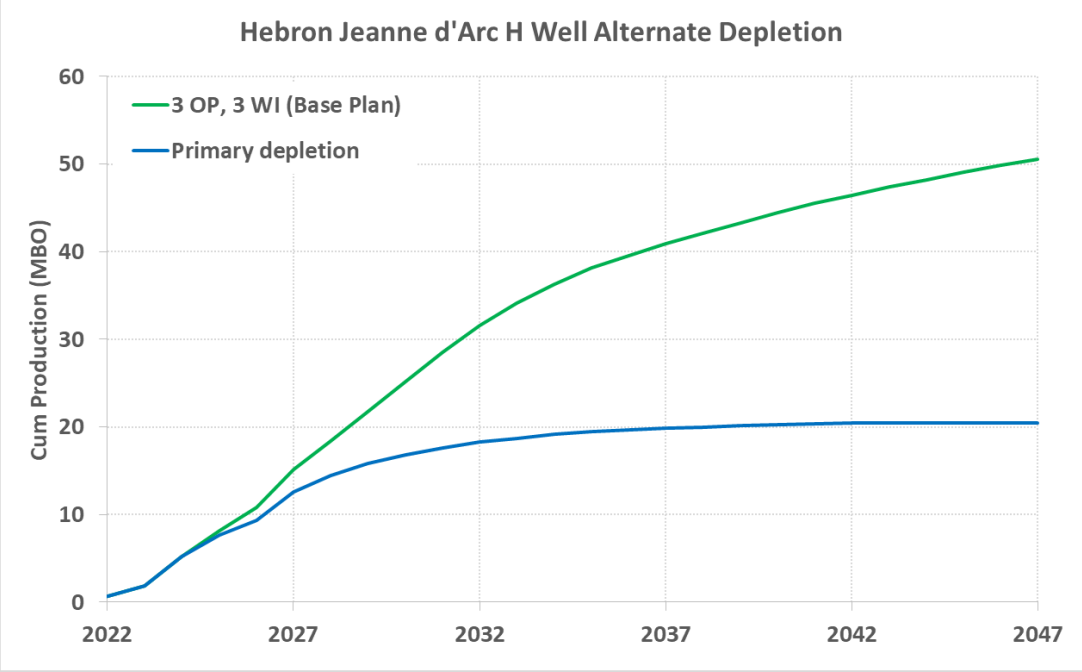


Figure 4-21: Pool 4H Sand Alternate Depletion Plan – Primary Depletion

The average reservoir pressure profiles for the three producing segments of the H Sand as a function of time are shown in Figure 4-22.

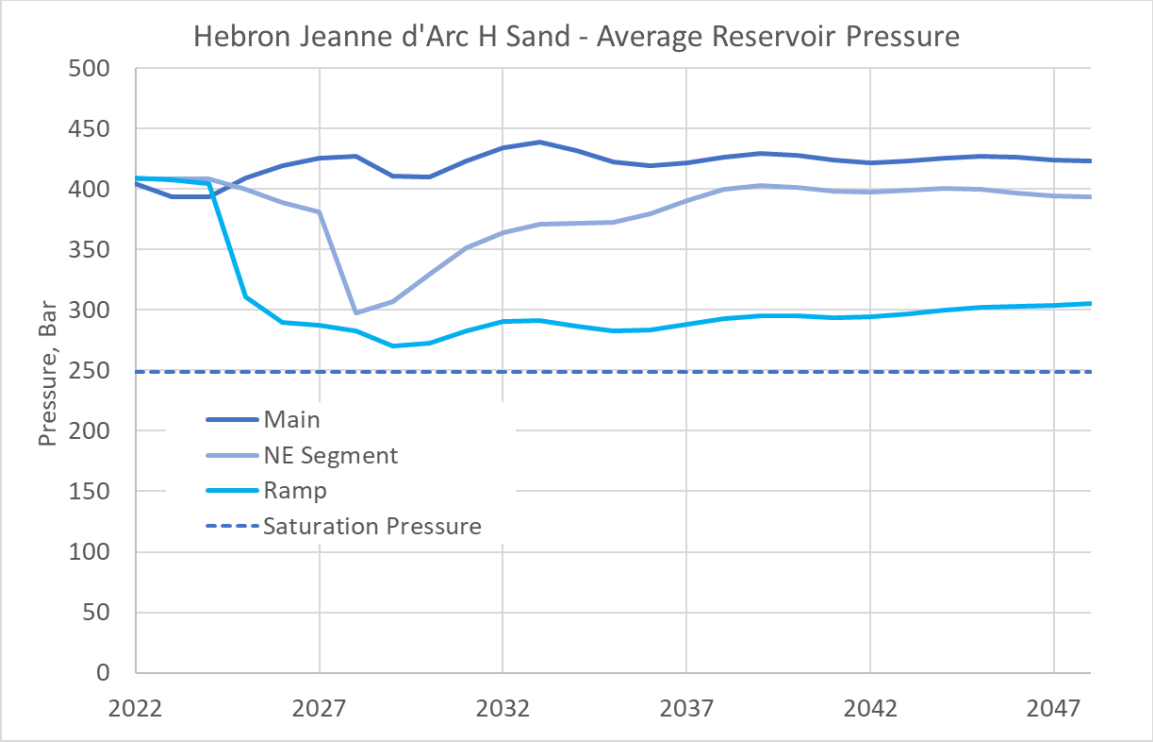


Figure 4-22: Pool 4H Sand average reservoir pressure through time.

4.4.2 G, F, and D Sand

G, F and D Sand production profiles and recovery are shown in Figure 4-23. Overall, the recoverable volume is estimated to be 4.0 million barrels of oil (0.6 Mm3). These production profiles are derived from reservoir simulation and do not include any provision for downtime, nor the effect of any production constraints associated with the design capacity limits of the Hebron production system. The combined development production profiles with the production processing facilities design constraints and the integrated project drilling schedule assumptions are presented in Section 5.

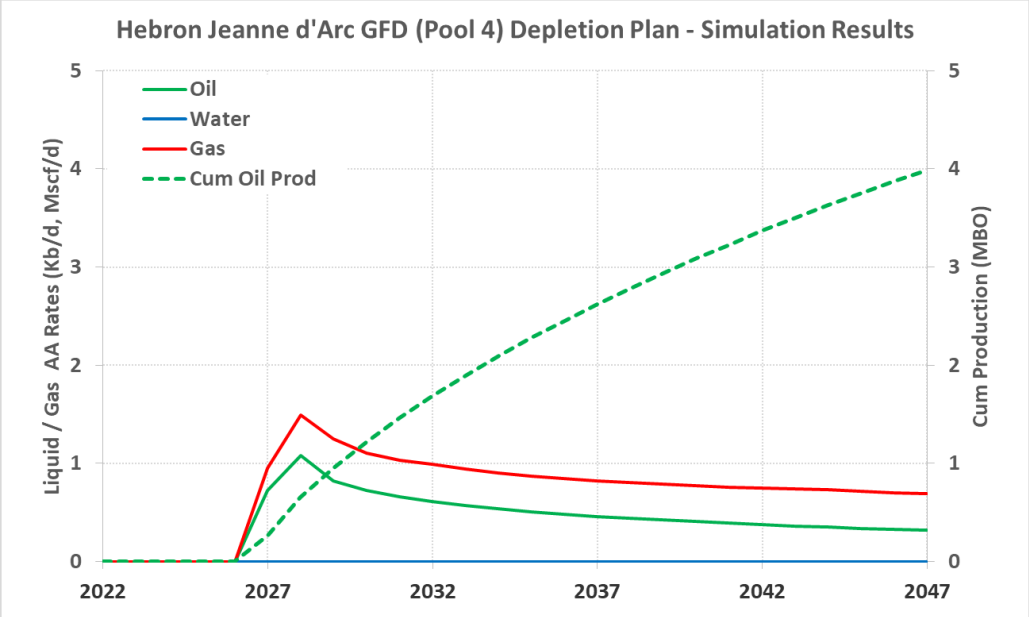


Figure 4-23: G, F and D sands Base Case Depletion Plan Simulation Results

An alternate depletion plan with water injection primarily supporting G sand was tested. As shown in Figure 4-24, this option was found to provide better resource recovery as compared to the current depletion plan involving no pressure support.

Targeting multiple sands with a single oil producer is challenging and effective placement of the water injection well is essential to optimizing pressure support and economic benefit. The operator will continue to evaluate well placement optimization.

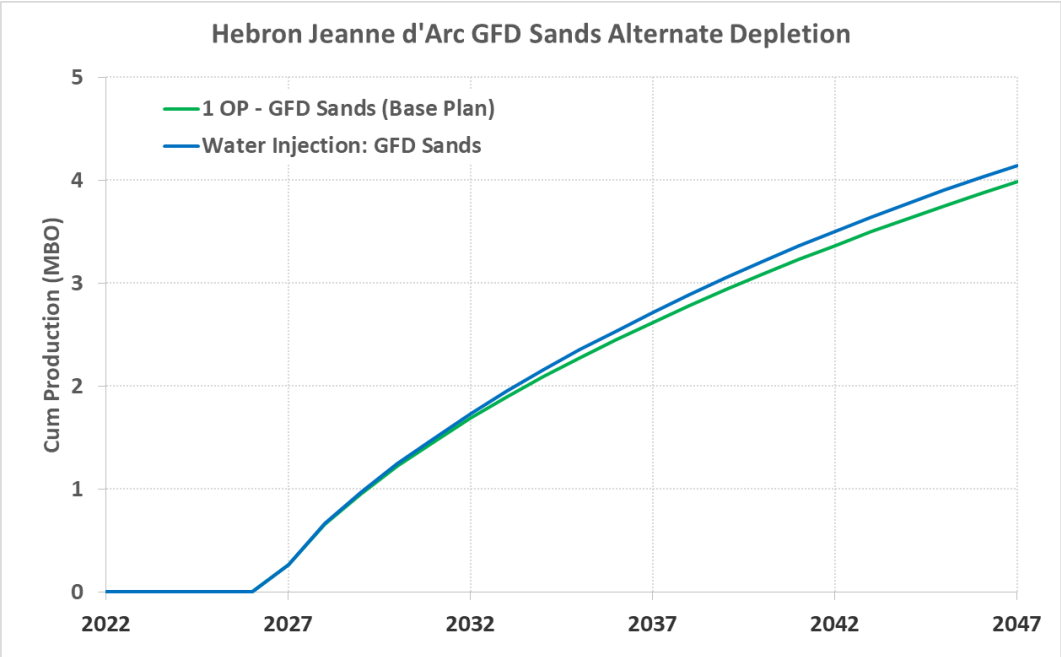


Figure 4-24: Pool 4GFD Sands Alternate Depletion Plan

The average reservoir pressure profiles for the G, F and D sands as a function of time are shown in Figure 4-25.

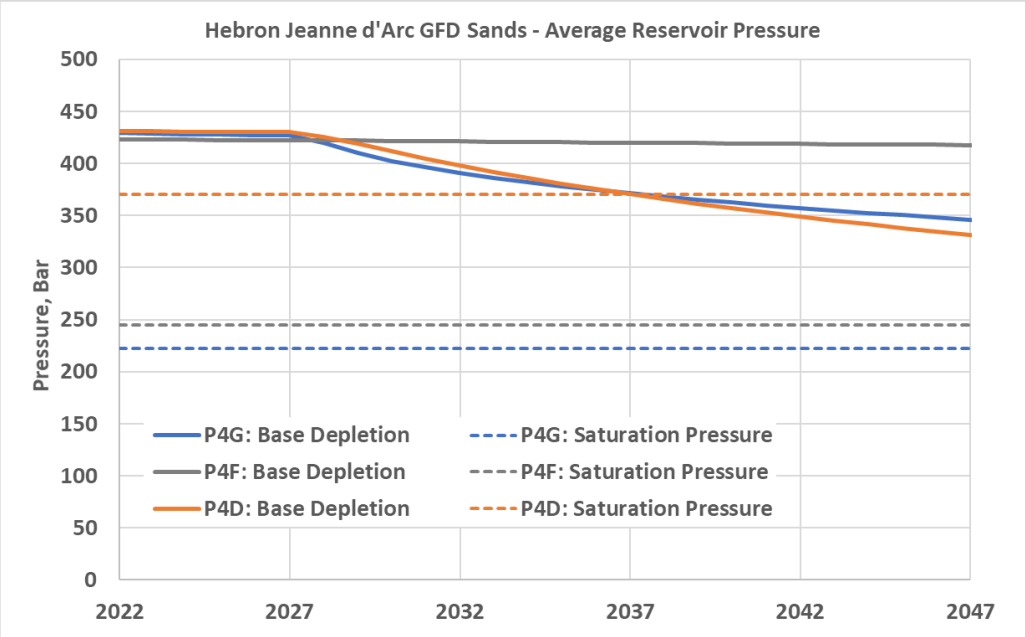


Figure 4-25: G, F and D sands average reservoir pressure through time.

4.4.3 Pool 4E Sand

Pool 4E Sand is estimated to recover 11.4 million barrels of oil (1.8 Mm3) in the base case depletion plan. The production profiles outlining the liquid and gas production profiles derived from the base case depletion plan are shown in Figure 4-26. Note that these profiles include production from the existing L-93 22 E sand.

These production profiles are supported by simulation model only and neither include any provision for downtime, nor the effect of any production constraints associated with the design capacity limits of the Hebron production system. The combined development production profiles with the production processing facilities design constraints and the integrated project drilling schedule assumptions are presented in Section 5.

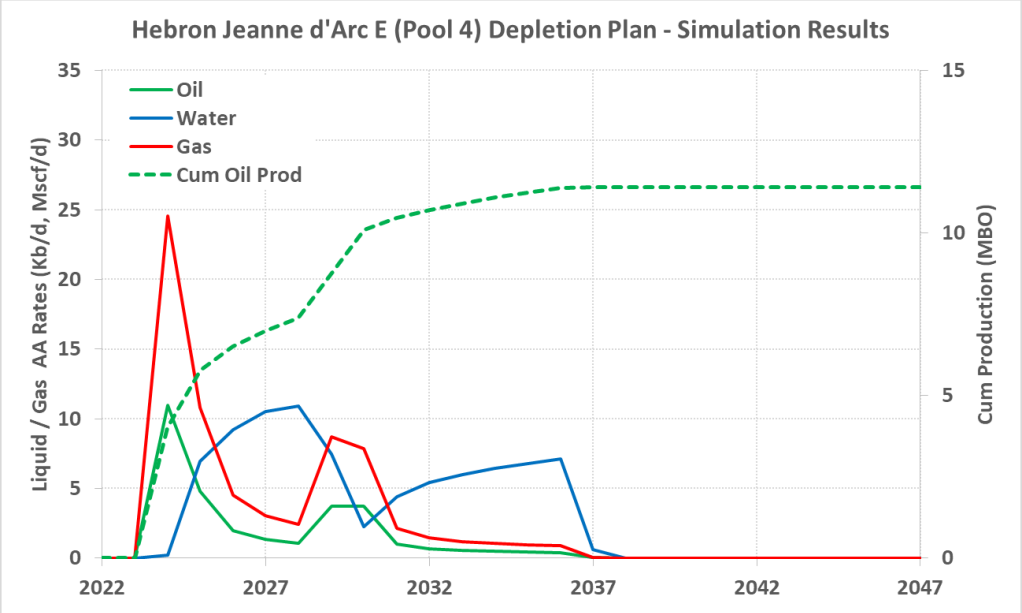


Figure 4-26: Pool 4E Sand Base Case Depletion Plan Simulation Results

An alternate depletion plan with primary recovery scheme was considered. Figure 4-27 is a graph comparing the results of a primary recovery (single producer) scheme and the base case depletion plan (one producer and one water injector). The simulation results from implementing a primary depletion scheme in the Jeanne d'Arc E Sand reservoir predict an oil recovery of 2.30 million barrels (0.4 Mm3) which is significantly lower than 11.4 million barrels (1.8 Mm3) from the base case depletion plan. The results show that providing pressure support maximizes resource recovery in the Jeanne d'Arc E Sand reservoir.

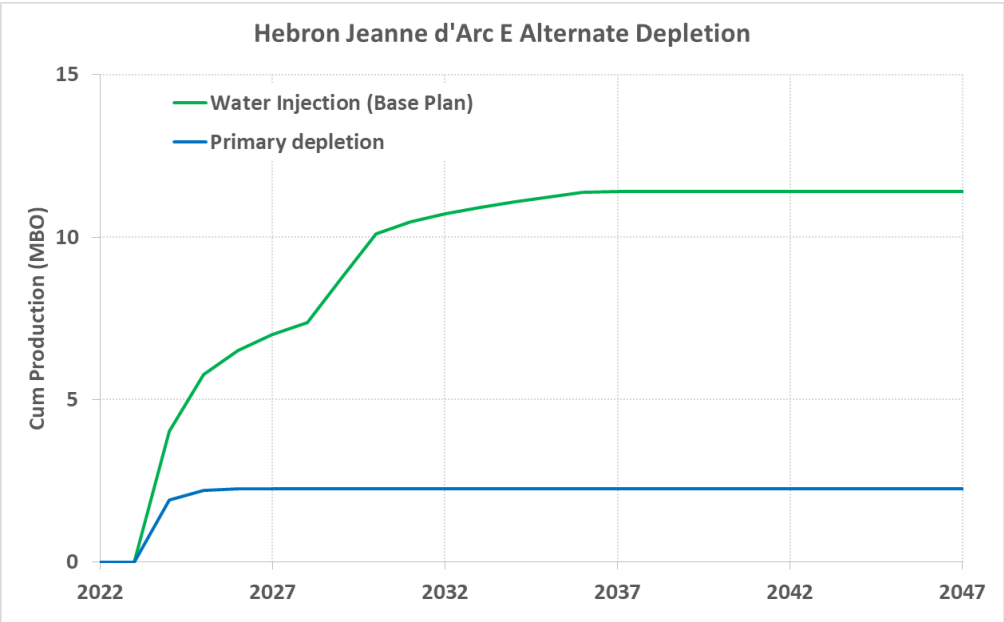


Figure 4-27: Pool 4E Sand Alternate Depletion Plan – Primary Depletion

During the detailed well planning phase, the possibility of drilling a single water injection well supporting multiple sands in the Jeanne d'Arc Formation will be investigated.

Gas injection and other gas related mechanisms of depletion including water-alternate-gas were not considered due to the higher subsurface pressure of the Jeanne d'Arc Formation and would require adding surface compression equipment. The Operator will continue to test the potential for the addition of other development strategies to optimize reservoir performance as new information becomes available.

Figure 4-28 shows the average reservoir pressure profile of the base case simulation through time.

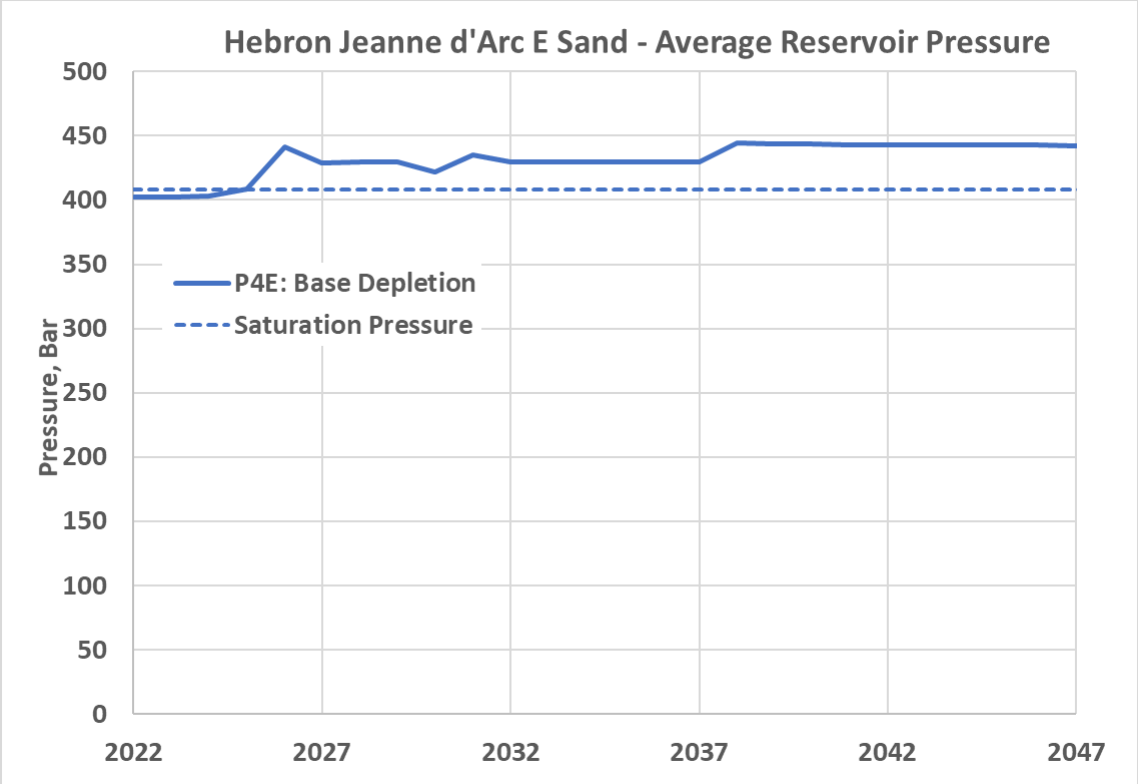


Figure 4-28: Pool 4E Sand average reservoir pressure through time for the base case development scenario.

4.4.4 Pool 4C Sand

Pool 4C Sand is estimated to recover 27.8 million barrels of oil (4.4 Mm3) in the base case depletion plan. The production profiles outlining the liquid and gas production derived from the base case depletion plan are shown in Figure 4-29. The production profiles are supported by simulation only, and do not include the impacts of facility design constraints and other operational downtime and turnarounds. The Jeanne d'Arc C Sand production profiles incorporating these assumptions are provided in Section 5.

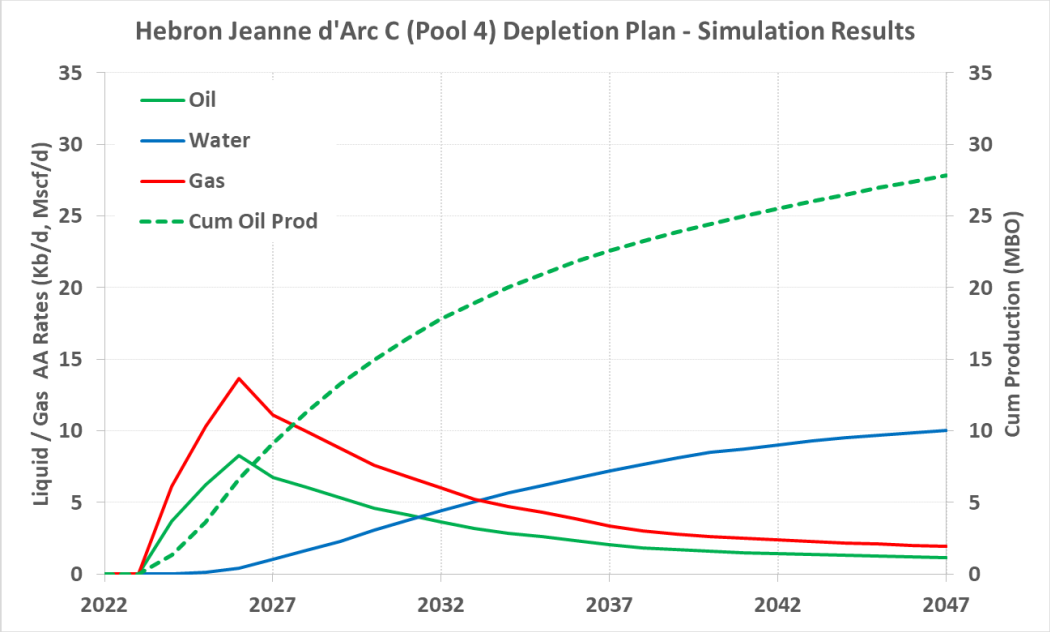


Figure 4-29: Pool 4C Sand Base Case Depletion Plan Simulation Results

The Pool 4C Sand base depletion plan involves maintaining reservoir pressure through water injection. Primary depletion was also considered. Figure 4-30 compares the results of a primary recovery scheme and the base case depletion plan. The simulation results from implementing a primary depletion scheme in the Jeanne d'Arc C Sand reservoir predict an oil recovery of about 9.0 million barrels (1.4 Mm3) which is lower than 28 million barrels (4.4 Mm3) predicted by the base case depletion plan. The oil recovery was relatively insensitive to the number of oil producers drilled, as can be seen from Figure 4.22 where the number of producers was increased from two to four without any significant incremental recovery. Based on these results, it is concluded that providing pressure support helps to maximize resource recovery in the Jeanne d'Arc C Sand reservoir.

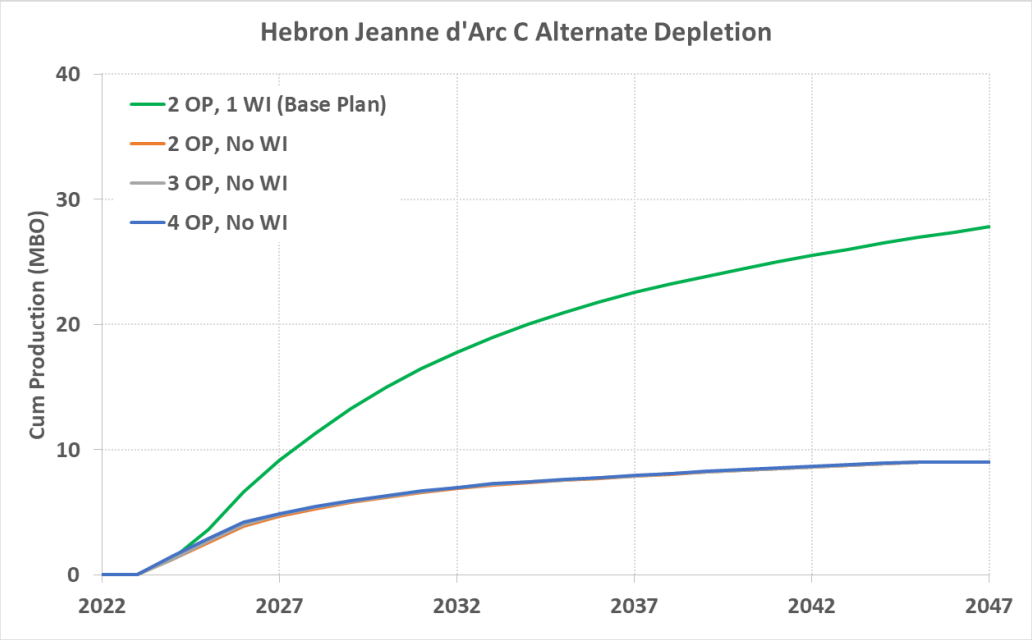


Figure 4-30: Pool 4C Sand Alternate Depletion Plan – Primary Depletion

During detailed well planning phase, the potential to drill a single water injector supporting multiple sands in the Jeanne d'Arc Formation will be investigated.

Gas injection and other gas related mechanisms of depletion including water-alternate-gas were not considered due to the relatively higher subsurface pressure of these resource which would require added surface compression equipment. The Operator will continue to test the potential for the addition of other development strategies to optimize reservoir performance as new information becomes available.

The average reservoir pressure profile as a function of time for the base case C Sand development scenario is provided in Figure 4-31.

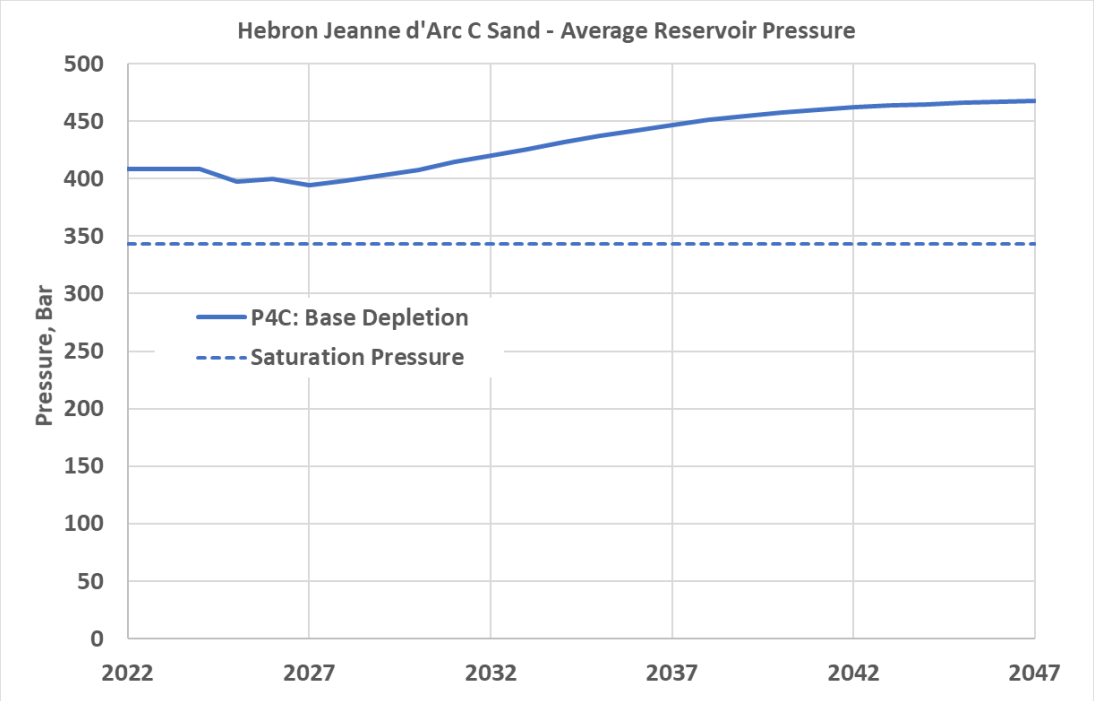


Figure 4-31: Pool 4C Sand average reservoir pressure through time for the base case development scenario

4.4.5 Pool 4B Sand

Pool 4B Sand estimated oil recovery after 23 years is 28.2 million barrels (4.5 Mm3) in the base case depletion plan. Figure 4-32 shows the oil recovery as well as liquid and gas production profiles derived from the base case depletion plan. The production profiles are based on a single development scenario supported by simulation. The production forecast is not based on a full-field integrated model and does not include the impacts of facility design constraints and other operational downtime and turnarounds. The Jeanne d'Arc B Sand reservoir production profiles incorporating these assumptions are provided in Section 5.

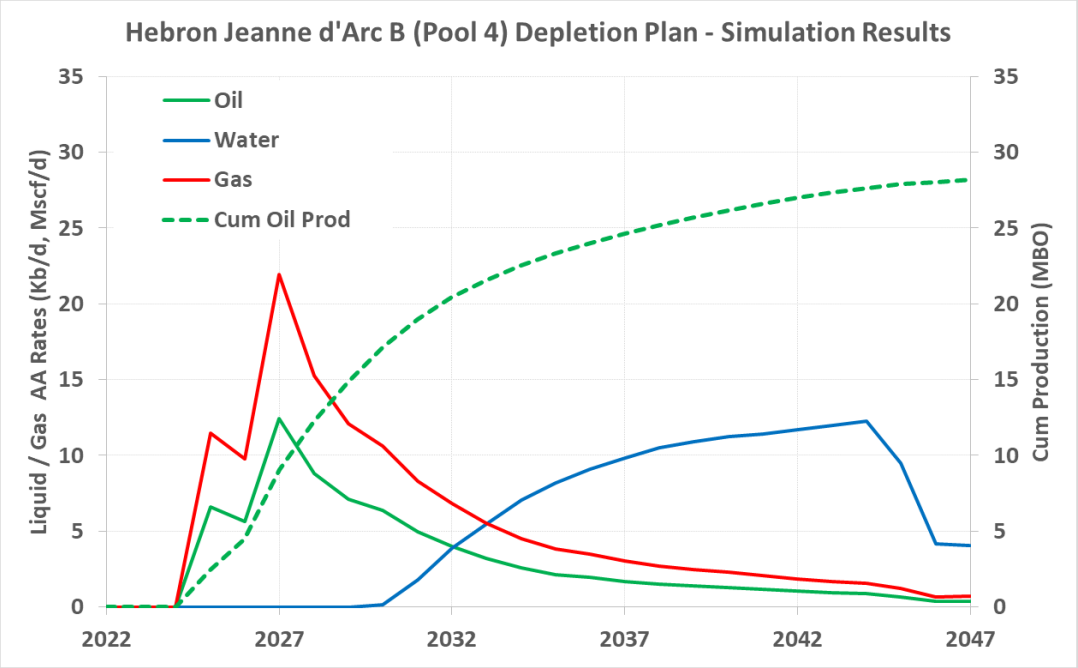


Figure 4-32: Pool 4B Sand Base Case Depletion Plan Simulation Results

Pressure maintenance through water injection is the main recovery mechanism in Pool 4B Sand. Other forms of depletion plans such as primary depletion were also considered. The simulation results from implementing a primary depletion scheme in the Jeanne d'Arc B Sand reservoir predict an oil recovery of 8.6 million barrels (1.4 Mm3). The oil recovery was insensitive to the number of oil producers drilled, as seen from Figure 4-33. Based on these results, providing pressure support helps to maximize resource recovery in the Jeanne d'Arc B Sand reservoir.

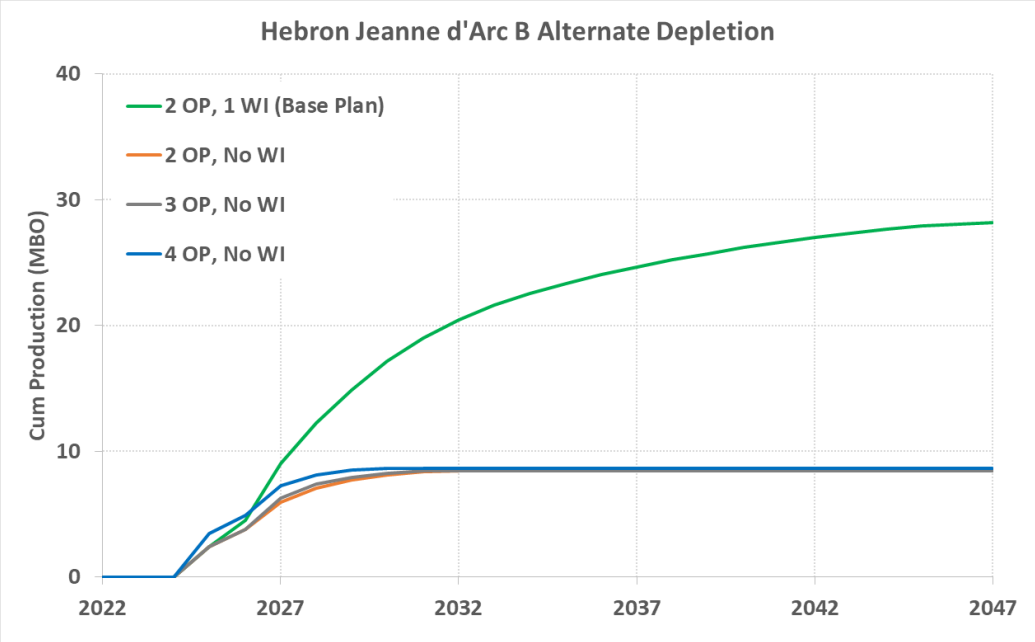


Figure 4-33: Pool 4B Sand Alternate Depletion Plan – Primary Depletion

During the well planning for shallower water injectors, the potential to include deepening to the B Sand reservoir will be investigated. Likewise, the potential to incorporate shallower Jeanne d'Arc sands in the B Sand reservoir injector will also be considered.

Gas injection and other gas related mechanisms of depletion including water-alternate-gas were not considered due to the relatively higher subsurface pressure of these resource which would require added surface compression equipment. The Operator will continue to test the potential for the addition of other development strategies to optimize reservoir performance as new information becomes available.

A profile of the average reservoir pressure as a function of time for the Pool 4B base case development scenario is shown in Figure 4-31.

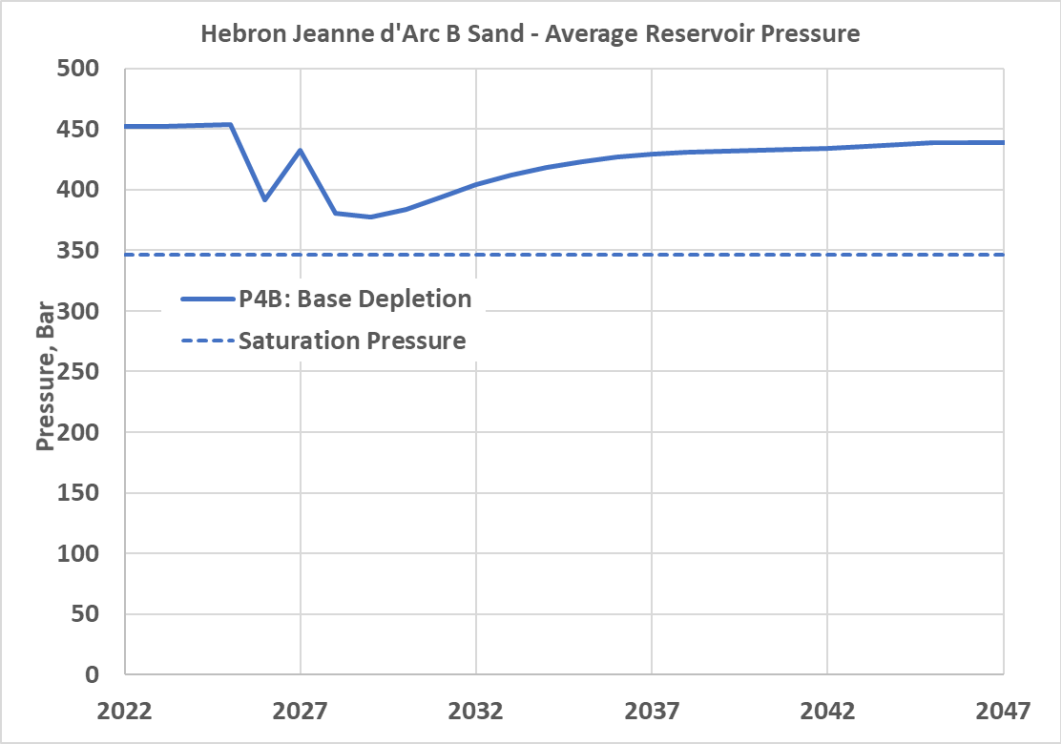


Figure 4-34: Pool 4B Sand average reservoir pressure through time for the base case reservoir scenario

4.5 Reservoir Management Plan

Consistent with the development of the Hebron Asset, the reservoir management plan for the JDA Sands considers maximizing the economic value of recoverable hydrocarbons through effective cross-functional and across asset interactions involving people, technology, and processes. The reservoir management plan will focus on the key reservoir management assumptions, knowledge, and learnings included in the depletion plan; assessment of data collected during surveillance activities; and how the knowledge, learnings and data will be utilized. The team's expertise, alignment, and overall understanding of the reservoir management process are key factors for the successful implementation of the reservoir management plan.

High-level JDA Sand reservoir management considerations include, but are not limited, to the following:

- Achieving rapid oil rate build-up: reflects the need to maximize oil production and will be addressed via the development drilling strategy that provides a balance between maximizing production and acquiring important reservoir and fluid data
- Increasing confidence in reservoir characterization: continuing to improve static and dynamic reservoir descriptions (e.g. structural and stratigraphic models, facies distributions, rock and fluid properties, etc.) via data collected during development drilling
- Well slot management: optimize well slot utilization to derive maximum value from available GBS well slots. Potential activities include slot reclamation, targeting multiple production or injection zones with single wellbores, etc.

- Producer well performance: attention to achieving and sustaining high completion flow efficiency and maintaining long-term effectiveness of sand control where necessary
- Injector well performance: consideration of the stratigraphic distribution of injected fluids, achieving and sustaining high completion flow efficiency, and monitoring the impact of reservoir cooling near the water injection sites
- Ensuring efficient utilization of produced gas: encompasses issues associated with providing gas-lift gas as well as gas consumed in operations. The objective is to utilize associated gas in the most efficient manner to benefit long-term oil recovery and fuel gas availability.
- Reservoir souring management: efficient monitoring and management of reservoir souring
- Fluid contact determination: continue to gather data to aid in refine fluid contact interpretations

4.5.1 Displacement Strategy

The proposed displacement strategy plan for JDA Sands is secondary recovery by water injection. Achieving this strategy includes good understanding of key reservoir metrics such as:

- Pressure maintenance and voidage balancing: timely monitoring of water injection rates to maintain pressure at optimal voidage replacement ratio to maximize oil recovery
- Flood conformance monitoring: managing the evolution of water cuts and / or GORs will be key to attaining high recovery of oil
- Connectivity and communication: reservoir connectivity and communication impacts, effectiveness of pressure maintenance, reservoir sweep and ultimate recovery; learnings from the production performance of each reservoir unit may result in upward or downward adjustments to the well count and / or resources
- Identifying bypassed oil potential: analytical and/or reservoir simulation methods and tools (including incorporating data gathered during asset development and production phases) to assist in identifying un-swept or poorly swept regions of individual reservoirs. Effective use of these tools can potentially lead to opportunities for future exploitation of such regions.

4.5.2 Data Acquisition

Data acquisition will follow the approved 2021 Hebron Field Data Acquisition Program (FDAP) and in accordance with the *CNLOPB Drilling and Production Guidelines (2017)* and the *Data Acquisition and Reporting Guidelines (September 2020)*.

Data acquisition will be a dynamic process, adapting to the operational environment and stage of Hebron development. Field data acquisition will be continuously re-assessed to ensure that key uncertainties are being addressed, to support decision making and that the value of the information.

In line with the 2021 Hebron FDAP, proposed Pool 4 data acquisition is focused on reducing reservoir uncertainties and enhancing resource recovery with emphasis on the following objectives:

- To reduce depth uncertainty
- To assess reservoir quality variability away from current well control
- To evaluate reservoir connectivity and/or reservoir compartmentalization

Data acquisition is subject to change as drilling progresses and formation evaluation objectives evolve.

4.5.3 Reservoir Surveillance

Reservoir surveillance is a cornerstone of effective reservoir management and involves the collection, integration, and comprehensive analysis of reservoir and well performance information. Appropriate surveillance will help maintain the integrity of production and injection wells, optimize the performance of developed areas, and identify economically viable opportunities for future development. The surveillance plan provides a systematic and objective-based structure to focus these efforts to maximize the value of the asset.

As per the Hebron Reservoir Surveillance Plan, Pool 4 reservoir surveillance plan will be designed with the following objectives:

- To collect necessary data required to optimize base production, support planned development and maximize long-term resource recovery
- To allow flexibility for changes and learnings

The following data sources are expected to provide essential information for monitoring production performance and for evaluating effectiveness of the planned recovery processes:

- Permanent downhole pressure gauges as needed, providing frequent data measurements for adequate reservoir pressure determination
- Periodic short-term production tests on each producing well through a test separator to provide key data regarding produced volumes and produced-fluid ratios
- Periodic fluid samples obtained near the wellhead to monitor water cut, water salinity and produced oil density
- Production / Injection logs as required to help diagnose significant and / or unanticipated changes in well performance and zonal contributions in the case of commingled wells
- Periodic well shut ins to measure reservoir pressure and fulfil the requirements of the annual Pool pressure survey

4.5.4 Workovers

A workover is defined as the process of performing major maintenance or remedial treatments on an oil, gas or water well.

Post drill workovers to improve recovery using non-rig workovers such as wireline and coil tubing can include:

- Recompletion (reperforation, perforating new zones)
- Profile control (isolation plugs, straddle packers)
- Surveillance logs (injection production, saturation)

Rig workovers are undertaken for more involved operations, such as replacement or repair of defective tubing equipment, completion of a shallower zone, and gas-lift retrofitting.

Authorization for workovers is managed through the Approval for Well Operation (AWO) process, which requires C-NLOPB approval prior to completing, reclaiming, or abandoning intervals.

5 Integrated Project Flowstreams

5.1 Assumptions and Methodology

The integrated flowstreams include volumes from Pools within the development plan. Potential future opportunities from Pools outside of the development plan are not included. 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 5-1 shows the facility capacities used for the integrated flowstreams.

Table 5-1 Hebron Facility Capacities

	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

Independent geologic models exist for Pool 1, Pool 2, Pool 5, Pool 4 H Sand, and Pool 4 JDA.

- The main geologic model for Pool 1 is described in the 2011 Hebron Development Plan and continues to be in use. Annual updates have been provided in the annual production reports documenting history match edits required to maintain alignment with dynamic performance.
- The Pool 2 model was built in 2020 to support the Pool 2 gas storage assessment. This model was based on updated structure maps derived from the seismic interpretation of the 2015 seismic depth cube and tied to the L-93 06 gas injector and B-75 exploration well.
- The Pool 5 geologic model was updated in 2022 to align with recent drill well results. Early dynamic data from the first development well, L-93 29z, was used to guide the property population methodology.
- The Pool 4H model was built in 2021 and incorporated data acquired through the L-93 22 well. The second development well, L-93 30z, was drilled in mid-2022 but dynamic learnings from this well have not yet been incorporated.
- The Pool 4 JDA model was built in 2022 and includes all of the Pool 4 sands. The model was described in detail in Section 3.7 and was used as the basis for the flowstreams for sands G through B.

5.2 Development Plans by Pool

5.2.1 Ben Nevis Pool 1

The Pool 1 Ben Nevis Formation is the main reservoir developed since the start-up of the Hebron facility in 2017. It is comprised of the Hebron horst block (also referred to as D-94 block) and the I-13 fault block. Development of the D-94 and I-13 fault blocks are included in the current development plan. A third fault block, Southwest Graben (SWG) was potentially an extension of the Pool 1 oil accumulation but L-93 31, drilled in 2021, determined a shallower oil water contact in poor reservoir quality. The SWG is not expected to be economic based on the current assessment and no volumes are included for it within the integrated flowstream. A structure map of the top of the reservoir is shown in Figure 5-1

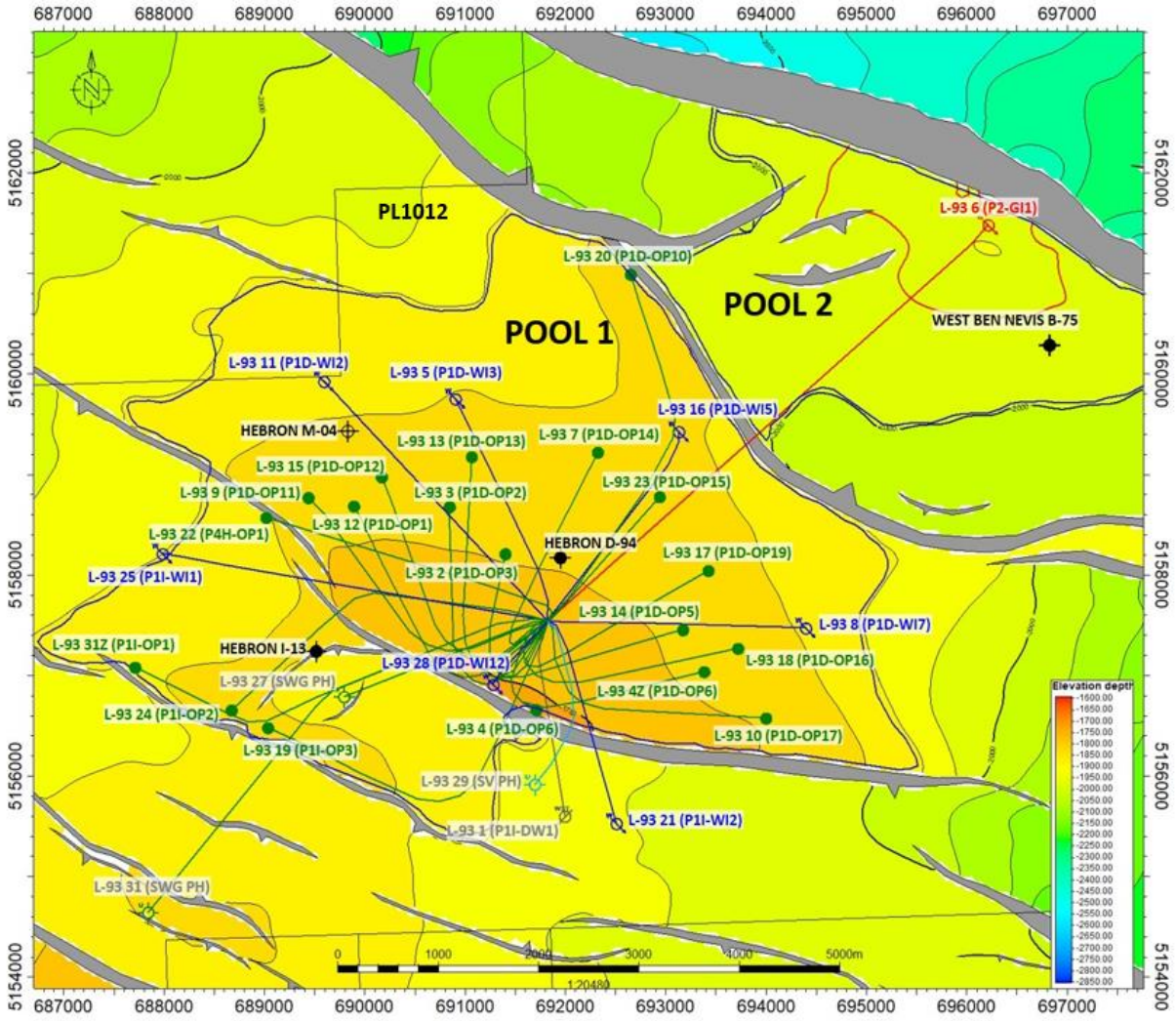


Figure 5-1 Hebron Field Top Ben Nevis Structure Map (m TVDss)

Exploration and production drilling in Pool 1 has encountered a high quality sand with good lateral connectivity and indications of vertical baffling. Pre-production geologic interpretation of environment of deposition and reservoir quality has proven to be robust and very little modification of the interpretation has been required.

Upon start-up of the Hebron field in 2017, the plan for both the D-94 and I-13 blocks consisted of horizontal oil producers spanning multiple zones with down-dip water injection for pressure support. With development learnings there have been some minor revisions to the development plan including,

- I-13 injection wells were revised from water injection only to water-alternating-gas wells. This was a result of the overall Hebron gas management strategy once it was realized the storage capacity in Pool 2 was lower than initially expected. The I-13 WAG wells were drilled in 2020/2021 and have been performing in line with expectations.
- The crest of the D-94 block was previously expected to be developed with two oil producers. The pressure support in the Upper zones was less than originally expected due to vertical baffling at the Zone 4. As a result of technical work investigating options to improve pressure support to the Upper wells, the crest was developed with a single injection well. This option is expected to result in improved rate and recovery. The crestal injector, L-93 28, was drilled in 2021 and is currently injecting water. The well was designed as 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.
- From a well count perspective, the optimization of the injection strategy resulted in an overall decrease in well count for the Pool 1 from 24 in the original development plan to the current well count of 19 wells. This is in part due to a reduced number of flank injectors required due to the better than expected injectivity observed in the water injection wells.

The initial development drilling planned for Pool 1 is now complete. There are no additional drill wells assumed in the integrated forecast. It is expected that the Lower wells will have a shorter well life due to higher water cut, with well reclaims expected in the ~2028 timeframe. It is expected that the majority of the Upper wells will remain for the life of the field. If the platform becomes slot limited, it may be possible to reclaim a number of slots in use by Upper wells through the use of multi-laterals. A placeholder Pool 1 re-drill has been included within the integrated drill schedule but there are no volumes associated with this well. Additional drill well opportunities in Pool 1 will continue to be evaluated based on continued static and dynamic data collection.

5.2.2 Ben Nevis Pool 2

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 in association with oil produced. The current subsurface license was issued and effective for a term of 3 years commencing October 1, 2020.

The reservoir sits within a tilted fault block trap located to the northeast of Pool 1. As a result of syntectonic deposition, the Ben Nevis Formation thickens across the fault from Pool 1 into Pool 2. The hydrocarbon-bearing interval in Pool 2 is downthrown and offset from Pool 1, resulting in different fluid contacts between the two blocks. Overall reservoir quality degrades from Pool 1 to Pool 2, due to a transition to more distal shoreface environment of deposition (EOD) and facies. The increased content of finer grained material results in lower porosity, permeability, and net-to-gross than observed in Pool 1.

The L-93 06 well was drilled in mid-2018 at the crest of the Pool 2 structure and encountered reservoir quality consistent with pre-drill EOD and reservoir quality assumptions. An assessment of the first 15 months of injection indicated the storage capacity in Pool 2 was less than originally expected and

insufficient to meet the full Hebron field requirements. This led to the update of the gas management strategy and the incorporation of WAG wells in the I-13 block.

Pool 2 remains an approved gas storage option and performance continues to be monitored. In the future, as the oil reservoirs decline, it is expected that additional gas production will be required to meet operational demand. The current field integrated flowstream assumes that L-93 06 will be converted from an injector to a producer to meet operational gas demand. Prior to any production from the Pool 2 a development plan amendment will be submitted for the Pool 2.

5.2.3 Jeanne d'Arc Pool 4

In the Hebron area, the Jeanne d'Arc Formation is a thick succession (up to 650m) comprised of 7 interpreted depositional sequences, from oldest to youngest: B, C, D, E, F, G and H sands. The Jeanne d'Arc Formation is interpreted to have multiple independent oil columns as most of the reservoir sands are vertically separated by intervening shales. This interpretation is supported by pressure observations.

Oil has been encountered (drilled/tested) in the B, C, D, E, F, G and H sands at Hebron. B and H sands were incorporated into the original Development Plan as, at that time, those were the only sands that had interpreted sufficient economic oil accumulations. The proposed amendment to the Development Plan includes the potential to development any of the sands within the Pool 4. Recent wells have encountered oil filled sands in good quality reservoir with sufficient net thickness to be prospective including within the E/D Sand and the C Sand. The base development plan for the Pool 4 continues to rely primarily on horizontal wells targeting a single sand. Additional potential has also been acknowledged to produce from the smaller sands, such as G or F, using commingled production. The integrated schedule for 2022 includes a total of 10 producers and 6 water injectors for a total well count of 16 (including wells drilled to date). The original development plan for the Jeanne d'Arc included 6 wells, 4 wells in H Sand and 2 wells in B sand. It was acknowledged at the time that the total number of wells may change due to a number of factors.

5.2.4 Hibernia Pool 5

The Early Cretaceous Hibernia Formation conformably overlies the Fortune Bay shales. It is commonly divided into an Upper and Lower member with the oil at Hebron Asset found in the Upper Hibernia member. The Hibernia reservoir interval consists of interbedded sandstones and shales and is interpreted to have been deposited in a clastic, shallow marine, wave dominated shoreface environment. The lithofacies span offshore shales to fluvial sandstones but the majority of the preserved rocks at Hebron are deposited in the middle to lower shoreface. Many of the sandstones are cemented with calcite.

Based on the exploration wells, I-13 and M-04, the free water level for Pool 5 was interpreted to be -2987m TVDss. Uncertainty existed with this value due to the lack of data to define the oil gradient and the contact not being observed on logs. Pressure and log data acquired on L-93 22 and L-93 29 reduced the uncertainty and established a free water level of -2966m TVDss. Due to uncertainty in the velocity model, it was not anticipated that Zone 1-1 would be sufficiently above the FWL to be economic. L-93 29 encountered a shallower top Zone 1-1. Even though the FWL was shallower than anticipated, the change in structure resulted in a developable volume within the oil leg.

The base development plan for the Pool 5 included three horizontal producers supported by a single deviated water injector. The first oil producer and water injector for Pool 5 were drilled in 2022. The

combined static and dynamic learnings within the Pool 5 have indicated potential for more drill well opportunities than originally envisaged. There is substantial oil in place within the Pool 5 and it is expected that additional producers will be economically justified. The integrated schedule for 2022 includes a total of 7 producers and 2 water injectors, representing an increase in well count from 4 to 9. There is potential to drill some of the future producers as multi-laterals as the locations are well suited for this technology. The current model predicts a wide range of potential from the additional drill wells, primarily based on the stochastic nature of the model. The well flowstreams used for the future wells in the integrated flowstream have been normalized to represent the average expectation.

5.3 Integrated Well Count and Sequence

The integrated drill schedule provided herein is consistent with the current production forecast for the Hebron project. The long term drill schedule is an evergreen plan that changes as additional information is gathered or technical work is completed. The seriatim of wells takes into consideration the projected production uplift, the timing of data acquisition, the availability of mechanical equipment, and the required planning time. Figure 5-2 shows the assumed drill schedule for the integrated flowstream. The platform is currently not actively drilling as required rig recertification activities are underway. The length of time for this period remains under evaluation. For the purpose of the integrated flowstream it is assumed that drilling will recommence Sept 2023.

The drilling campaign will include an optimized seriatim of opportunities, which are subject to change as technical work is progressed. As a result of additional drill wells in Pool 4 and 5, as well as a number of potential future appraisal opportunities, the integrated drill schedule extends through 2029.

Table 5-2 shows the well count by pool for the Hebron development scope. There have been some minor changes to the well counts since the last summary provided in the 2021 Annual Production Report. Within the Pool 5 the well count has increased from 4 to 9 based on the static and dynamic learnings. There is incremental recovery associated with the additional wells which has been reflected in the flowstreams. Within the Pool 4 the total well count has increased from 9 to 16 primarily associated with development wells targeting the C and the E/D sands. A summary of the Pool 4 well count by sand is shown in Table 5-3.

A total well count of 51 (including 1 CRI) is projected, which is within the Hebron platform design of 52 well slots. Additional development potential is under evaluation, including future appraisal opportunities which would target areas of undiscovered or uncertain potential. In a success case, additional development could be possible, so strategic use of well slots is considered with every drill well opportunity. Existing technologies such as slot reclaims, and multi-lateral completions may be used to optimize future slot utility while maximizing targets.

Table 5-2 Hebron Project Well Count By Pool

Pool	Reservoir / Compartment	Production Wells	Injection Wells	Total
Pool 1	Hebron Ben Nevis, D-94	14	5	19
	Hebron Ben Nevis, I-13	3	2	5
	Pool 1 Total	**17**	**7**	**24**
Pool 5	Hebron Hibernia	7	2	9
Pool 4	Hebron JdA	10	6	16
Pool 2	West Ben Nevis, Ben Nevis	0	1*	1*
Total		**34**	**16**	**50**

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

Table 5-3 Hebron Jeanne d'Arc Well Count by Sand

Pool	Reservoir / Compartment	Production Wells	Injection Wells	Total
Pool 4	H Sand	3	3	6
Pool 4	E/D Sand	1	1	2
Pool 4	C Sand	2	1	3
Pool 4	B Sand	2	1	3
Pool 4	Commingled*	2		2
P4 Total		**10**	**6**	**16**

*Commingled includes L-93 22 and 1 future commingled well

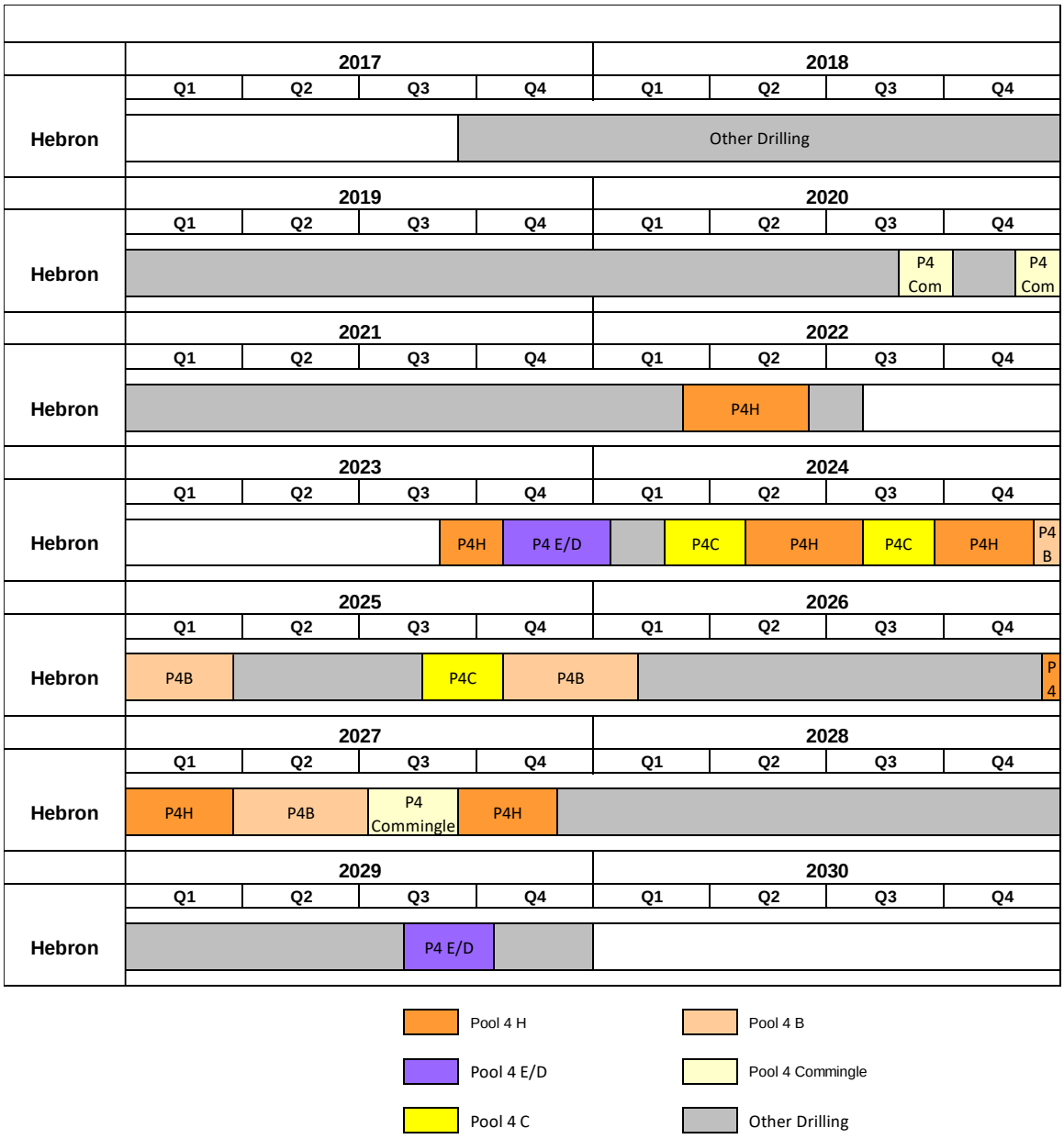


Figure 5-2 2022 Integrated Drill Schedule

5.4 Production and Injection Flowstreams

Forecasts are presented 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 which includes a multi-disciplinary assessment of the current performance.

A summary of the EUR by Pool from the integrated flowstream is shown in Table 5-4. A comparison is provided to the EUR in the original project Development Plan and to the last updated provided in the 2021 Annual Production Report.

Table 5-4 Hebron Integrated Flowstream EUR Summary by Pool

EUR	Orig Dev Plan		2021 APR		2022 JdA DPA	
	MB	Mm3	MB	Mm3	MB	Mm3
Pool 1	563	89.5	616	97.9	616.6	98.0
Pool 5	15	2.4	41	6.5	65.7	10.5
Pool 4	87	13.8	79	12.5	122.0	19.4
TOTAL	**665.0**	**105.7**	**735.9**	**117.0**	**804.4**	**127.9**

Figure 5-3 and Table 5-5 break out the volumes associated with the sands covered under the JDA Development Plan Amendment (G, F, E/D, and C Sands).

Table 5-6 through Table 5-10 and Figure 5-4 through Figure 5-9 provide production and injection forecasts on an annual basis for the total Hebron Project development scope as well as the individual pools.

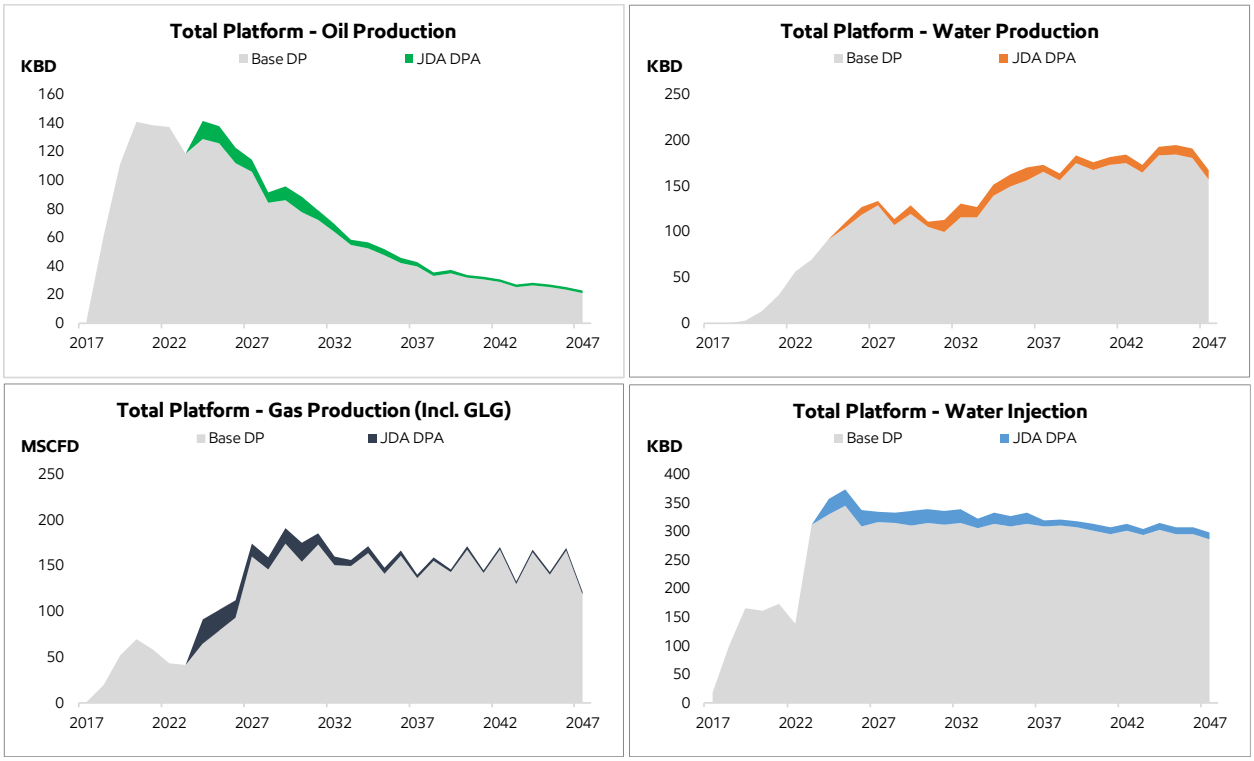


Figure 5-3 Production and Injection Flowstreams - Increment Associated with JDA DPA

Table 5-5 Production and Injection Volumes for JDA DPA Sands (G, F, E/D, and C)

Year	Oil Production		Gas Production		Water Production		Water Injection	
	kbd	km3/d	Mscfd	MSm3/d	kbd	km3/d	kbd	km3/d
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	1.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	13.2	2.1	27.9	0.8	0.0	0.0	27.2	4.3
2025	11.1	1.8	21.7	0.6	5.6	0.9	27.6	4.4
2026	10.7	1.7	18.8	0.5	7.9	1.2	28.1	4.5
2027	8.1	1.3	13.8	0.4	4.2	0.7	18.0	2.9
2028	7.4	1.2	12.8	0.4	6.2	1.0	17.9	2.9
2029	9.3	1.5	17.4	0.5	8.9	1.4	25.3	4.0
2030	10.5	1.7	20.4	0.6	5.5	0.9	24.7	3.9
2031	6.4	1.0	11.6	0.3	12.6	2.0	23.5	3.7
2032	5.5	0.9	10.0	0.3	15.2	2.4	24.5	3.9
2033	3.7	0.6	6.3	0.2	6.6	1.0	12.3	2.0
2034	3.5	0.6	5.9	0.2	5.8	0.9	11.1	1.8
2035	3.2	0.5	5.4	0.2	6.3	1.0	11.2	1.8
2036	2.9	0.5	4.9	0.1	6.9	1.1	11.2	1.8
2037	2.6	0.4	4.3	0.1	7.4	1.2	11.2	1.8
2038	2.2	0.3	3.6	0.1	7.2	1.1	10.3	1.6
2039	2.2	0.3	3.7	0.1	8.3	1.3	11.4	1.8
2040	2.0	0.3	3.5	0.1	8.7	1.4	11.6	1.8
2041	2.0	0.3	3.3	0.1	9.0	1.4	11.7	1.9
2042	1.9	0.3	3.1	0.1	9.3	1.5	11.9	1.9
2043	1.6	0.3	2.8	0.1	8.7	1.4	11.0	1.7
2044	1.7	0.3	2.9	0.1	9.7	1.5	12.1	1.9
2045	1.6	0.3	2.8	0.1	9.9	1.6	12.2	1.9
2046	1.6	0.3	2.7	0.1	10.1	1.6	12.3	2.0
2047	1.4	0.2	2.4	0.1	9.4	1.5	11.4	1.8
Cum Oil (MB / Mm3)	**43**	**6.8**	**77**	**2.2**	**69**	**11.0**	**142**	**22.6**

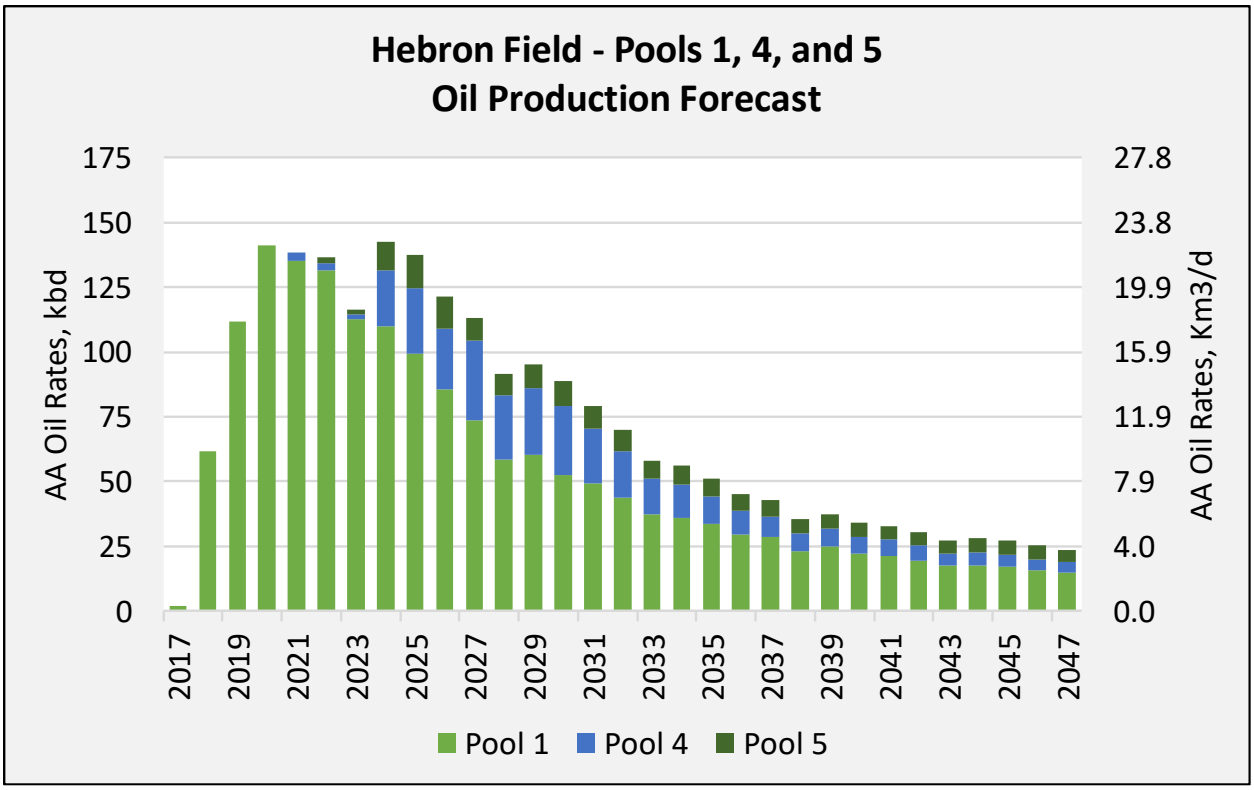


Figure 5-4 Hebron Field (Pool 1, 4, and 5) Oil Production Forecast

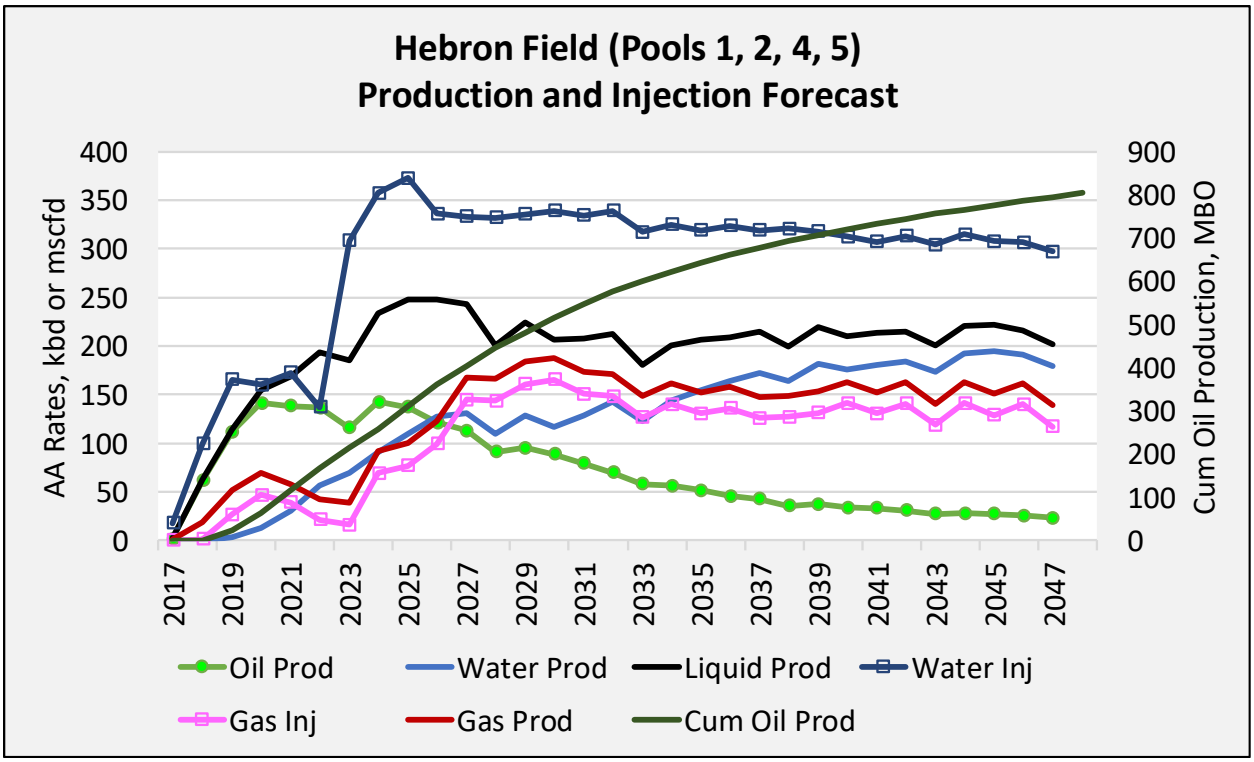


Figure 5-5 Hebron Field Production and Injection Forecast

Table 5-6 Hebron Field Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection		Gas Injection	
	kbd	km3/d	Mscfd	MSm3/d	kbd	km3/d	kbd	km3/d	Mscfd	MSm3/d
2017	2.0	0.3	0.6	0.0	0.0	0.0	18.0	2.9	0.0	0.0
2018	61.7	9.8	19.0	0.5	0.2	0.0	99.5	15.8	1.1	0.0
2019	111.6	17.7	51.3	1.4	3.0	0.5	165.6	26.3	26.5	0.7
2020	141.2	22.4	69.0	1.9	13.2	2.1	160.2	25.5	46.7	1.3
2021	138.5	22.0	57.8	1.6	30.6	4.9	172.5	27.4	39.4	1.1
2022	136.5	21.7	42.4	1.2	56.6	9.0	137.3	21.8	21.4	0.6
2023	116.2	18.5	38.9	1.1	69.5	11.0	308.7	49.1	16.0	0.5
2024	142.4	22.6	92.4	2.6	91.3	14.5	357.3	56.8	69.5	2.0
2025	137.4	21.8	100.1	2.8	110.2	17.5	372.8	59.3	77.2	2.2
2026	121.4	19.3	122.5	3.5	127.2	20.2	336.0	53.4	99.6	2.8
2027	113.1	18.0	167.7	4.7	130.4	20.7	333.3	53.0	144.8	4.1
2028	91.3	14.5	166.7	4.7	109.8	17.4	332.2	52.8	143.8	4.1
2029	95.4	15.2	183.7	5.2	128.8	20.5	335.9	53.4	160.8	4.5
2030	88.8	14.1	188.2	5.3	117.3	18.6	339.1	53.9	165.4	4.7
2031	79.2	12.6	173.5	4.9	129.1	20.5	334.7	53.2	150.6	4.2
2032	70.1	11.1	171.4	4.8	142.3	22.6	339.1	53.9	148.6	4.2
2033	58.1	9.2	148.1	4.2	123.0	19.6	317.6	50.5	126.4	3.6
2034	56.0	8.9	161.7	4.6	144.5	23.0	324.9	51.7	140.0	3.9
2035	51.4	8.2	152.5	4.3	154.8	24.6	319.2	50.8	130.8	3.7
2036	45.4	7.2	157.6	4.4	163.6	26.0	323.9	51.5	135.9	3.8
2037	42.8	6.8	147.9	4.2	172.1	27.4	319.2	50.8	126.1	3.6
2038	35.5	5.6	148.9	4.2	163.8	26.0	320.9	51.0	127.1	3.6
2039	37.4	5.9	153.0	4.3	182.3	29.0	318.0	50.6	131.2	3.7
2040	33.9	5.4	163.0	4.6	176.4	28.0	312.6	49.7	141.2	4.0
2041	32.9	5.2	152.6	4.3	181.1	28.8	307.2	48.8	130.9	3.7
2042	30.7	4.9	162.6	4.6	184.6	29.4	313.3	49.8	140.9	4.0
2043	27.4	4.4	140.7	4.0	173.1	27.5	304.2	48.4	119.0	3.4
2044	28.2	4.5	163.0	4.6	192.7	30.6	315.3	50.1	141.3	4.0
2045	27.3	4.3	150.7	4.2	194.7	31.0	307.7	48.9	129.0	3.6
2046	25.2	4.0	161.6	4.6	191.3	30.4	306.8	48.8	139.9	3.9
2047	23.4	3.7	139.1	3.9	179.1	28.5	297.6	47.3	117.4	3.3
Cum Oil (MB / Mm3)	**804.4**	**127.9**	**1442.0**	**40.6**	**1401.2**	**222.8**	**3232.7**	**514.0**	**1201.1**	**33.8**

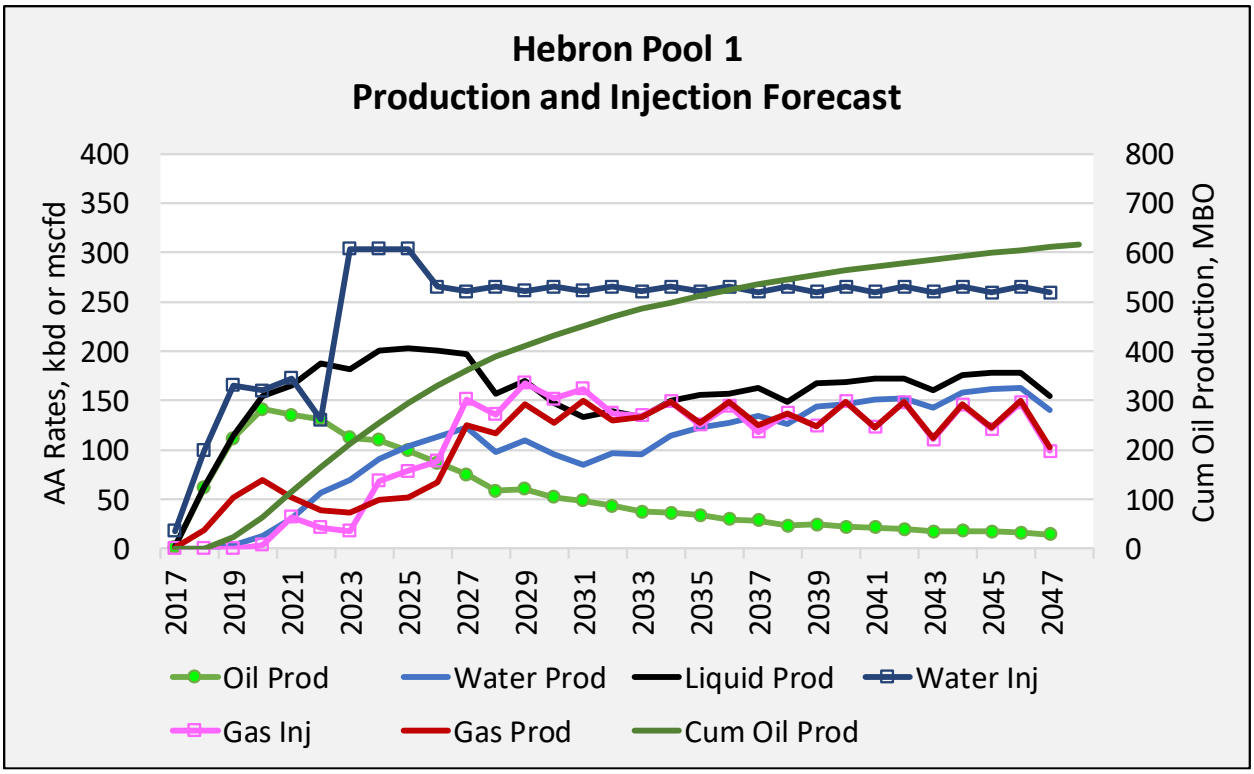


Figure 5-6 Pool 1 Production and Injection Forecast

Table 5-7 Pool 1 Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection		Gas Injection	
	kbd	km3/d	Mscfd	MSm3/d	kbd	km3/d	kbd	km3/d	Mscfd	MSm3/d
2017	2.0	0.3	0.6	0.0	0.0	0.0	18.0	2.9	0.0	0.0
2018	61.7	9.8	19.0	0.5	0.2	0.0	99.5	15.8	0.0	0.0
2019	111.6	17.7	51.3	1.4	3.0	0.5	165.6	26.3	0.0	0.0
2020	141.2	22.4	69.0	1.9	13.2	2.1	160.2	25.5	3.7	0.1
2021	135.2	21.5	51.7	1.5	30.6	4.9	172.5	27.4	32.0	0.9
2022	131.5	20.9	38.6	1.1	56.6	9.0	130.7	20.8	21.2	0.6
2023	112.6	17.9	36.2	1.0	69.5	11.0	304.0	48.3	16.0	0.5
2024	109.9	17.5	49.5	1.4	91.3	14.5	304.0	48.3	69.5	2.0
2025	99.3	15.8	51.3	1.4	103.5	16.5	304.0	48.3	77.2	2.2
2026	85.4	13.6	78.4	2.2	114.5	18.2	265.7	42.2	99.6	2.8
2027	73.8	11.7	118.9	3.4	120.1	19.1	261.0	41.5	144.8	4.1
2028	58.4	9.3	125.0	3.5	94.4	15.0	265.5	42.2	143.8	4.1
2029	60.2	9.6	138.9	3.9	109.8	17.5	261.4	41.6	160.8	4.5
2030	52.5	8.3	141.3	4.0	101.1	16.1	265.2	42.2	165.4	4.7
2031	49.2	7.8	138.5	3.9	101.1	16.1	261.1	41.5	150.6	4.2
2032	43.7	6.9	141.3	4.0	108.1	17.2	265.3	42.2	148.6	4.2
2033	37.5	6.0	125.7	3.5	96.5	15.3	260.7	41.4	126.4	3.6
2034	36.0	5.7	140.4	4.0	114.0	18.1	265.5	42.2	140.0	3.9
2035	33.7	5.4	133.7	3.8	121.6	19.3	260.5	41.4	130.8	3.7
2036	29.8	4.7	140.7	4.0	128.1	20.4	265.6	42.2	135.9	3.8
2037	28.6	4.5	132.6	3.7	133.7	21.3	260.3	41.4	126.1	3.6
2038	23.3	3.7	127.1	3.6	126.2	20.1	265.7	42.2	127.1	3.6
2039	24.8	3.9	131.2	3.7	142.7	22.7	260.2	41.4	131.2	3.7
2040	22.2	3.5	141.2	4.0	146.3	23.3	265.7	42.2	141.2	4.0
2041	21.5	3.4	130.9	3.7	150.2	23.9	260.0	41.3	130.9	3.7
2042	19.6	3.1	141.1	4.0	152.8	24.3	265.7	42.2	140.9	4.0
2043	17.6	2.8	120.5	3.4	142.8	22.7	259.9	41.3	119.0	3.4
2044	17.6	2.8	142.2	4.0	158.0	25.1	265.6	42.2	141.3	4.0
2045	17.2	2.7	130.5	3.7	161.0	25.6	259.7	41.3	129.0	3.6
2046	15.9	2.5	142.4	4.0	163.1	25.9	265.6	42.2	139.9	3.9
2047	15.0	2.4	120.7	3.4	152.8	24.3	259.6	41.3	117.4	3.3
Cum Oil (MB / Mm3)	**616.6**	**98.0**	**1187**	**33.5**	**1171.2**	**186.2**	**2719**	**432.2**	**1173**	**33.0**

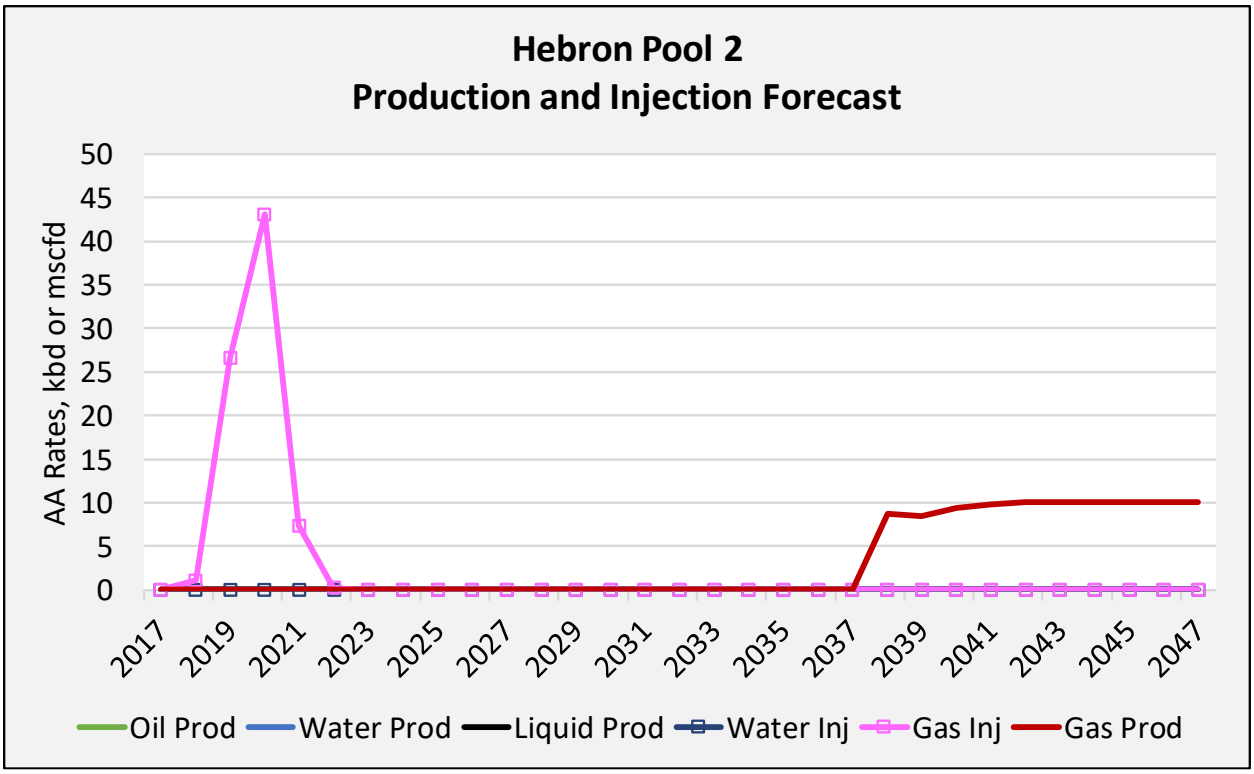


Figure 5-7 Pool 2 Production and Injection Forecast

Table 5-8 Pool 2 Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Gas Injection	
	kbd	km3/d	Mscfd	MSm3/d	kbd	km3/d	Mscfd	MSm3/d
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	1.1	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	26.5	0.7
2020	0.0	0.0	0.0	0.0	0.0	0.0	43.0	1.2
2021	0.0	0.0	0.0	0.0	0.0	0.0	7.4	0.2
2022	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0
2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2025	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2026	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2027	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2028	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2029	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2030	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2031	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2032	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2033	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2034	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2035	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2036	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	0.0	0.0	8.8	0.2	0.0	0.0	0.0	0.0
2039	0.0	0.0	8.4	0.2	0.0	0.0	0.0	0.0
2040	0.0	0.0	9.4	0.3	0.0	0.0	0.0	0.0
2041	0.0	0.0	9.8	0.3	0.0	0.0	0.0	0.0
2042	0.0	0.0	10.0	0.3	0.0	0.0	0.0	0.0
2043	0.0	0.0	10.0	0.3	0.0	0.0	0.0	0.0
2044	0.0	0.0	10.0	0.3	0.0	0.0	0.0	0.0
2045	0.0	0.0	10.0	0.3	0.0	0.0	0.0	0.0
2046	0.0	0.0	10.0	0.3	0.0	0.0	0.0	0.0
2047	0.0	0.0	10.0	0.3	0.0	0.0	0.0	0.0
Cum Oil (MB / Mm3)	**0.0**	**0.0**	**35.2**	**1.0**	**0.0**	**0.0**	**28.6**	**0.8**

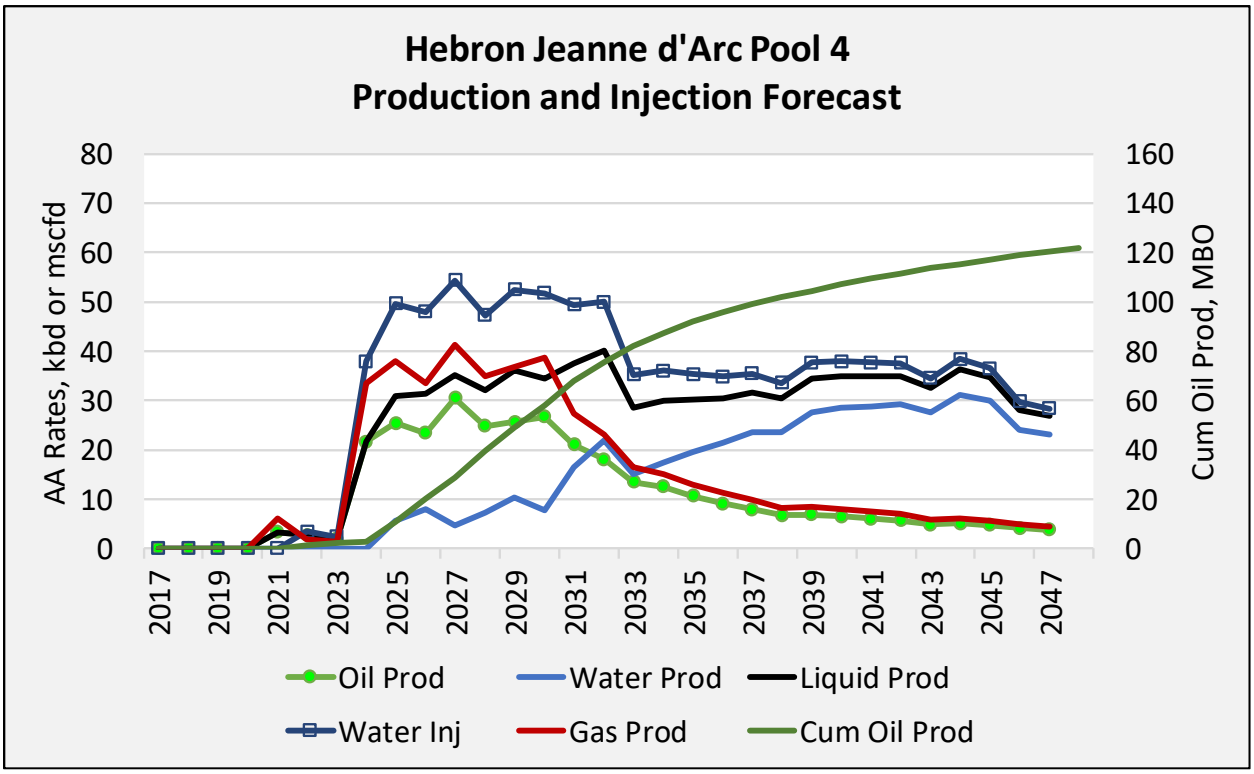


Figure 5-8: Hebron Pool 4 Production and Injection Forecast

Table 5-9 Hebron Pool 4 Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection	
	kbd	km3/d	Mscfd	MSm3/d	kbd	km3/d	kbd	km3/d
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	3.4	0.5	6.1	0.2	0.0	0.0	0.0	0.0
2022	2.8	0.4	1.9	0.1	0.0	0.0	3.5	0.6
2023	1.9	0.3	1.3	0.0	0.0	0.0	2.4	0.4
2024	21.6	3.4	33.6	0.9	0.0	0.0	37.9	6.0
2025	25.4	4.0	38.0	1.1	5.6	0.9	49.7	7.9
2026	23.4	3.7	33.5	0.9	7.9	1.3	48.0	7.6
2027	30.6	4.9	41.3	1.2	4.7	0.8	54.4	8.6
2028	24.9	4.0	34.8	1.0	7.3	1.2	47.2	7.5
2029	25.7	4.1	36.8	1.0	10.5	1.7	52.5	8.3
2030	26.7	4.2	38.8	1.1	7.7	1.2	51.8	8.2
2031	21.1	3.4	27.4	0.8	16.5	2.6	49.4	7.9
2032	18.1	2.9	23.1	0.7	22.0	3.5	50.0	7.9
2033	13.5	2.2	16.4	0.5	15.0	2.4	35.3	5.6
2034	12.6	2.0	15.1	0.4	17.3	2.8	36.0	5.7
2035	10.7	1.7	13.0	0.4	19.5	3.1	35.4	5.6
2036	9.1	1.4	11.3	0.3	21.4	3.4	34.9	5.5
2037	8.0	1.3	10.0	0.3	23.6	3.8	35.4	5.6
2038	6.8	1.1	8.3	0.2	23.6	3.8	33.5	5.3
2039	6.9	1.1	8.5	0.2	27.6	4.4	37.7	6.0
2040	6.5	1.0	8.0	0.2	28.5	4.5	38.0	6.0
2041	6.1	1.0	7.5	0.2	28.9	4.6	37.7	6.0
2042	5.7	0.9	7.0	0.2	29.4	4.7	37.5	6.0
2043	4.8	0.8	5.9	0.2	27.6	4.4	34.6	5.5
2044	5.0	0.8	6.1	0.2	31.3	5.0	38.5	6.1
2045	4.7	0.7	5.7	0.2	29.9	4.8	36.6	5.8
2046	4.2	0.7	4.9	0.1	24.0	3.8	29.8	4.7
2047	3.9	0.6	4.5	0.1	23.1	3.7	28.4	4.5
Cum Oil (MB / Mm3)	**122.0**	**19.4**	**163.9**	**4.6**	**165.5**	**26.3**	**356.5**	**56.7**

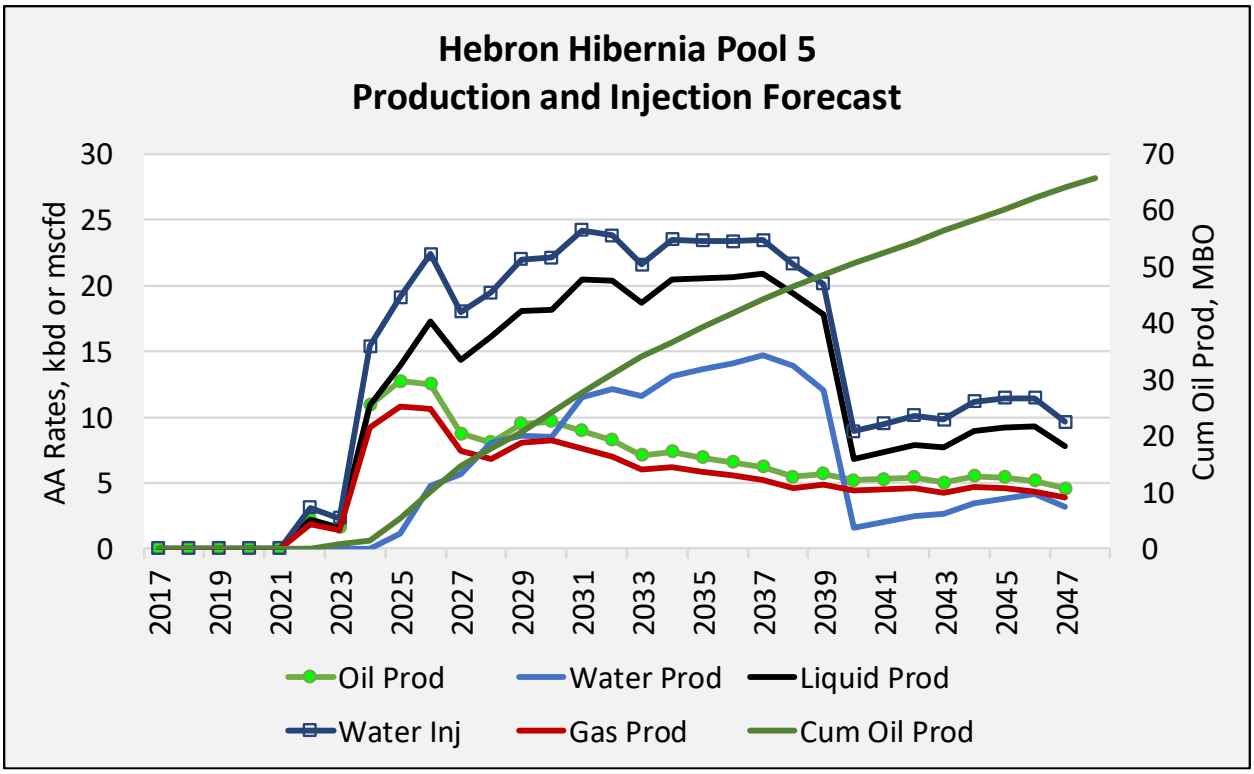


Figure 5-9 Hebron Pool 5 Production and Injection Forecast

Table 5-10 Hebron Pool 5 Production and Injection Forecast

Year	Oil Production		Gas Production		Water Production		Water Injection	
	kbd	km3/d	Mscfd	MSm3/d	kbd	km3/d	kbd	km3/d
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	2.2	0.4	1.9	0.1	0.0	0.0	3.1	0.5
2023	1.6	0.3	1.4	0.0	0.0	0.0	2.3	0.4
2024	10.9	1.7	9.2	0.3	0.0	0.0	15.4	2.4
2025	12.7	2.0	10.8	0.3	1.1	0.2	19.1	3.0
2026	12.5	2.0	10.6	0.3	4.7	0.8	22.4	3.6
2027	8.7	1.4	7.4	0.2	5.6	0.9	18.0	2.9
2028	8.1	1.3	6.8	0.2	8.1	1.3	19.5	3.1
2029	9.5	1.5	8.0	0.2	8.6	1.4	22.0	3.5
2030	9.7	1.5	8.2	0.2	8.5	1.3	22.1	3.5
2031	9.0	1.4	7.6	0.2	11.5	1.8	24.2	3.8
2032	8.2	1.3	7.0	0.2	12.1	1.9	23.8	3.8
2033	7.1	1.1	6.0	0.2	11.6	1.8	21.6	3.4
2034	7.3	1.2	6.2	0.2	13.1	2.1	23.5	3.7
2035	6.9	1.1	5.9	0.2	13.6	2.2	23.4	3.7
2036	6.6	1.0	5.5	0.2	14.1	2.2	23.4	3.7
2037	6.2	1.0	5.3	0.1	14.7	2.3	23.5	3.7
2038	5.5	0.9	4.6	0.1	13.9	2.2	21.6	3.4
2039	5.7	0.9	4.8	0.1	12.1	1.9	20.1	3.2
2040	5.2	0.8	4.4	0.1	1.6	0.3	8.9	1.4
2041	5.3	0.8	4.5	0.1	2.0	0.3	9.5	1.5
2042	5.4	0.9	4.6	0.1	2.5	0.4	10.1	1.6
2043	5.0	0.8	4.3	0.1	2.7	0.4	9.8	1.6
2044	5.5	0.9	4.7	0.1	3.4	0.5	11.2	1.8
2045	5.4	0.9	4.6	0.1	3.8	0.6	11.4	1.8
2046	5.1	0.8	4.4	0.1	4.2	0.7	11.4	1.8
2047	4.6	0.7	3.9	0.1	3.2	0.5	9.6	1.5
Cum Oil (MB / Mm3)	**65.7**	**10.5**	**55.6**	**1.6**	**64.5**	**10.3**	**157.4**	**25.0**

5.5 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 (GL) is the preferred artificial lift method and so some 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.

1. 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 in association with oil produced. The current subsurface license was issued and effective for a term of 3 years commencing October 1, 2020.
2. Gas injection in the I-13 block (Pool 1) through the use of 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.
3. 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 as 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.

Long-term annual average operational gas requirements (sum of fuel gas and background flare volumes) is anticipated to be approximately 22 Mcfd (0.6 Mm3 d). 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 long-term gas balance will also depend on the potential future development of Hebron area resources beyond those included in the planned development (Pools 1, 4, and 5).

Table 5-11 Gas Utilization Volumes provides an estimate of the total gas utilization volumes. It should be noted that the GL volumes circulate within the production system.

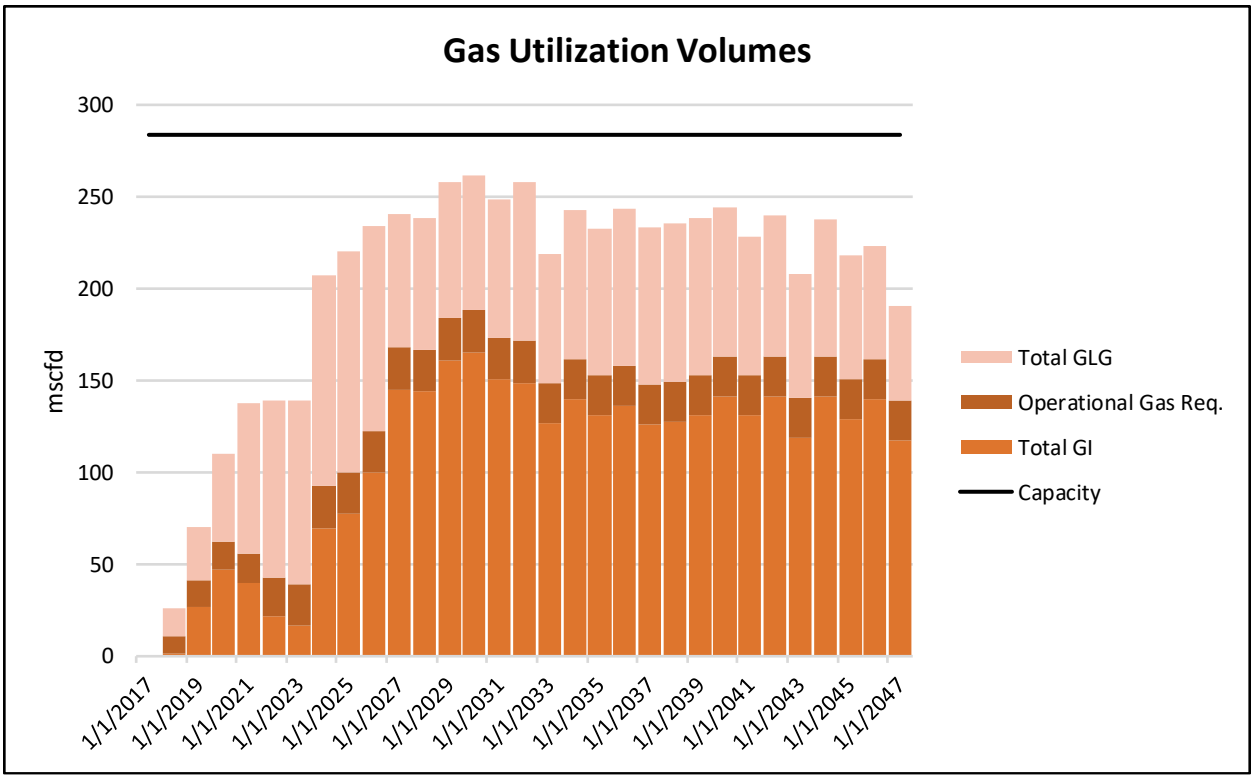


Figure 5-10 Gas Utilization Volumes

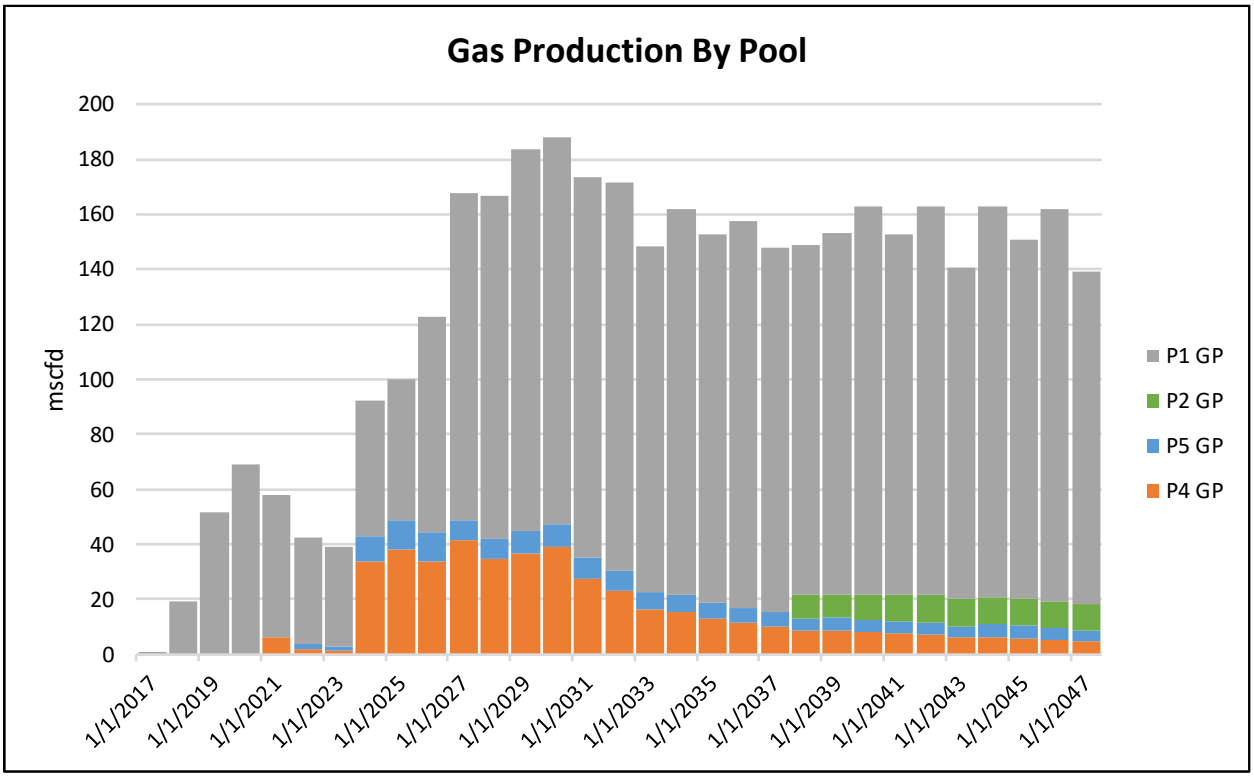


Figure 5-11 Gas Production by Pool

Table 5-11 Gas Utilization Volumes

Year	Oilfield Units, Mscfd				Metric Units, MSm3/d			
	Gas Production	Operational Gas	Gas Injection	Gas Lift	Gas Production	Operational Gas	Gas Injection	Gas Lift
2017	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	19.0	9.6	1.1	15.4	0.5	0.3	0.0	0.4
2019	51.3	14.4	26.5	29.3	1.4	0.4	0.7	0.8
2020	69.0	15.6	46.7	47.3	1.9	0.4	1.3	1.3
2021	57.8	16.2	39.4	81.8	1.6	0.5	1.1	2.3
2022	42.4	21.1	21.4	96.4	1.2	0.6	0.6	2.7
2023	38.9	22.9	16.0	100.3	1.1	0.6	0.5	2.8
2024	92.4	22.9	69.5	115.1	2.6	0.6	2.0	3.2
2025	100.1	22.9	77.2	120.5	2.8	0.6	2.2	3.4
2026	122.5	22.9	99.6	111.4	3.5	0.6	2.8	3.1
2027	167.7	22.9	144.8	73.2	4.7	0.6	4.1	2.1
2028	166.7	22.9	143.8	71.5	4.7	0.6	4.1	2.0
2029	183.7	22.9	160.8	74.4	5.2	0.6	4.5	2.1
2030	188.2	22.9	165.4	73.3	5.3	0.6	4.7	2.1
2031	173.5	22.9	150.6	75.1	4.9	0.6	4.2	2.1
2032	171.4	22.9	148.6	86.3	4.8	0.6	4.2	2.4
2033	148.1	21.7	126.4	70.6	4.2	0.6	3.6	2.0
2034	161.7	21.7	140.0	81.3	4.6	0.6	3.9	2.3
2035	152.5	21.7	130.8	79.9	4.3	0.6	3.7	2.3
2036	157.6	21.7	135.9	86.2	4.4	0.6	3.8	2.4
2037	147.9	21.7	126.1	85.8	4.2	0.6	3.6	2.4
2038	148.9	21.7	127.1	86.6	4.2	0.6	3.6	2.4
2039	153.0	21.7	131.2	85.8	4.3	0.6	3.7	2.4
2040	163.0	21.7	141.2	81.0	4.6	0.6	4.0	2.3
2041	152.6	21.7	130.9	75.6	4.3	0.6	3.7	2.1
2042	162.6	21.7	140.9	77.5	4.6	0.6	4.0	2.2
2043	140.7	21.7	119.0	67.5	4.0	0.6	3.4	1.9
2044	163.0	21.7	141.3	74.8	4.6	0.6	4.0	2.1
2045	150.7	21.7	129.0	67.1	4.2	0.6	3.6	1.9
2046	161.6	21.7	139.9	61.4	4.6	0.6	3.9	1.7
2047	139.1	21.7	117.4	51.8	3.9	0.6	3.3	1.5

6 Hydrocarbon Resource Estimates

6.1 Overview

Original in place oil volumes are calculated for each Jeanne d'Arc sand interval within the main Hebron Horst block and adjacent fault blocks (e.g., B') where cross fault juxtaposition is indicative of a connected oil system across block bounding faults. The STOOIP for these adjacent fault blocks is captured as high side to reflect uncertainty associated with the fluid contacts and the possibility of shallower perched contacts. The fluid contact assumptions for each sand are described in Section 2.1.3, as are the juxtaposition relationships associated with connected oil legs (i.e., oils assumed to be in pressure communication independent of sand). These proposed pools are outlined in Figure 1-2. The proposed 'composite' pools are detailed in Section 2.1.3 and adopt the naming convention of the Horst

block oil that is the basis of each respective pool from a pressure data perspective. For example, the proposed C Sand pool is a composite of C Sand in the main Horst block and its interpreted extension to the south into E' block H Sand and F' block E/D Sands (as shown in Figure 2-34).

6.2 Methodology

Original in place oil volumes are calculated in the geologic model as described in Section 3.7.1. The H Sand North Valley (M-04) in place volumes are calculated utilizing the 2021 best estimate geologic model, as described in Section 3.7.1.1. The methodology utilizes the gross rock volume calculated from the flexed model surfaces, the property model, and the assumed fluid contacts. Specifically, net sand is distributed as per the Environment of Deposition (EOD) maps shown in Section 2.1.2.1 and the porosity of net sand is calculated in the model using well logs and geological concepts. Permeability is calculated from porosity, using a porosity-permeability transform, and water saturation is calculated using the unified saturation height function described in Section 3.4.1 and shown in Figure 3-8. Oil Formation Volume Factors (FVF) vary by sand, as shown in Table 3-2.

6.3 Original Hydrocarbon in Place Estimates

Original in place oil volumes (STOOIP) are shown in Table 6-1 and are organized by sand and fault block(s). In all cases, the Main, Ramp, and NE Segment as shown in Figure 4-1 (collectively, 'Horst') are interpreted to be in pressure communication within a given sand. However, while the C Sand Main portion only is shown as the proposed pool in Figure 2-34, some additional oil in place is calculated in the Ramp, NE Segment, and A' Blocks (Table 6-1) because these portions are above the penetrated C Sand OWC penetrated by L-93 29 (but may not be in communication with the C Sand Main block oil leg). As described in Section 2.1.3, sands in adjacent fault blocks that have significant juxtaposition with oil-bearing sands in the main Horst block are assumed to be oil bearing and in pressure communication on a geological timescale. Note that for the adjacent fault blocks, uncertainty in oil water contact remains owing to potential unmapped structural or stratigraphic configurations that could cause intra-fault block perched water. This potential perched water could reduce significantly the STOOIP in unpenetrated fault blocks (e.g., Lower Hibernia Sand in E' Block). As such, the in place oil volumes shown in Table 6-1 for B'-F' Blocks are likely high-side estimates. The distribution of STOOIP (MBO) is shown on the proposed composite pool maps in Figure 6-1. Low side and high side estimates are based on the presence of reservoir rock. The EOD is fluvial with uncertainty in the extent and presence of connected sand. The low and high side estimates are derived by ranging the pore volume as a proxy to sand presence and quality.

Table 6-1: Original in place oil volumes by Sand and Fault Block (no cutoff).

		Low Side		Best Estimate		High Side	
Sand	**Fault Block**	**STOIIP ($10^6 m^3$)**	**STOIIP (MBO)**	**STOIIP ($10^6 m^3$)**	**STOIIP (MBO)**	**STOIIP ($10^6 m^3$)**	**STOIIP (MBO)**
H North Valley	**Horst**	27.0	170	27.0	170	39.0	245
H Sand	**Horst, A'**	0.5	3.2	0.9	5.9	1.4	8.9
G sand	***Horst, A'***	6.1	*38.5*	12.2	*76.9*	18.3	*115.4*
F Sand	***Horst, A'***	4.6	*29*	9.3	*58.3*	13.9	*87.5*
E Sand	**Horst, A'**	4.5	28.1	5.9	37.4	8.9	56.1
D Sand	***Horst, A'***	0.9	*5.6*	1.8	*11.4*	2.7	*17.1*
C Sand	**Horst, A'**	7.4	46.3	14.6	91.9	21.9	137.9
B Sand	**Horst, A'**	13.3	83.5	17.7	111.4	26.6	167
C Sand	**B'**	-	-	-	-	1.2	7.8
C Sand	**C'**	-	-	-	-	9.8	61.7
C Sand	**E'**	-	-	-	-	2.0	12.8
H Sand	**E'**	-	-	-	-	1.8	11.2
LHS	**E'**	-	-	-	-	26.9	169
C Sand	**F'**	-	-	-	-	3.0	18.9
Total		**64.3**	**404.2**	**89.6**	**563.2**	**177.5**	**1116.3**

Solution gas was also calculated for the Jeanne d'Arc Formation sands and is shown in Table 6-2.

Table 6-2: Solution gas volumes by Sand and Fault Block

		Low Side	Best Estimate	High Side
Sand	**Fault Block**	**Solution GIIP ($10^9 m^3$)**	**Solution GIIP ($10^9 m^3$)**	**Solution GIIP ($10^9 m^3$)**
H North Valley	**Horst**	2.8	2.8	4.0
H Sand	**Horst, A'**	0.1	0.1	0.2
G sand	***Horst, A'***	0.8	1.5	2.3
F Sand	***Horst, A'***	0.6	1.1	1.7
E Sand	**Horst, A'**	1.8	2.4	3.6
D Sand	***Horst, A'***	0.4	0.7	1.1
C Sand	**Horst, A'**	2.2	4.3	6.4
B Sand	**Horst, A'**	4.2	5.6	8.4
C Sand	**B'**	-	-	0.2
C Sand	**C'**	-	-	1.2
C Sand	**E'**	-	-	0.6
H Sand	**E'**	-	-	0.5
LHS	**E'**	-	-	3.3
C Sand	**F'**	-	-	0.9
Total		**12.7**	**18.6**	**34.5**

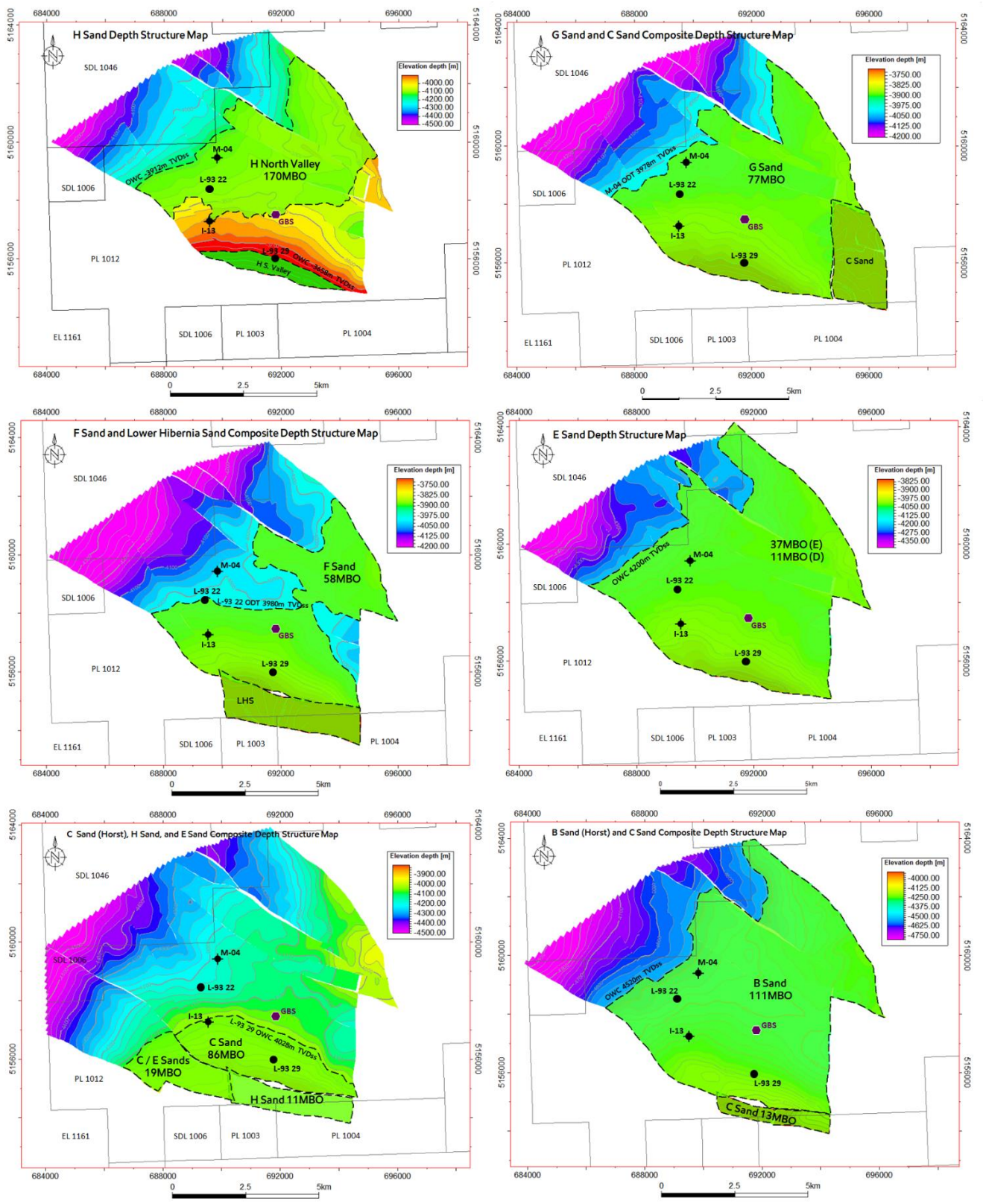


Figure 6-1: Proposed composite pool maps from Section 2.1.3 annotated with in place oil volumes (MBO STOOIP, no cutoff) from Table 6-1.

6.4 Recoverable Resource Estimates

Recoverable oil estimates are shown in Table 6-3 and are based on the development well plans described in Section 4. Note that there are development wells described for the Horst block, Ramp, and NE Segment only. As such, the EUR and Recovery Factor (RF) described below are associated only with this suite of development wells. Given the potential for connected oils in adjacent fault blocks (Table 6-1), future development potential remains.

The EUR associated with H North Valley, E, C, and B sands relate to dedicated producers and injectors and therefore have a recovery factor in the range of 25-32%. The G, F, and D Sand EUR, however, is associated with a single comingled oil producer with no injection support, as described in Section 4.4.2, and therefore has a much lower recovery factor. Low side and high side scenarios recovery factor scenarios are incorporated in the table below.

Table 6-3: Estimated Ultimate Recoverable oil volume by Sand within the main Horst Block as per the development scheme described in Section 4.

		Low Side		Best Estimate		High Side	
Sand	**Fault Block**	**EUR (10^6m^3)**	**EUR, MBO**	**EUR (10^6m^3)**	**EUR, MBO**	**EUR (10^6m^3)**	**EUR, MBO**
H North Valley	**Horst**	5.7	36	8.1	50.7	11.4	72
H Sand	**Horst, A'**	-	-	-	-	0.5	3.1
G sand	***Horst, A'***	0.17	*1.05*	0.33	*2.1*	6.4	*40.4*
F Sand	***Horst, A'***	0.13	*0.79*	0.25	*1.6*	4.9	*30.6*
E Sand	**Horst, A'**	0.89	5.62	1.81	11.4	3.1	19.6
D Sand	***Horst, A'***	0.02	*0.15*	0.05	*0.3*	1.0	*6.0*
C Sand	**Horst, A'**	1.47	9.26	4.43	27.8	7.7	48.3
B Sand	**Horst, A'**	2.66	16.70	4.48	28.2	9.3	58.5
C Sand	**B'**	-	-	-	-	0.4	2.3
C Sand	**C'**	-	-	-	-	2.9	18.5
C Sand	**E'**	-	-	-	-	0.6	3.8
H Sand	**E'**	-	-	-	-	0.5	3.4
LHS	**E'**	-	-	-	-	8.1	50.7
C Sand	**F'**	-	-	-	-	0.9	5.7
Total		**11.1**	**69.6**	**19.4**	**122.1**	**57.7**	**362.9**

Connectivity of the sands remains the greatest uncertainty in determining EUR. Recovery factors range from 3% for the G, F and D sands where reservoir quality and lateral extent influence reservoir connectivity, to 30% for the E sand where the limited dynamic data support the current estimates of connected volume. The EOD of these sands is fluvial which can manifest as limited to no connectivity between channel bodies to fully amalgamated channel sands. Dynamic data collected during the early phases of development will be incorporated and used to update recoverable resource estimates and inform future well decisions which will also include the rimming fault blocks.

The EUR summary for all the Hebron Pools is shown in Table 6-4.

Table 6-4: Hebron Integrated Flowstream EUR Summary by Pool

EUR	Orig Dev Plan		2021 APR		2022 JdA DPA	
	MB	Mm3	MB	Mm3	MB	Mm3
Pool 1	563	89.5	616	97.9	616.6	98.0
Pool 5	15	2.4	41	6.5	65.7	10.5
Pool 4	87	13.8	79	12.5	122.0	19.4
TOTAL	**665.0**	**105.7**	**735.9**	**117.0**	**804.4**	**127.9**

7 Summary

Additional Jeanne d'Arc Formation resources are the primary focus of this Development Plan Amendment (DPA) application. Development of these sands is the next step to optimizing Hebron area resources and will assist in offsetting the natural decline in production at Hebron.

The JDA Formation is the deepest reservoir at Hebron and is Kimmeridgian to Tithonian in age. The topmost (H) and bottommost (B) sands were included in the Development Plan as sufficient data were available to progress a reservoir exploitation plan. This application extends the development of the JDA Formation to include additional sands depositionally related to the H and B sands. The area proposed for development sits directly below the Hebron Platform and includes the Hebron Horst Block and small fault blocks to the east and south where reservoir is juxtaposed against reservoir. Inclusion of these fault blocks is intended to capture the full extent of the hydrocarbon accumulation such that development of the accumulation is optimized.

The displacement strategy for the JDA Formation sands includes secondary recovery by waterflood. The existing secondary recovery mechanism of water displacement will be maintained however, other development strategies may be tested to optimize reservoir performance as new information becomes available. The proposed depletion plan is anticipated to recover approximately 7 Mm3 or 43 MBO from the JDA Formation sands from six additional wells utilizing existing facilities. While offsetting natural decline in production, the additional JDA Formation wells will not materially impact volumes throughput or emissions associated with the Hebron Development and remains within the range of estimates in the original CSR.

Currently, gas produced from the development at Hebron is injected into the Ben Nevis Formation at Pool 2, and in the I-13 Block as part of a water-alternating gas strategy. The revised Hebron depletion plan (2020) also considers future optionality for injection into the crest of the Horst Block. Over the life of the field, gas production is expected to be 4.1 Msm3/d with 0.6 Msm3/d for operational, 3.5 Msm3/d for gas injection and 1.5 Msm3/d for gas lift. ExxonMobil will continue to evaluate opportunities to develop the Hebron gas resource, however; the current plan is to use gas in support of oil recovery. Produced gas will continue to provide primary power to the Hebron Platform.

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