Offshore Newfoundland & Labrador Resource Assessment
Carson-Bonnition-Salar NL19-CFB01

An Integrated Project for Nalcor Energy – Oil and Gas Inc., and the Department of Natural Resources, Government of Newfoundland and Labrador

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INTRODUCTION

Nalcor Energy – Oil and Gas Inc., Newfoundland and Labrador’s provincial energy corporation working with the Newfoundland and Labrador Department of Natural Resources (DNR), engaged Beicip-Franlab to conduct an independent resource assessment of the Carson, Bonnition and Salar basins area following the resource assessments of the Flemish Pass (NL15_01EN); Orphan basin area (NL16-CFB01) and eastern Jeanne d'Arc (NL18-CFB01) and Orphan/Flemish basins (NL18-CFB02) in 2015, 2016 and 2018. The Carson, Bonnition and Salar basins belong to the same type of rifted basin as the prolific Jeanne d’Arc and Flemish Pass basins but have yet to demonstrate their petroleum potential. Their exploration level remains low, as only four wells have been drilled over the shelf only. The objective of this project was to conduct a geological and geophysical interpretation, basin analysis, play risk analysis, and resource assessment for the area subject to the upcoming license round (NL19-CFB01 November 2019) based on available geological and geophysical data. The final deliverables of this project included a detailed Beicip-Franlab internal report for Nalcor and DNR as well as this Public Atlas which summarizes the main methodologies and key results of the resource assessment project.

WORKFLOW

1. Database generation and QC
2. Seismic interpretation and restoration
3. Geodynamic and tectonic settings
4. Sedimentology, seismic stratigraphy

MAIN RESULTS

The Beicip-Franlab petroleum system resource assessment of the Carson, Bonnition and Salar basins area demonstrates a potential petroleum system with seven potential reservoirs sourced by regionally known source rocks. The timing of burial with respect to traps formation enables hydrocarbons (HC) to be trapped and sealed regionally through rotated Jurassic blocks and associated structural traps, as well as stratigraphic traps in the Early Cretaceous and Paleogene. Several geological scenarios have been tested, all being calibrated on well data and seismic features. They show the likelihood of an efficient petroleum system in the Carson-Salar basin area.
STUDY AREA

The southeastern Newfoundland jurisdiction represents part of the north Atlantic Mesozoic rift system. It includes the Carson, Bonnition and Salar basins. In January 2019, Nalcor Energy – Oil and Gas Inc. and Beicip-Franlab began the resource assessment of this area. On April 3, 2019, the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) announced the Call for Bids NL19-CFB01. The block definition includes nine parcels of land. The land available in the call is under the new Scheduled Land Tenure System:


Interested parties have until 12:00 p.m. NST on November 6th, 2019 to submit bids for the parcels offered in Call for Bids NL19-CFB01. Further detailed information pertaining to this Call for Bids can be found at: https://www.cnlopb.ca/exploration/issuance/#bids-active.
DATA SET

1. **Seven (7) wells** were used for the study. Each well contains a set of petrophysical logs, stratigraphic markers, and geochemical reports:
   - Bonnition H-32
   - Cormorant N-83
   - Murre G-67
   - Osprey H-84
   - Skua E-41
   - Spoonbill C-30
   - St George J-55

2. **2D seismic surveys** (regional, 10x10km and 5x5km grids) interpreted by Nalcor and covering an area of 58,000 km² within the Carson, Bonnition, Salar basins area (From 2014-2017, Nalcor invested TGS/PGS broadband long offset multiclient Southeast Grand Banks Seismic Project).

3. **A set of fifteen (15) horizons** were interpreted in the 2D surveys and 14 associated isopach maps:
   - Seabed, 0 My
   - C34, Top Eocene, 34 Ma
   - C45, Top Mid Eocene, 45 Ma
   - C54, Top Paleocene/Base Eocene
   - C65, Top Cretaceous, 65 Ma
   - K100, Top Albian, 100 Ma
   - K114, Top Mid Aptian, 114 Ma
   - K140, Top Berriasian, 140 Ma
   - J145, Top Tithonian, 145 Ma
   - J151, Top Kimmeridgian , 151 Ma
   - J165, Top Bathonian, 165 Ma
   - J185, Top Pleinsbachian, 175 Ma
   - J195, Top Hettangian, 195 Ma
   - T201, Top Triassic, 201 Ma
   - Base Mesozoic, 251 Ma

4. **Fault sets** picked for structural evolution and 3D modelling.

The 2019 Carson, Bonnition and Salar basins Resource Assessment study area shares its northern boundary with the 2018 NL03-EN-01A sector. Nalcor and Beicip-Franlab extended the main structural trends, seismic horizons, and paleogeographic interpretation from the Flemish Pass Basin and eastern Jeanne d’Arc Basin to the Carson, Bonnition and Salar basins to ensure regional consistency.
BUILT-ON KNOWLEDGE

DATA SET REVIEW AND RELEVANCY

Regional seismic interpretation - The seismic interpretation of the sector covers the entire Mesozoic to present day. It is calibrated with the various wells available in the study area. The regional seismic interpretation based on a 5x5km (approximate) grid is adapted to the play study scale. It identifies the main traps (with a minimum of 8 km²), the main structural features (deposcentres, slopes, main regional faults), seismic response of the regional paleo-environment settings, as well as seismic objects and anomalies that may correspond to sedimentary features such as channels, deep sea fans, etc. This interpretation highlights structural traps with minimal in-place volumes in the order of 80 MMbbl equivalent (~10 Mm³) or higher.

Well geological data - The study also uses the comprehensive well information of seven (7) wells within the study area and its vicinity. It includes: well logs, paleo-environment data, temperature, pressure, and HC recordings, along with regional geological studies on eastern NL and existing well correlations. This data provides a reliable framework for the play definition, internal subdivisions, and key characteristics of the wells such as net-to-gross, reservoir intervals, average porosities, carriers, and seals occurrence.

Geochemical and petroleum data - Maturity data recorded in wells are abundant (Ro, Tmax). TOC measurements are acquired from cuttings and cores. The existence of a proven and efficient petroleum system in the neighboring basins (Jeanne d’Arc and Flemish Pass), with similar geological characteristics, provides a useful analogue for the Kimmeridgian source rock characterization.

Reliability and accuracy of the resources assessment - The data quality ensures that reliable and reasonably well-constrained 3D geological models of the area can be built. Several scenarios have been considered. All scenarios have to be calibrated against sand shale ratio, thicknesses and TOC observed at well data. Some scenarios have been discarded for not honoring well data, interpreted seismic features and HC occurrence forecasts. The corresponding oil and gas resource assessment can be undertaken with greater accuracy covered through the low and high cases of the different calibrated scenarios.

Experimental design: scenario tree

- Geodynamic interpretation allows two basin-drowning hypotheses to be addressed.
- Some seismic geomorphological evidence supports some carbonate presence.
- Given the understanding of the tertiary deposits, often bypassed at well (all within the platform) the sand-shale ratio is tested here as a different hypothesis.
- Given the understanding of the exact paleogeography in the basin, two equiprobable hypotheses are addressed in the Jurassic and Cretaceous: open oxygenated marine conditions (oxic) and layered anoxic conditions. As the Cenozoic is not mature because of insufficient burial, no organic matter simulation is tested.
HYDROCARBON PLAY RESOURCE ASSESSMENT METHODOLOGY

- The hydrocarbon (HC) play resource assessment methodology follows the Petroleum Resources Management System (PRMS) Guidelines (2018) for Prospective and Contingent Resource assessment. The 2018 Guidelines include the PODS (Probability of Development success). The PODS was not considered in this study.
- The assessment was based on the deterministic computation of oil and gas volumes in place in the area of interest. The simulations include 3D numerical geological models of lithofacies distribution (sedimentary system modelling) and of 3D structural oil and gas generation/expulsion/migration and entrapment (petroleum system modelling). The software packages used are DionisosFlow™ (for sedimentation) and TemisFlow™ 3D (for petroleum system).
- Several geological scenarios were computed, being considered as calibrated against data on reservoir and seal presence, source rock presence and maturity, HC shows (sea bottom seeps, AVO anomalies) and well post-mortem analyses.
- The sedimentary system model was calibrated against well data on sand-shale ratio, paleo water depth, and known depositional setting at the wells (shoreface, shelf, slope, etc.). The matching was done at a third order sequence stratigraphic scale resolution. The petroleum system model is calibrated against maturity, temperature, pressure data, oil and gas occurrence, and quality. The matching was done at the resolution of the 3D geological model used in the simulation, and the precision of data (i.e., Vitrinite ±0.15%).

Unrisked Volumes (Alternative calibrated models approach)
- The unrisked volumes of hydrocarbons correspond to the amount of oil (Bbl), gas (Tcf) and oil+gas (in Bboe) that can be present in the plays according to several calibrated geological scenarios.
- The HC volumes of each scenario have been computed using a 3D integrated Darcy model of HC migration and entrapment and post processed using the Trap Charge Assessment (TCA) module applied to the various plays. Each scenario includes a low, best and high HC volume estimate, which is given by cutoff values applied to the HC mass in place / km² in the reservoir layers of the 3D model. The TCA module has been used to test the impact of the seal efficiency for a given HC charge in a reservoir play.
- The following scenarios have been tested:
  - For reservoir and seal distribution: fast drowning or slow drowning during Late Jurassic and Cretaceous times, with or without carbonate deposits.
  - For source rock potential: anoxic or oxic environment.
  - For seal efficiency: low seal efficiency (low top reservoir capillary pressure) and high seal efficiency (perfect barrier).
- The scenarios and their outcomes using the cutoff values on HC concentrations have been compared to the observations made at wells (dry wells in the Study Area), TOC values, presence of HC sea bottom seeps, and AVO anomalies. Some outcomes were rejected as they contradicted the observations.
- The remaining outcomes were considered as equiprobable and were used to obtain an unrisked volume distribution.

PRMS Guidelines 2018:
EXPLORATION HISTORY

The drilling of Tors Cove D-52 in the early 1960s marked the beginning of hydrocarbon exploration in Newfoundland and Labrador’s offshore. To date, nearly 160 exploration wells have been drilled. Many other wells have been drilled in the Jeanne d’Arc Basin that were related to the development of five producing fields. Production to date has been in excess of 1.8 billion barrels of oil. The NL19-CFB01 area is situated southeast of the producing Jeanne d’Arc Basin, and directly south of the NL03-EN-01B area that was part of the 2018 Resource Assessment.

Throughout the 1960s and 1970s, exploration within the Newfoundland and Labrador offshore region focused mainly on the shallow waters of the present day shelf, occurring from southern Newfoundland to the coast of Labrador. Within the Southeastern Newfoundland offshore jurisdiction, focus has been on the shallow water shelf regions, with the slope and vast deepwater regions of the Call for Bids (CFB) area, NL19-CFB01, unexplored.

There are three wells included within this assessment that are situated within the CFB area. Bonnition H-32 was drilled in 1973 by Mobil and Gulf on the western margin of the Bonnition basin. This well encountered thin sandstones within the Early Cretaceous (Berriasian), and reached total depth within the Tithonian-aged sediments. The Skua E-41 well was drilled on the western margin of the Carson basin in 1974 by Amoco, Imperial, Skelly and Chevron. This well encountered sandstones of reservoir quality within the Cretaceous (Berriasian), as well as some marginal reservoir sandstones in the Middle Jurassic (Bathonian). This well has undergone significant erosion in the Late Jurassic, with Early Cretaceous overlying unconformably Callovian to Oxfordian-aged (Riley, 2013) sediments and reached total depth within the Callovian-aged interval. The St. George J-55 well was drilled in 1986 by Canterra and Petro-Canada on the western margin of the Bonnition basin, approximately 13.5 km southwest of the Bonnition H-32 well. St. George J-55 encountered a thick (approximately 600m MD) reservoir unit within the Early Cretaceous (Berriasian). This well reached total depth within the Tithonian-aged interval.

Just outside the Study Area, Osprey H-84 was drilled in 1974 by Amoco, Imperial, Skelly and Chevron on the southern extent of the Carson basin, 82 km southwest of Skua E-41. This well encountered Tertiary sediments, overlying a thin Late Cretaceous interval, which is overlying approximately 2200mMD of Late Triassic to Early Jurassic salt interbedded with thin shale and limestone. Underlying this interval is a Triassic aged interbedded sandstone, siltstone and shale at total depth. Approximately 76 km southwest of the Osprey H-84 well, the Jaeger A-49 well was drilled in 1972 by Amoco and Imperial. This well is drilled on the basement ridge between rift basins and encountered passive Tertiary and Late Cretaceous sediments above basement volcanics, described within the end of well report as granodiorite, with a minimum age of 376 Ma (Mid-Devonian).

Approximately 280 km east of the St. George J-55 well, the Ocean Drilling Program (ODP) Leg 210 Hole 1276 was drilled in 2003. This well encountered thick, organic shale events with high total organic carbon within the Cenomanian-Turonian and latest Albian intervals. This well reached total depth in Albian-aged diabase sills. The ODP Leg 210 Hole 1277 was drilled 37 km southeast of Hole 1276 and encountered serpentinized peridotite believed to be associated with formation of oceanic crust.

In 2014, ExxonMobil Canada Ltd. and Suncor Energy Offshore Exploration Partnership purchased Exploration License (EL) 1136 within the southeast Newfoundland jurisdiction. In 2016, Total E&P Canada Ltd. farmed in on this Exploration License with current interest holdings being ExxonMobil Canada Ltd. 33.34%, Suncor Energy Offshore Exploration Partnership 33.33% and Total E&P Canada Ltd. 33.33%. Within the EL1136 and extending west into the Study Area, tying the St. George J-55 and Bonnition H-32 wells, TGS and PGS acquired a multiclient 3D seismic survey (Cape Broyle 3D) from 2017 to 2018 acquisition seasons. An application to drill one to five wells on EL1136 has been submitted for Environmental Assessment approval by ExxonMobil Canada Ltd.

With the emergence of Nalcor Energy, Newfoundland and Labrador’s crown energy company, in 2007 a commitment was made to invest in new geoscience data to unlock the next offshore areas that may contain material prospectivity. In late 2010, with Airbus Defense and Space, Nalcor undertook a regional oil seep mapping and interpretation study encompassing all of offshore Newfoundland and Labrador (over 1.5M km²). To understand better the potential nature of prospectivity in this region, in 2014 Nalcor began to invest with global seismic companies TGS and PGS in a long offset broadband 2D multi-client seismic grid of space data over the Southeast Newfoundland jurisdiction. This survey was an extension of the 2011-2014 Nalcor invested TGS and PGS regional 2D seismic program targeting the slope and deepwater areas offshore Newfoundland and Labrador.

From 2015 to 2017, further acquisition in the Southeast Newfoundland jurisdiction continued within the NL19-CFB01 area. In 2017, the NL19-CFB01 was almost entirely covered by a 5 x 5 km grid of broadband 2D seismic data. This data forms the foundation for the insights into development of a petroleum system model for the NL19-CFB01 region.

In 2018, Nalcor partnered with Fugro in the Southeast Newfoundland jurisdiction and conducted a seabed coring survey where cores taken were analyzed for hydrocarbon response. The result being that this area displayed multiple indications of a thermogenic hydrocarbon response, throughout the NL19-CFB01 region.
REGIONAL GEODYNAMIC AND STRUCTURAL ELEMENTS

The northeast edge of Newfoundland was subject to two consecutive rifting episodes. The first one, NW-SE-oriented, occurred in the Late Jurassic – Early Cretaceous and is related to the continental dislocation between North America and Iberia Plates. The second, NE-SW-oriented, rift phase occurred during the Early Cretaceous and is related to the separation between the North America and Eurasia Plates. Mesozoic basins lying at the northeast edge of Newfoundland (Grand Banks) are recording this complex geodynamic evolution. The Charlie-Gibbs Fracture Zone and the Orphan Knoll just west of the Continent Ocean Transition (COT) mark the northern limit of the Orphan Basin. The Flemish Cap, an unstretched continental block, and the Bonavista platform bound respectively the eastern and western limits of the Orphan Basin. A strong positive free air gravimetry anomaly (the Cumberland Transfer Zone) forms the limit between Jeanne d’Arc, Carson, Bonnition and Salar basins with Orphan and Flemish Pass basins. A seismic refraction profile (SCREECH3) across the Jeanne d’Arc, Carson and Salar basins reaches the oceanic crust beyond the M0 magnetic anomaly and revealing thinned continental crust below the Salar basin and serpentinized mantle seaward.
PLATE KINEMATICS

The eastern margin of Canada experienced successive rift episodes since Late Triassic times, propagating northward eventually leading to the rifting between Newfoundland and Iberia margins and then Newfoundland and Irish margins.

A diachronous NW-SE-oriented extension characterized the Newfoundland – Iberia rifting phase. The Early Jurassic extension reaches the southern province of Newfoundland, South Whale, Whale and Horseshoe basins (Welsink and Tankard, 2012).

Rifting between Central Newfoundland and Iberia started in the Late Callovian. The final separation between Flemish Cap and Iberia (Galicia Bank) occurred in the "mid"-Cretaceous. The age is still debated with the oldest proposed age of latest Barremian – earliest Aptian (Russell and Whitmarsh, 2003) and the youngest of late Aptian (Tucholke et al., 2007), or even younger in the Late Albion (Boillot and Winterer, 1988).

Continental extension eventually propagates further north leading to the rifting between the Newfoundland and Irish margins with a drastic change of the maximum horizontal stress from NW-SE to NE-SW. Generalized rifting occurs between the Flemish Cap-Goban Spur conjugate margins in the Early Barremian (128-126 Ma; de Graciansky et al., 1985). Post-rift sediments indicate a final breakup at 100 Ma.

The final phase of extension in the Orphan basin is marked by the Aptian-Albian Unconformity (Dafoe et al., 2017). The rifting continues toward the north in the Labrador Sea where extension began in the early Aptian and ended with the continental breakup in the late Maastrichtian (Dickie et al., 2011).

Tectono-thermal domains and margin segmentation history. Modified after Pichot et al, 2018; Welsink & Tankard, 2012; Welford et al, 2010

PH: Porcupine High; OK: Orphan Knoll; GbS: Goban Spur; FC: Flemish Cap; GB: Galicia Bank; RB: Rockall basin; PrCB: Porcupine basin; OB: Orphan basin; GbB: Goban Spur basin; FB: Flemish Pass basin; JdAB: Jeanne d'Arc basin; BB: Bonnition basin; SB: Salar basin; CB: Carson basin; WB: Whale basin; HB: Horseshoes basin; GiB: Galicia Interior basin; PrtB: Porto basin; PrNB: Peniche basin; LB: Lusitania Basin; AB: Alentejo basin
CRUSTAL STRUCTURES

In the Carson and Bonnition basins, large half graben crustal blocks are bounded by seaward-dipping low angle normal faults. These crustal faults seem to sole out somewhere into the middle continental crustal layer. The structural style present in the Carson and Bonnition basins can be compared to the Jeanne d’Arc Basin where no significant thinning of the continental crust occurred.

The Salar Basin is localized in a more distal position. Smaller crustal blocks are present. The spacing distance between faults are smaller than in the proximal Carson and Bonnition basins. Deep seismic reflection observed on the seismic reflection data match well with the depth of the Moho discontinuity interpreted by Lau et al., (2006) using refraction seismic profile (See, SCRREECH3 profile in Slide 10). The listric faults sole out at the Moho discontinuity. Crustal thinning prevails in the Salar Basin.

In a more distal area (SE Salar Basin), the morphology of the acoustic basement changes drastically. Refraction seismic profile reveals a high velocity gradient compatible with the subcontinental upper mantle. Normal planar faulting bounds tilted basement blocks. These faults seem to disappear at around 12 km of depth along a very distinctive reflector, probably witnessing the transition between serpentinized and unaltered mantle (like that seen in Jolivet et al. 2015).
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With deformation migrating west to east, the Carson, Bonnition and Salar basins initiated during the latest Triassic – Early Jurassic times. The main deformation is concentrated in the Carson-Bonnition basins (proximal domain).

This first rifting phase is followed by another extensive episode during the Late Jurassic to Early Cretaceous, which is more concentrated in the distal part of the margin. This latter rift phase is achieved by mantle exhumation as recovered by ODP Leg 210, hole 1277 in the Early Cretaceous.

In the proximal domain, Jurassic and older sediments are partly eroded as a result of the Avalon Uplift (Wade and MacLean, 1990) which developed beneath the Grand Banks coeval with the mantle exhumation.

During these periods of rifting, the subsidence in the Carson-Bonnition basins are mainly controlled by two major low-angle normal faults, interpreted as the reactivation of old Acadian (Caledonian) thrust faults. North to the Bonnition/Aveira transform fault, the extreme south of the Flemish Pass area shows a drastic change of fault vergence. These faults are primarily dipping towards the west.

### 2D SEQUENTIAL RESTORATION

**present day**

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**Late Bathonian**

**Late Jurassic**

**Early Cret**

**Late Aptian**

**Late Jurassic**

**Ovalon uplift**

**Ovalon uplift**

**Skua**

**St George**

**Section 3321**

**Section 3341**
Twelve depth maps were picked from the seismic grid and used to define the skeleton of present-day model geometry. Five are shown here for illustration purposes. In some cases, where surfaces converge, the older surface is replaced by a younger surface and the thickness between these two surfaces becomes zero. For modelling purposes, all surfaces have been mapped to the extent of the modelled regions.
In the stratigraphic modelling, subsidence represents the vertical movement of the basement through time. It is key to defining the accommodation space and its variation through time, thus driving in-situ sediment flux. Subsidence evolution is built after reconstructing the main tectono-stratigraphic sequences guided by structural maps (seismic interpretation), taking into account sediment compaction.

Eleven subsidence maps (at 195, 165, 151, 145, 134, 114, 100, 65, 54, 45, 34 Ma) have been used to guide the subsidence history of the basin from the Top Triassic to Tertiary.

Four main tectonic episodes shape the final basin geometry. The first tectonic event is an aborted Jurassic rift that develops a large subsidence in the Carson, Bonnition and Jeanne d’Arc Basin areas, extending to the west. The rift elongation is N145° along normal and strike slip faults.

The second tectonic event is a Late Jurassic rifting in a N130° direction, developing local horsts and grabens with normal and strike slip faults reactivation.

The third tectonic event corresponds to the Avalon uplift and affects the western part of the region.

The fourth event is the oceanic seafloor spreading starting during the late Early Cretaceous and leading to thermal subsidence and passive margin installation.
GEOLOGY & STRATIGRAPHIC FRAMEWORK: STRATIGRAPHIC CORRELATION

The stratigraphic framework has been updated to tie to well stratigraphic correlations and seismic interpretation. Main time markers (Base Mesozoic, T_200, J_185, J_165, J_151, J_145, K_140, K_114, K_100, C_65, C_54, C_45, C_34 and C_24) were picked guided by biostratigraphic interpretation. Well penetrations largely sample the Cretaceous and Late Jurassic levels. Aptian and top Cretaceous erosive events locally remove part of the stratigraphic records.
The interpretation, in terms of seismic stratigraphy, aims at identifying sedimentary bodies from seismic data. Three regional seismic cross-sections were chosen to define the key stratigraphic features of the margin. This southernmost NW-SE section highlights the infill of the depocenter located between the Carson Basin and southern portion of Salar Basin. Specifically, this section displays:

a) Thick Jurassic synrift continental to marginal marine deposits within the Carson and Salar basins. Those sediments are significantly eroded during the Avalon uplift in the Carson area.

b) A Cretaceous wedge in the Salar Basin recording the initial reworking of northern older Jurassic sediments eroded during the Avalon uplift (Late Jurassic to Early Cretaceous) and is overlaid by Albian post-rift shales.

A thick Tertiary succession is also noticeable in the northwestern part of the section. Progradation of this interval is toward the southeast.
SEQQUENCE STRATIGRAPHY AND DEPOSITIONAL ENVIRONMENTS

NW-SE Oriented Section – Line 3341

This central NW-SE section highlights the infill of the main Cretaceous depocenter located between the two main transform areas, within the Salar Basin.

Specifically, this section displays:

a) Jurassic marine deposits with detritic shale and sand,

b) Cretaceous fluvial plain to marine deposits sourced mainly from the eroded sediments to the west during the Avalon uplift.

Aptian canyon pathways recording this high energy depositional context are noticeable at the St George J-55 well in Bonnition Basin. At the same time, several depositional lowstand lobes are described in the Salar area.

Salt diapirs are also noticeable onto Jurassic tilted blocks within Bonnition Basin.
SEQUENCE STRATIGRAPHY AND DEPOSITIONAL ENVIRONMENTS

Raw seismic data

NW-SE Oriented Section – Line 3371

This northern NW-SE section reflects mainly the record of the syn-rift/post rift Cretaceous and Tertiary passive margin infill within the northern Salar region.

Mid Jurassic sedimentation is limited to the northernmost part of the basin with significant turbiditic infill within the grabens.

During the Cretaceous and Tertiary eras, the depositional context is less constrained by tectonic activity, except for a still active transform fault bounding the northern Salar region and the opened proto Atlantic basin.

Contouritic wedges and sediment waves are showing strong bottom current activity since Late Cretaceous and with a probable connection with North Atlantic/ Flemish Pass Basin at this time.
GEOLOGY & GROSS DEPOSITIONAL ENVIRONMENT MAPS: JURASSIC

A set of four (4) Jurassic Gross Depositional Environment (GDE) maps spanning Jurassic sequences were built based on stratigraphic / sedimentological information coupled to seismic data (thickness, structural maps, geomorphological features, and seismic stratigraphy analysis). They represent the alternative paleoenvironmental scenarios at given ages that serve as input to the stratigraphic basin modelling (DionisosFlow™), specifically to constrain the paleobathymetric/paleoenvironmental changes through time and space and the sedimentary pathways. For the Jurassic paleoenvironments, two (2) hypotheses are considered:

1. a rapidly basin drowning in the southeast; and
2. steady shallow paleobathymetry.

FAST DROWNING SCENARIO

SLOW DROWNING SCENARIO
GEOLOGY & GROSS DEPOSITIONAL ENVIRONMENT MAPS: CRETACEOUS

A set of three Cretaceous Gross Depositional Environment (GDE) maps spanning the main sequences were built from the stratigraphic/sedimentological information coupled with the seismic data (thickness, structural maps, geomorphological features, and seismic stratigraphy analysis). They represent the alternative paleoenvironments scenarios at given ages that serve as input to the stratigraphic basin modelling (DionisosFlow™), specifically to constrain the paleobathymetric/paleoenvironmental changes through time and space and the sedimentary pathways.

During Early Cretaceous, the major Avalon Uplift provides a significant clastic sediment input to the remnant Bonnition Basin and the Salar region to the southeast.

During Late Cretaceous, post rift condition prevailed with enhanced thermal subsidence to the southeast and main sediment inputs from the inherited uplifted northwestern region.
GEOLOGY & GROSS DEPOSITIONAL ENVIRONMENT MAPS: PALEogene

A set of three Gross Depositional Environment (GDE) maps spanning the main Paleogene sequences were built from the stratigraphic / sedimentological information coupled with the seismic data (thickness, structural maps, geomorphological features, and seismic stratigraphy analysis).

They represent the paleoenvironments at given ages that serve as input to the stratigraphic basin modelling (DionisosFlow™), specifically to constrain the paleobathymetric/paleoenvironmental changes through time and space and the sedimentary pathways.

During the Paleogene, the main clastic sediment was derived from the inherited uplifted northwestern region. River inputs and eustatic sea level variations mainly controlled the position of the shelf and the main sediment pathways (canyon / channel systems). Inherited rift blocks still locally control the turbiditic systems on the slope.

Since the early Eocene, lowstand fans are intensely reworked by bottom contour currents along the toe of slope, forming giant contouritic wedges and sediment waves.

Sedimentary objects
- Carbonate build up
- Prograding feature / clinoform
- Channel / basin floor fan early phase
- Channel / basin floor fan late phase
- Distal depositional lobe
- Salt diapir
- Volcanics
- Sills

Depositional environments
- Bathyal clastic
- Outer neritic clastic
- Inner neritic clastic
- Coastal / marginal marine
- Carbonaceous inner neretic
- Carbonaceous shallow marine
PETROLEUM PLAY DEFINITION

According to the PRMS definition accepted by the Society of Petroleum Engineers (SPE), a “play or petroleum play” is a model of how a petroleum system (HC charge, reservoir, seal, or trap) may combine to produce petroleum accumulations at a given stratigraphic level (e.g., the Tithonian play). A play may contain prospective resources and reserves (in the economic sense). Six plays have been defined. Two plays display effective reserves in neighboring basins (Jeanne d’Arc, Flemish Pass): Berriasian / Valanginian and Albian-Aptian. Four plays remain hypothetical: Early Jurassic, Middle Jurassic, Kimmeridgian and Late Cretaceous/Paleogene.

<table>
<thead>
<tr>
<th>Plays</th>
<th>Source Rock</th>
<th>Reservoir</th>
<th>Seal</th>
</tr>
</thead>
<tbody>
<tr>
<td>Late Cretaceous</td>
<td>Egret Tithonian</td>
<td>Otter Bay</td>
<td>Dawson Canyon</td>
</tr>
<tr>
<td>/Paleogene</td>
<td></td>
<td>Dawson Canyon</td>
<td></td>
</tr>
<tr>
<td>Albian Aptian</td>
<td>Egret /Tithonian</td>
<td>Ben Nevis</td>
<td>Nautilus</td>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Berriasian/Valanginian</td>
<td>Egret /Tithonian</td>
<td>Hibernia</td>
<td>Whiterose</td>
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<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Kimmeridgian</td>
<td>Egret (lateral eq.)</td>
<td>Voyager</td>
<td>Egret</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mid Jurassic</td>
<td>Sinemurian/Pliensbachian</td>
<td>Iroquois, Downing</td>
<td>Downing</td>
</tr>
<tr>
<td>Early Jurassic</td>
<td>Sinemurian/Pliensbachian</td>
<td>Eurydice</td>
<td>Argo</td>
</tr>
</tbody>
</table>
Within the NL19-CFB01 license area, there are multiple Tertiary fan plays. These Tertiary fans have been imaged over multiple 2D seismic lines within the license area. Many display a Class Ill/IIp AVO response.

North American polarity convention was used in this study. Increase in impedance (positive amplitude) is blue; decrease in impedance (negative amplitude) is orange.

This particular example of a Tertiary fan play, named the Dickinson lead, within the license round area displays a brightening negative amplitude response when viewed in the far angle stack.
Within the NL19-CFB01 license area, there are multiple Cretaceous plays. These have been imaged over multiple 2D seismic lines within the license area. Many display a Class IIn/IIP AVO response.

The North American polarity convention was used in this study. The increase in impedance (positive amplitude) is blue; the decrease in impedance (negative amplitude) is orange.

This particular example of a Cretaceous play, named the Stavanger lead, within the license round area displays a brightening negative amplitude response when viewed in the far angle stack.
FORWARD STRATIGRAPHIC MODELLING: OBJECTIVES AND WORKFLOW

A forward stratigraphic simulation was performed using DionisosFlow™ (an IFPEN software) to (1) understand better the 3D sedimentary architecture of the basin, (2) quantify the sedimentary volumes at the basin scale, and (3) predict the location of prospective areas in regions with less geological information. This modelling was performed from Late Triassic up to Top Eocene. Stratigraphic modelling is an integrated model that takes into account accommodation history, sediment supply (silici-clastic source and carbonate production), and transport processes.

- **Accommodation** reflects the available space creation through time that is defined from subsidence maps and global sea level curve.

- **Sediment Supply** is defined by both silici-clastic source and carbonate production. Silici-clastic sources are defined at the edge of the model and varies through time. It corresponds to river insights. Carbonate production is the in-situ production function of ecological parameters (mainly bathymetry, substratum, wave energy, and fluvial discharge).

- **Transport processes** are macro-scale sediment transport laws (equation of diffusion). These diffusive equations enable the simulation of the sediment distribution based on its content (grain type and density) and local paleobathymetric variations over tens of kilometers.

Sedimentation or erosion is simulated at each point of the basin using mass balance principles, and is then calibrated by tuning all of the environmental parameters (sources, subsidence map, transport/diffusion).

The main steps of workflow for this stratigraphic modelling consisted of:

- Reproducing regionally the overall basin geometry evolution from Late Triassic to Top Cretaceous. This implies (a) a calibration of tectono-stratigraphic sequences with existing structural maps, (b) a reproduction of internal geometries observed on seismic profiles, and (c) a reproduction of lithological trend at well location.

- Predicting and quantifying the sedimentological distribution inside described seismic geobodies away from well calibration and in unexplored areas.

- Extracting refined GDE and lithological 3D volume to be used in the petroleum basin modelling Software (TemisFlow 3D™) and play assessment.

The stratigraphic model extends over 60000 km² (200 x 300km) and spans Base Jurassic (201 Ma) to Top Eocene (34 Ma). Time step resolution is 0.5My, for 334 layers. The spatial resolution is 4km. Model calibration is performed based on 13 structural maps (seismic horizons) and Three (3) wells.
FORWARD STRATIGRAPHIC MODELLING: INPUT PARAMETERS

SILICI-CLASTIC SEDIMENT SUPPLY

Four main sources of sediment have been interpreted to feed this area, based on regional paleo-geo graphic mapping and seismic geomorphological interpretation of objects such as channels, lobes and slope fans. These sources seem relatively steady from the Triassic until the Late Cretaceous originating from the Flemish Cap and largely from the Grand Banks.

![Sediment sources diagram](image)

Sediment sources shed off sediments from existing paleo-highs with intensity varying with tectonic events such as the Late Jurassic rifting and the Avalon uplift.

Volume of sediment (defined as a flux in DionisosFlow™ and sand-shale ratio have first been estimated from thickness maps, then adjusted through the forward simulations. Associated fluvial discharge has been estimated from an average value of about 0.35 mg/l.

EVAPORITES

Hettangian salt layers are identified northwest of the Carson-Bonnition basins within the wells Spoonbill, Cormorant, and Murre and to the southwest with Osprey well. Salt lithologies are intercalated in shales, mudstone and marlstones. Age dating constrains the salt deposition between 215 to 190 Ma.

![Evaporites diagram](image)

That time interval corresponds to a low sea level stage during the Late Triassic to very Early Jurassic in the Global Sea Level curve. This lowstand stage isolates the Carson, Bonnition and Salar basins, thus allowing salt deposition fed from higher frequency (Milankovic) marine incursion.

Salt precipitation in the simulation has been estimated to be around 400m/Myrs.

CARBONATE PRODUCTION

The neighbouring Jeanne d'Arc Basin is largely dominated by silici-clastic sediment but several carbonate levels exist especially during the Jurassic and Early Cretaceous such as the Iroquois and Whale Formations in the Early Jurassic, the Rankin Formation during Oxfordian and some levels in the Early Cretaceous. Well lithology descriptions within the area of interest (St Georges J-55, Skua E-41, Bonnition H-32) highlighted the presence of Late Jurassic and Cretaceous mudstone to marlstone interval from 10 to 100m thick.

![Carbonate Production Rate graph](image)

DionisosFlow™ simulations take into account carbonate production rate as a function of bathymetry, wave energy, substratum nature, and fluvial discharge.

ORGANIC MATTER

The simulation of the organic matter deposition and preservation takes into account

- The primary productivity, in m/Myrs. It is adjusted in order to fit the observed TOC at wells.
- The sedimentation rate
- The possible dilution due to the depositional energy
- The preservation condition at bottom, expressed through an anoxicity coefficient for stagnant or open marine model

The Early and Late Jurassic depocentres may or may not be properly connected with the ocean. Therefore both the stagnant and open marine hypotheses have been tested.

![Open marine vs Stagnant model](image)

After Chiarella and Longhitano 2012
FORWARD STRATIGRAPHIC MODELLING: INPUT PARAMETERS

ESTIMATION OF ERODED THICKNESS DURING AVALON UPLIFT

The study area underwent simultaneous erosion and sedimentation during the regional Avalon unconformity (Late Jurassic-Early Cretaceous). It has been assumed that most of the sedimentation in the eastern Carson and Salar basin (present day deep offshore) resulted from the redeposition of the sediments eroded in the Bonnition and western part of the Carson basin (present day shelf).

The forward sedimentation modelling with DionisosFlow™ consisted of simulating the deposition of sediments prior to the Avalon uplift, followed by their erosion during the uplift.

The Avalon unconformity crosses all the older horizons, from top Basement, Jurassic and Early Cretaceous. The estimation of the eroded thicknesses in the W-NW part of the study area was made through the geomorphological and structural analysis of these horizons.

In addition, the maturity profiles at 7 wells crossing the unconformity can be used to narrow the uncertainty on the eroded thicknesses. At St. Georges J-55, the amount of eroded thickness is lower than the present day thickness above the unconformity. In Skua E-41, the slight shift of maturity data (Ro) at the unconformity depth allows to estimate an eroded thickness around 1500m.

A precise mapping of the Avalon erosion was performed geometrically on 2D seismic, using seven (7) wells as tie points for eroded thickness.

Such uplift appears to be diachronous from south (early phase) to north (late phase) and west to east, starting locally in the Late Jurassic, and active throughout the western region of the study area during the Early Cretaceous.
The geochemical analyses performed in the Carson and Bonnition basin wells have indicated the presence of lean source rocks (TOC ~1%) in the Middle Jurassic (Pliensbachian), and Tithonian. The Kimmeridgian interval has not been encountered in any of the wells in the NL19-CFB01 license area. The Kimmeridgian and Tithonian display much higher TOC content in the neighboring Jeanne d’Arc Basin. There is a regional conjugate equivalent of the Pliensbachian, offshore Portugal, which was in the vicinities of the Carson and Salar basins at that time.

In order to assess the source rock potential within the Study Area, the DionisosFlow™ Forward Stratigraphic Modelling software was used to predict and delineate rich organic matter distribution based on environmental conditions such as bathymetry, substratum nature, and oxygenation conditions. Measured values at well locations (mainly Rock Eval data) were used as a reference to adjust the primary productivity.

Methodology: The volume of organic matter preserved as a facies is converted within DionisosFlow™ into masses of original TOC (oTOC) for comparison with well data and further use in petroleum system modelling. The actual TOC leading to HC generation through cracking corresponds to a fraction (40 – 60%) of the oTOC.

Application to the study area: Two general models are considered for this basin based on its tectonostratigraphic evolution: (1) an anoxic model (stagnant model) that corresponds to the Triassic-Late Jurassic period when the North Atlantic ocean is not very well connected and (2) an open marine model when the North Atlantic ocean is largely open with a connection from the north to the south Atlantic (Page 11).

TOC measurements at well locations (Rock Eval data, Page 31) are used as a reference to calibrate the primary productivity through several scenarios. For both models, primary productivity is estimated around 2.5 m/Myrs. Bathymetry, sedimentation rate, and facies distribution maps (examples below), resulting from the stratigraphic model simulation, constrain organic matter deposition, and the preservation process.

The cross section, presented below, is an extraction of the model showing a vertical distribution of oTOC%. It helps to highlight the stratigraphic position of the richer organic matter layers. The Kimmeridgian and Aptian source rocks are clearly identified as thick and rich. Tithonian source rock potential is present in thin stringers. According to this simulation, the Pliensbachian may present rich organic layers, but there isn’t any well data as evidence to support this.

The maps, presented below, are an extraction of the resulting source rock map for a given source rock stage. It shows both original TOC% distribution (average TOC) and net thickness (TOC above a threshold value) that could be used for petroleum system analysis.
Given the high level of uncertainty on the paleo-environment in the central and eastern part of the studied area (no well penetrated), alternative realistic scenarios of basin subsidence and sedimentation are proposed to provide equiprobably calibrated scenarios of basin infilling (see calibration Page 31). For the Jurassic and Early Cretaceous intervals, the tested uncertain parameters are the paleobathymetry (basin drowning rapidly or slowly) and the carbonate fabric (active or more limited). Late Cretaceous / Tertiary alternative scenarios consider the sand-shale ratio shaded in the model as other parameters are more constrained in the shallow section.
Some calibration results are presented here following the hypotheses as defined in the scenario tree on page 7.

Calibrations are performed on lithologies at the three (3) wells simultaneously (scenario a to f). The dominant lithology is here represented per cell of the model. They all provide an appropriate match. The six (6) models are considered calibrated and represent possible equiprobable end members.

Calibrations are also performed on simulated original TOC (%TOC) content accounting for its deposition and preservation (see page 29).

Good match (absolute values and trends) exists in some time units. Two scenarios not sufficiently honoring the data are discarded. Matching scenarios were used to define a sound source rock model.

All calibrated scenarios at well are providing a wide range of TOC richness and effective thickness in areas away from well control (Salar region).

Following basin modelling, simulations are taking into account all the matching endmember scenarios to propose an alternative vision in terms of petroleum system behavior.
FORWARD STRATIGRAPHIC SIMULATION: STRUCTURAL CALIBRATION

The calibration phase consisted in testing various scenarios to calibrate both geometry/thickness maps and respect lithologies recorded at well locations. The main input parameters used for calibration are source location, fluxes, sand/shale/carbonate/organic matter ratio, erosion and timing.

Sample maps here below compare interpreted thickness maps (between picked seismic horizons) and simulated sediment thickness. All the alternative models show a good consistency.
The grid below (1) illustrates the simulated stratigraphic model with lithology properties (or dominant lithology). For each layer, a set of more than 15 output properties can be extracted. They include paleoenvironment conditions (2a), such as bathymetry, water flow, and wave energy; and lithologies (2b) such as sand, shale, mudstone, carbonate, evaporites, and organic matter.

1- 3D Stratigraphic Model Grid

To give a more representative mapping of actual stratigraphic sequences, groups of layers corresponding to two to four million years are selected. The depositional environment maps (3) and the lithology distribution maps (4) are built by combining the previous properties for each sequence.
FORWARD STRATIGRAPHIC MODELLING:
LITHOLOGY AND DEPOSITIONAL ENVIRONMENTS
MODELLING

Environmental parameters, such as the paleobathymetries and the lithological content, are used to define the paleoenvironments.
RESERVOIR DISTRIBUTION ALTERNATIVE SCENARIOS

Net sandstone thickness varies per scenario depending essentially on the basin drowning rate and the carbonate factory being more or less productive. One sample layer is given for three key time horizons with some alternative equiprobable scenarios, all calibrating in terms of thickness (at well marker and to the seismic isopach) and the lithologies at wells (see Page 31).

- **Paleogene**
  - One sample layer
  - Sand rich scenario
  - Sand limited scenario

- **Early Cretaceous**
  - One sample layer
  - Fast drowning scenario without carbonate
  - Slow drowning scenario without carbonate
  - Slow drowning scenario with carbonate

- **Jurassic**
  - One sample layer
  - Fast drowning scenario without carbonate
  - Slow drowning scenario without carbonate
  - Slow drowning scenario with carbonate

Scenario Tree:
- **Late K / Tertiary**
  - Slow drowning basins
  - Active carbonate factory
  - Limited carbonate factory
  - Mid Jurassic / Early K
  - Sand limited
  - Sand rich
  - Slow drowning basins

Net Thickness Sandstone Layer
- 0
- 100 km
- Low
- High
The Wheeler diagram reflects the paleo environment setting as a function of geological time. The environments within the Triassic and Middle Jurassic change from evaporitic / shallow marine depocenter toward the western basins to potential carbonate and marine clastic conditions on the eastern basin edges.

The main Late Jurassic deposits are dominantly shaly with significant organic fraction. Early / mid Cretaceous reservoirs are located to the east of the studied area and they are considered as the product of erosion of the western edge of the basin (Avalon erosion).

Post rift to passive sedimentation prevailed during late Cretaceous and Cenozoic with progressive drowning of the eastern region, and alternate detrital shale and sandy turbidite.
FROM SEDIMENTOLOGY / STRATIGRAPHY TO MODELLING

Initial Seismic and Stratigraphic Interpretation
(Seismic interpretation & GDE mapping)

3D Forward Stratigraphic Model
(sand proportion over 330 layers; 4x4 km grid)

3D Forward Stratigraphic Model
Lithofacies Distribution

3D Petroleum System Model
(41 upscaled layers in 1x1km grid)
PETROLEUM SYSTEM MODELLING

The basin and petroleum system modelling used the present day information (geometry, facies, and source rock properties) and the conceptual basin evolution (sequence stratigraphic analysis, and mainly paleo-environment and basin tectonic evolution) to reproduce the physical, thermal, and chemical processes that occurred during its deposition.

The generation, expulsion, migration, and entrapment of hydrocarbons from the source rock to the reservoirs were simulated, taking into account both the paleo-geometry, the thermal state, fluid flow, and the rock’s petrophysical properties.

**1D modelling**: A first understanding of the geothermal context and pressure field was rapidly assessed by a series of 1D models at key well locations, helping to evaluate oil and gas generation timing in the various source rock candidates.

**3D Model construction**: The 3D static petroleum system model was built using TemisFlow™ with the structural depth maps used to create the present day model geometry with additional subdivisions from DionisosFlow™. The 3D stratigraphic cube with lithological and source rock distribution maps was populated using gross lithofacies maps extracted from the DionisosFlow™ results.

**2D Basin Modelling Calibration**: Two 2D sections were extracted from the 3D framework to perform the calibration of the thermal and pressure regimes. The sections were chosen for their representativeness of the petroleum system (passing through the source rock kitchen) and to include key wells with relevant data for calibration. The model boundary conditions through time were defined. This enabled the thermal calibration of the model for both historical and present day temperature. The model properties, especially the fine tuning of facies distribution and permeability parameters, were taken into account for pressure calibration.

**3D Hydrocarbon migration calibration**: The hydrocarbon generation and migration simulation was performed using Full Darcy Compositional Migration in TemisFlow™ and taking into account the results of 2D modelling. Source rock type and richness were also defined in the model. The known oil and gas accumulations and shows (including sea bottom seeps) and their properties were used to calibrate the model and understand its limitations.

The model uses a compositional description of the HC (dry gas, wet gas, condensate, light oil, intermediate, and heavy oil). The HC chemical composition depends on the kerogen compositional kinetics and HC product cracking.

The hydrocarbon saturation within the source rock during HC generation generates an increase of the source rock capillary pressure, and consequently, the expulsion of hydrocarbons. The model assumes that a minimal saturation is needed to trigger the expulsion.

The evaluation of charge within main plays was calculated by taking into account the physical processes governing the migration of hydrocarbon fluids.

The HC fluid flow is computed through the multiphase Darcy Law flow. It simulates the pressure regime (HC pressure and water pressure), capillary forces retention effect, and buoyancy forces.

The models assume that a minimal saturation within the HC migration pathways (carrier beds, faults conduits) is needed to proceed. No movement occurs until the HC saturation reaches the minimal residual saturation. Consequently, the long distance HC migration models predict a lower migration efficiency towards the traps.

The models also offer the option of instantaneous HC migration toward the traps (Trap Charge Assessment [TCA] module). The TCA module is used as a complement to the Darcy modelling since it allows for a higher horizontal resolution of the model.
The initial 3D petroleum system model (13 seismic stratigraphic layers, arrows) has been subdivided into 41 layers, enabling the identification of the main components of the petroleum system, while preserving the main regional lithological and sequence stratigraphic events.

To create this petroleum system model (shown below), the 3D stratigraphic model (DionisosFlow™) was then upscaled from 330 to 32 layers for the interval between Base Jurassic and C34 (Top Paleogene) while maintaining the regional geological context and keeping the highest degree of information.

### 3D BLOCK BUILDING

<table>
<thead>
<tr>
<th>Age (Ma)</th>
<th>Layer</th>
<th>PETROLEUM SYSTEM</th>
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<tbody>
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<td>11.3</td>
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<td>Intra Toarcian</td>
<td></td>
</tr>
<tr>
<td>176</td>
<td>Intra Toarcian</td>
<td></td>
</tr>
<tr>
<td>185</td>
<td>J185</td>
<td></td>
</tr>
<tr>
<td>188</td>
<td>Intra Pliensbachian</td>
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<tr>
<td>190.5</td>
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<tr>
<td>191</td>
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<td>J201</td>
<td></td>
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<tr>
<td>251</td>
<td>Base Mesozoic</td>
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</tbody>
</table>

### 3D (fence diagram) stratigraphic view considering the final block layering

**Dominant petroleum system element**
- Source rock
- Seal
- Reservoir
- Seismic horizons
- Simulated in forward stratigraphic model
VITRINITE REFLECTANCE DATA

The Vitrinite Reflectance data are displayed on the graph at left for seven (7) wells, which are of different vintages and from multiple geochemical laboratories. A wide range of values may be found for a given burial depth and a given well while maturity trends with depth are quite similar between wells and/or laboratories.

The wells Osprey, Spoonbill and Murre show Ro values which indicate an early oil generation window at shallow depth (< 1200m). These values are taken below the Avalon unconformity in the Jurassic. They result in an early burial down to 3000 m or more, with a subsequent increase of maturity followed by an uplift.

The global Ro trends in the Cretaceous and older sediments suggest the geothermal gradient was somewhat higher than present day at maximum burial before the Avalon uplift. The ODP well (Leg 210, Hole 1276), which is close to the study area in the deep basin oceanic crust setting, also indicates an early oil generation at shallow burial depths. Here, maturity depends mainly on high thermal gradients at low burial depths due to the shallow lithosphere asthenosphere boundary (LAB).

The above observations are used to calibrate the paleo-thermal regime of the 3D basin model.

TEMPERATURE DATA

The bottom hole temperature data from the Carson basin shelf wells indicate relatively low average deep thermal gradients in a range of 22 to 30 °C/km with an average of 27 °C/km.

The heat flow measurements of the slope and deepwater basins indicate shallow surface heat flow in accordance with relatively low deep thermal gradient in the shelf wells.

The above observations are used to calibrate the thermal regime of the 3D basin model at present day.
SOURCE ROCK DEFINITION: SYNTHEZI

Four known, hypothetical or speculative, source rocks have been modeled with DionisosFlow™ for further use in the petroleum system modelling of the Carson, Bonnition, and Salar basins:

1. The Sinemurian and Pliensbachian calcareous shale and claystone (post early rift) in an epeiric marine setting has no clear potential. However, speculative potential is supported by the sedimentary model and evidence of a widespread anoxic event at that time. The organic matter distribution will be mostly driven by the distribution of deeper environments during the rift type subsidence (Sinemurian and Pliensbachian). There is also a known source rock of this age on the conjugate margin.

2. Kimmeridgian source rock has not been encountered at well in the study area. However, its potential presence would be considered as lateral equivalent of the Egret Fm. in the Jeanne d’Arc Basin. According to the organic matter deposition model, the TOC may reach high values (> 3%) in the Carson and Salar depocentres.

3. The Tithonian source rock, present in shelf wells in the area, displays shales (TOC ~1%) and marine Type II organic matter.

4. The Aptian source rock, which develops during the drowning of the Carson, Bonnition and Salar basins, in the northern part of the Study Area, has high potential (TOC >5%) as demonstrated at the ODP well 1276 to the east, over the oceanic crust.

5. Cenomanian/Turonian and Paleocene organic rich intervals are also proven in the neighbouring ODP well, but are not considered in the model because they are completely immature within the study area according to thermal modelling results.

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**Table: Source Rock Model Definition (reference model)**

<table>
<thead>
<tr>
<th>Source Rock</th>
<th>Level of Certainty</th>
<th>Kerogen Type</th>
<th>Depositional Environment</th>
<th>Organofacies classification</th>
<th>Distribution</th>
<th>SPI* (t/m²)</th>
<th>Average in depocentres</th>
</tr>
</thead>
<tbody>
<tr>
<td>Aptian</td>
<td>Known SR</td>
<td>Type II</td>
<td>Epeiric system</td>
<td>E4/E5</td>
<td>Regional open marine</td>
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<td>6</td>
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<tr>
<td>Tithonian</td>
<td>Known SR</td>
<td>Type II</td>
<td>Rift system: Outer neritic to bathyal</td>
<td>R4</td>
<td>Regional restricted marine</td>
<td>1</td>
<td>4</td>
</tr>
<tr>
<td>Kimmeridgian/Egret</td>
<td>Known SR</td>
<td>Type II</td>
<td>Rift system: Outer neritic to bathyal</td>
<td>R4</td>
<td>Regional restricted marine</td>
<td>2</td>
<td>6</td>
</tr>
<tr>
<td>Pliensbachian/Sinemurian</td>
<td>Hypothetical SR</td>
<td>Type II</td>
<td>Rift system: Inner to outer neritic</td>
<td>R3/R4</td>
<td>Regional restricted marine</td>
<td>0.5</td>
<td>6</td>
</tr>
</tbody>
</table>

---

**Depositional Organofacies Classification**

- Continental / lacustrine
- Facies / Paleoenvironment
- Marginal / restricted to very shallow marine
- Sand-prone environment
- Mud-prone shallow marine
- Mud-prone shelf marine to slope
- Slope / basin fan sand
- Basin mud
- Shallow marine carbonate
- Mud-prone restricted or open marine carbonate
- No-deposition

**Organic Matter Type**

- Coal
- Lacustrine Type I source rock
- Terrestrial Type III source rock
- Mix restricted marine/continental Type I/III source rock
- Mix marine/continental Type I/III source rock
- Restricted marine Type II to Type III with diagenic smears
- Marine source rock Type II
- Carbonate marine source rock Type A

* SPI: Source Rock Potential Index (Ton/m²)

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From Beicip-Franlab report 2017
The heat flow evolution in the Carson, Bonnition and Salar basins results from the successive Late Triassic and Jurassic rifting phases leading to the Early Cretaceous oceanic spreading to the east, and further lithosphere cooling, up to present day. The thermal model takes into account the heat transfer through evolving, thinning continental crust and the synchronous deposition of sediments. The resulting heat flow varies through time and location in the basin and is controlled by the following factors:

- Thickness and type of crust leading to radiogenic heat production of continental crust
- Depth of the Lithosphere-Asthenosphere Boundary LAB (isotherm 1333 °C)
- Heat advection rate across the LAB and conductive heat transfer across the lithosphere up to the top of sediments
- Sedimentation rate
- Bulk thermal conductivity of sediments controlled by compaction and type of lithology
- Radiogenic heat production of sediments.

The heat advection rate during rifting is handled through an implicit 3D lithospheric model thinning factor of the continental crust calculated from an assumed pre-Triassic thickness of 35 km. The continental rifting also accounts for the uplift of the LAB (1333 °C). The oceanization is simulated through the thinning of the lithosphere (shallow LAB) at the location of the Early Cretaceous spreading axis. Present-day LAB depth varies from 120 km in the west and shallowing to 80 km basinwards towards the oceanic crust domain (Goutorbe et al., 2011).

Polyphased rifting took place between Late Triassic up to late Early Cretaceous. Total thinning is thus distributed into three main rifting phases: 1) Triassic to Early Jurassic, 2) Late Jurassic, and 3) Early Cretaceous. This is shown in the figure above where an intermediate crustal thickness is recalculated.

The resulting simulated lithospheric heat flow migrates laterally, related to the different phases of polyphased rifting, attaining the highest values at the end of each rift. The crustal thinning during Jurassic up to Early Cretaceous results in an increase of temperature in the crust and the sediments, leading to higher geothermal gradients and heat flow. Since late Early Cretaceous post-rift phase, the heat flow decreases progressively until equilibrium is reached. In addition, a high Cenozoic sedimentation rate over the depocentres contributes to the overall decrease of the heat flow. Uncertainty of simulated heat flow mainly depends on the depth of the Lithosphere-Asthenosphere Boundary (LAB) during geological time, therefore a low, best, and high case scenarios were established.
The thermal modelling accounts for the heat-flow increase during the various Jurassic/Early Cretaceous rifting phases, as well as for the crustal facies changes from continental transitional to oceanic crust.

The average temperature gradient decreases between the rifted continental crust toward the oceanic crust at present day.

The salt diapirs toward the shelf have some impact on the local geothermal gradients, as they concentrate the heat flow lines because of their higher thermal conductivity. However, the final impact on the temperature isotherms remains virtually undetectable.

The sediments over the oceanic crust remain marginally mature.

Most of the source rock levels (red lines) remain in the oil to late oil window (in the thickest depocentres). The Cretaceous sedimentary interval is found at the lower maturity interval, along this cross section, so early migrated oil and late gas could coexist.
VITRINIT Ro (%) - AT PRESENT DAY FOR SELECTED SOURCE ROCKS LEVEL

The present-day source rock maturity, expressed in Equivalent Vitrinite Reflectance (VRo%), shows Middle Jurassic source rocks within the oil and light oil condensate window over most of the depocentres within the study area.

When present, the Kimmeridgian source shows a similar maturity pattern

The Tithonian source rock remains in the oil window over the entire study area.

The Aptian source rock remains marginally mature over the study area and is therefore unlikely to contribute significantly to the petroleum system.

SENSITIVITY

The uncertainty on the thermal regime during the Jurassic rifting only affects the Early Jurassic source rock. The Late Jurassic and Cretaceous maturities are not affected as they mature only during the Late Cretaceous Tertiary cooling stage.
Maturity expressed in Vitrine Reflectance was calculated for the Middle Jurassic source rock layer through geological time. The oil window (VRo% > 0.6) is reached during the Early Cretaceous in the deepest part of the depocentres. The oil window (0.6 – 1.1 VRo%) is crossed in almost all the basin area at the end of the latest Cretaceous. With the exception of the deepest depocentres, which have reached most of their maturity before the end of the Cretaceous, the Middle Jurassic source-rock maturity occurs during the Tertiary, up to present day.
Maturity expressed in Vitrine Reflectance was calculated for the Kimmeridgian source rock layer through geological time. The oil window (0.6 – 1.1 VRo%) is crossed in the deepest depocenter of the basin during the Cretaceous. The Kimmeridgian source rock maturity occurs during the Tertiary, up to present day.
VITRINITE Ro (%) EVOLUTION THROUGH TIME: TITHONIAN

Maturity expressed in Vitrine Reflectance was calculated for the Tithonian source rock layer through geological time. The oil window (0.6 – 1.1 VRo%) is crossed in the deepest depocenter of the basin during the Cretaceous. The Tithonian source rock maturity occurs during the Tertiary, up to present day.
Maturity expressed in Vitrine Reflectance was calculated for the Late Aptian source rock layer through geological time. The Aptian source rock remains immature until Miocene time and reaches marginally maturity at present day.
The pressure regime is mainly hydrostatic over the entire area, as shown on the representative computed pressure section extraction. The low to moderate sedimentation rates and the presence of semi-permeable deposits in the Jurassic depocentres prevent under compaction phenomena, leading to slight overpressures in deep basins.
HC GENERATION HISTORY

In the deeply buried depocentres on the slope to the west, the kerogen Transformation Ratio of the Middle Jurassic source rock reaches near 100% during the Early Cretaceous. The Kimmeridgian reaches 90% and matures mostly during the Early to Late Cretaceous, while the Tithonian matures during the Tertiary. In the depocentres of the deep offshore, there is a progressive maturity increase due to the slow burial rate since the Cretaceous for the Middle Jurassic up to 90% and since the late Tertiary for the Aptian source rock, which reaches less than 20% TR.
HYDROCARBON SATURATION

Migration modelling suggests the preferred migration pathways are toward the traps. The migration pathways include a lateral component along 10-20 km distance from the active depocentres toward the structural highs, usually associated with the crests of a Jurassic-tilted block.

At the top of the tilted block crests, the buoyancy forces may overcome the capillary resistance of the seals, and a further charge can occur toward shallower reservoir (Cretaceous and Tertiary).

The hydrocarbons (HC) are mostly liquid, as they originate from the active kitchens which are mostly within the oil window.

TIMING OF MATURATION

The timing of hydrocarbon maturation, illustrated by the age at which the main source rock levels in the study area reach 0.8%Ro (equivalent to the top of oil generation for a Type II kerogen), can be in competition with the erosion related to the Avalon Uplift.

The Late Jurassic source rock reaches the top oil window maturity mostly after the Cretaceous.

Some Early Jurassic depocentres may reach the oil window at the end of the Jurassic in limited areas corresponding to the eroded part on the shelf. Some HC potential may be lost as a consequence of the early generation.

The Early Jurassic source rocks in the deep offshore, if present, reach the top oil window during Cretaceous or Paleogene.
The 3D reference petroleum system model is built on the basis of a calibrated lithofacies geocube, derived from stratigraphic modelling. The sand-shale ratios and depositional environment facies obtained by the stratigraphic modelling have been used to define the main elements of the petroleum system in Carson, Bonnition and Salar basins:

- **Reservoirs** correspond to stacked sedimentary layers with more than 50% sand content, and shelf-slope and turbiditic facies or high energy carbonate.
- **Carrier beds** correspond to stacked sedimentary layers with 30 to 50% sand content and expected, long lateral continuity (turbidites).
- **Overburden** corresponds to silty or marly facies with some sand content (up to 30%).
- **Seals** correspond to stacked shaly facies (more than 80% shale content). Source rocks are organic matter-rich shales.

The 3D view shows the Kimmeridgian horizon and its maturity displayed as a background map in vitrinite reflectance equivalent. It shows the slope lines along the Kimmeridgian horizon, with the depocentres acting as kitchens and the distribution of traps (in blue/violet) associated with the main plays. These traps can be potentially charged according to the HC migration modelling in certain HC migration modelling scenarios. The lack of significant traps with potential charge on the shelf results from the limited extension of active kitchens and the erosion of main reservoirs during the Avalon Uplift. Please note that in some cases, where surfaces converge, the older surface is replaced by a younger surface and the thickness between these two surfaces becomes zero. For modelling purposes, all surfaces have been mapped to the extent of the modelled region.
UNCERTAINTY IN HYDROCARBON MIGRATION AND CHARGE

Source Controlled HC Migration

High SR Potential
Slow Drowning Anoxic Scenario

Low SR Potential
Slow Drowning Anoxic Scenario

Trap not filled to spill point
Fill spill leakage
High seal efficiency

Seal Controlled HC Migration

Low Seal Efficiency
Sealed Leakage
HC Lost

High Seal Efficiency

High SR Potential
Slow Drowning Anoxic Scenario

High SR Potential
Slow Drowning Anoxic Scenario

Trap not filled to spill point
Top seal leakage
Low Top capillary pressure
High SR potential

Trap Charge Assessment

Scenario A

Scenario B

Sensitivity analysis for 3D hydrocarbon migration modelling was taken in consideration to determine the main uncertain parameters for hydrocarbon charge and therefore unrisked volumes in place estimation. Two main uncertain parameters were considered:

• Initial Source Rock Potential: given by the different estimates on oTOC between the forward stratigraphic models. The impact of hydrocarbon migration with source rock potential (source-controlled HC migration).

• Seal Efficiency: given by the top capillary pressure calculated during HC migration Darcy simulations.

Scenario A and B, illustrated in the 3D view, correspond to a mixture between a source-controlled HC migration and a seal-controlled HC migration. Both scenarios will give as a result different HC charge models with different vertical and horizontal volumes in place.

The HC volume estimates (low, best and high) will be derived from the individual results of each outcome attached to a given scenario.
UNRISKED VOLUMES FOR NL19-CFB01
Volumes Contained In The 9 Parcels (1 To 9)

The distribution of unrisked volumes of hydrocarbons corresponds to the amount of oil (in Bbbl), gas (Tcf), and oil+gas (in Bboe) that can be present in the plays according to the equiprobable and calibrated petroleum system scenarios (see page 7).

The volumes described here are aggregate, summed volumes for the nine license blocks only. Volumes within the study area but outside the license blocks are not considered.

### Oil Unrisked Volumes in place (Bbbl)

<table>
<thead>
<tr>
<th></th>
<th>Jurassic</th>
<th>Cretaceous</th>
<th>Tertiary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Middle Jurassic</td>
<td>Kimmeridgian</td>
<td>Valanginian</td>
</tr>
<tr>
<td>P90 Low scenario</td>
<td>0.04</td>
<td>0.02</td>
<td>0.81</td>
</tr>
<tr>
<td>P50 Most likely scenario</td>
<td>0.10</td>
<td>0.03</td>
<td>1.35</td>
</tr>
<tr>
<td>P10 High scenario</td>
<td>0.37</td>
<td>0.29</td>
<td>2.85</td>
</tr>
</tbody>
</table>

### Gas Unrisked Volumes in place (Tcf)

<table>
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<th>Cretaceous</th>
<th>Tertiary</th>
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<td>P90 Low scenario</td>
<td>0.11</td>
<td>0.04</td>
<td>1.65</td>
</tr>
<tr>
<td>P50 Most likely scenario</td>
<td>0.25</td>
<td>0.06</td>
<td>2.88</td>
</tr>
<tr>
<td>P10 High scenario</td>
<td>1.20</td>
<td>0.68</td>
<td>6.73</td>
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### Oil Equivalent

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<td>P90 Low scenario</td>
<td>0.06</td>
<td>0.03</td>
<td>1.10</td>
</tr>
<tr>
<td>P50 Most likely scenario</td>
<td>0.14</td>
<td>0.04</td>
<td>1.86</td>
</tr>
<tr>
<td>P10 High scenario</td>
<td>0.58</td>
<td>0.41</td>
<td>4.05</td>
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</table>

### Oil Unrisked Volumes in place (Bboe)

<table>
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<th>Cretaceous</th>
<th>Tertiary</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Middle Jurassic</td>
<td>Kimmeridgian</td>
<td>Valanginian</td>
</tr>
<tr>
<td>P90 Low scenario</td>
<td>0.04</td>
<td>0.02</td>
<td>0.81</td>
</tr>
<tr>
<td>P50 Most likely scenario</td>
<td>0.10</td>
<td>0.03</td>
<td>1.35</td>
</tr>
<tr>
<td>P10 High scenario</td>
<td>0.37</td>
<td>0.29</td>
<td>2.85</td>
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### Gas Unrisked Volumes in place (Tcf)

<table>
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<tr>
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<td>P10 High scenario</td>
<td>1.20</td>
<td>0.68</td>
<td>6.73</td>
</tr>
</tbody>
</table>
The unrisked volumes are presented as high, most likely, and low cases according to the various calibrated petroleum system scenarios. They have been computed from the outcome of 11 calibrated runs corresponding to:
- Low, medium, high cutoff on HC concentrations (kg/m²) in reservoir cells
- Slow drowning anoxic scenarios
- Fast drowning oxic scenarios

The obtained unrisked volume distribution corresponds to a near lognormal pattern. The volumes described here are aggregate, summed volumes for the nine parcels.
The Global Play Grade is evaluated from the following components:

1. The grade (1 to 5) of known plays (stratigraphic) as defined by the size of discoveries and petroleum system efficiency, known from available worldwide basin screening studies.
2. The probability of geological success is separated into four main independent terms:
   - \( \text{Phc} \): HC charge (source rock presence and HC expulsion/migration efficiency)
   - \( \text{Ps} \): Seal presence and efficiency (thickness/continuity/capillary resistance)
   - \( \text{Pr} \): Reservoir presence and quality (Porous thickness, permeability range)
   - \( \text{Pt} \): Trap existence (in the case of regional 2D seismic grid and interpretation)
3. Leads and prospects may be mutually dependent. For each dependent lead, the POS in the case of success or failure will be higher or lower respectively compared to the independent POS.

The POS is attached to an unrisked volume (usually PIIP in MMBoe best estimate).

### RISK EVALUATION AND POS

The risk analysis corresponds to semi-quantitative thresholds on the POS of the petroleum system components applicable over the studied area.

The HC charge risk was defined by average amount of charge HC/km² (e.g., > 500 kg/m²) in the reservoir play toward and up to the traps. It is directly related to the presence of an active source rock in the drainage area of the traps.

The reservoir risk was defined by the threshold on estimated net thickness and individual sand layer thickness (Total > 100 m, 1 individual sand layer > 5 m).

The seal risk was defined by the threshold on the seal thickness and continuity (faulted and <10m, unfaulted and >50m).

The trap risk was defined by trap volume threshold and fill spill analysis (number of traps with Gross Rock volumes (GRV) > 100, 500 or 1000 million m³ resulting from the fill spill analysis). In the fill-spill analysis, the excess charge of individual traps filled up to spill point may charge a trap updip. In this case, the individual traps may be merged into a single larger trap.

Risk maps of the individual petroleum system components are known as Common Risk Segment (CRS) maps.

The global exploration risk for the play is defined as a Composite Common Risk Segment (CCRS) map and is obtained by superimposing the individual CRS maps.

CCRS multiplay maps may also be built to evaluate the global exploration risk.

### RISK SCALE – CHANCE OF SUCCESS

The risk scale can be qualitative (low – medium – high) or quantitative (1 low probability to 5 highest probability). Grade and Probability can be associated as shown.
Common Risk Segment (CRS) mapping was performed, based on the reservoir and seal elements, and it considered their presence and efficiencies. Using the full resolution, forward modelling stratigraphic 3D grid (of which one play example is presented here), the CRS maps took into account elements such as net sands and net shales and the thickness of vertically continuous beds.

For example, the low risk reservoir areas are characterized by net sand thicker than 100m with at least one vertically continuous bed > 20m. A good seal is characterized by at least 20m of continuous shales. The risks are classified as low, medium or high.

The HC charge risk map was derived from the computed HC charge within a given play through petroleum system modelling (HC volumes present in traps - structural and/or stratigraphic).

The HC charge risk has been evaluated in the Beicip-Franlab Internal Nalcor/DNR report and is not shown here. A random example is presented here.

For each play, HC Composite Common Risk Segment (CCRS) maps were obtained by combining the HC charge (expulsion and migration) with the geological CRS maps. These CCRS maps express the relative exploration risk throughout the acreage for a given play (Beicip-Franlab Internal Nalcor/DNR report).
INDIVIDUAL PROSPECT/LEAD POS
For a given lead containing significant HC volumes (in the order of 0.3 Bboe best estimate per lead), the average probability of success (individual Probability of Success [POS]) may vary from 5% to 25% depending on the stratigraphic play (Early Jurassic, Late Jurassic, Cretaceous, or Tertiary) and the trap type (faulted blocks, stratigraphic, etc.). The POS estimates are derived from the play component risk maps, and structural geophysical evidence.

GLOBAL PROBABILITY OF GEOLOGICAL SUCCESS for the NL19-CFB01
The Global Probability of Success POGS curve quantifies the chances of success to find at least a given HC volume in the exploration blocks of NL19-CFB01 as a whole.

The Global Play grade estimate is 60% (as defined on Page 56).

The exploration status is approximately one (1) wells/7500 km² on the shelf, and exploration success is low (no discovery).

The estimated POGS to find the P50 estimate (4.0 Bboe) is 11% and is consistent with the POGS estimate from the exploration potential and play grade as well as from the risked volumes weighted by play grade.

The POGS risk curve characterizes a medium to high risk exploration area.

EVOLVING POGS WITH ADDITIONAL DATA
The POGS is directly dependent on the amount and quality of data. 3D seismic and new well information may significantly change the POGS estimates.
A synthetic petroleum chart illustrating the petroleum components and timing of the generation, expulsion, migration, and entrapment of hydrocarbon is proposed:

- The Early and Middle Jurassic are generating oil since the Cretaceous up to the Tertiary, where they can reach locally the gas window in the deepest depocentres.
- The main source rocks (Kimmeridgian and Tithonian) are generating oil during the Tertiary and are starting to expel oil a few million years later.
- The Aptian source rock reaches only the incipient oil generation zone.

The Carson-Bonnition-Salar basins are therefore a potential oil province. The main reservoirs are deposited during active tectonic phases (riifting or uplift). In most cases, the HC charge occurs after the reservoir deposition and the trap formation. The highest potential is to be expected in the Early Cretaceous sandstone reservoirs, which are properly deposited just above the potentially most prolific source rocks.
REFERENCES


Stein, C.L., Carter, J.C., Norris, D.N., and Cameron, D.C. 2017. BSR Distribution from newly acquired 2D Seismic and the potential link to thermogenic petroleum systems, Offshore NL, Canada. 79th EAGE Conference.


