Introduction

The underexplored Carson, Bonnition and Salar basins appear prospective for oil and gas, after newly acquired regional 2D seismic data shows evidence of leads that have been tested using data-calibrated, equiprobable alternative petroleum system models. The objective of the petroleum system assessment was to provide petroleum resource estimates for the area through seismic structural and stratigraphic interpretation, and 2D/3D basin modelling for play risk analysis and volume estimates of hydrocarbon (HC) accumulation. Basin modeling was set up in order to account for alternative realistic (geologically possible) models. Such a multi-scenario approach was designed to account for some parameters that contained inherent uncertainty due to the limited data available in this frontier region.

Methodology

The Petroleum System Assessment workflow included:

- Regional tectonic setting definition accounting for the complex rifting, subsidence and uplift events; analysis of the Gross Depositional Environment and reservoir characteristics combining sedimentology, sequence and seismic stratigraphy;
- Forward stratigraphic modelling; thermal regime and source-rock assessment;
- 3D integrated petroleum system modelling of oil and gas migration; entrapment and unrisked HC volume assessment.

Several stratigraphic and petroleum system models were constructed and calibrated to available data (well and seismic) to account for less constrained parameters (Figure 2) such as: 1) the geodynamic
evolution of the basin and especially the basement drowning timing 2) the lithological content particularly in most remote parts of the basin, away from well constraints. 3) the carbonate factory production efficiency and 4) the source rock deposition and preservation potential.

All proposed scenarios had 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 feature and HC occurrence forecasts. Ultimately the resource assessment was accounting for 11 fully calibrated geologically realistic end-member models, all honoring all available data.

**Geodynamic evolution**

The northeast edge of the Newfoundland margin was subject to a complex rifting history (Figure 3). The Carson, Bonnition and Salar basins experienced successive rift episodes associated with the northward opening of the North Atlantic Ocean since Late Triassic times.

The rifting history can be described in two main phases: Late Triassic to Late Jurassic and Late Jurassic to Early Cretaceous. A third phase corresponding to the separation between Newfoundland and Irish margins seems to have minor impact on Carson, Bonnition and Salar basins. The first phase is characterized by crustal stretching whereas thinning and exhumation of the lithospheric mantle occurred during the second phase.

**Sedimentological evolution**

Thick Jurassic syn-rift continental to marginal marine sediments were deposited within the Carson, Bonnition and Salar basins. Those sediments are significantly eroded during the Avalon uplift in the proximal shelf areas.

Cretaceous fluvial plain to marine deposits in the Salar Basin record the initial reworking of northern older Jurassic sediments eroded during an uplift event of the shelf area to the west (Late Jurassic to Early Cretaceous) and is overlain by Albian post-rift shales. Aptian canyon pathways recording this high energy depositional event are coeval with lowstand lobes in the Salar area.

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**Figure 3** Wheeler diagrams of the study area with schematic subsidence model.
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.

**Forward stratigraphic modelling**

Geological interpretations and incertitude were used as input for several forward stratigraphic models performed with the DionisosFlow™ software. Given the high level of uncertainty on the paleoenvironment in the central and eastern part of the studied area (no well penetrated), alternative realistic scenarios of basin subsidence and sedimentation were proposed to provide equiprobably calibrated scenarios of basin infilling (Figure 2). For the Jurassic and Early Cretaceous intervals, the tested uncertain parameters were the paleobathymetry (basin drowning rapidly or slowly) and the carbonate fabric (active or more limited). Late Cretaceous / Cenozoic alternative scenarios considered the sand-shale ratio variation in the model as other parameters were more constrained in the shallow section.

![Initial Seismic and Stratigraphic Interpretation](image1)

![3D Forward Stratigraphic Models](image2)

![3D Petroleum System Models](image3)

![Resource Assessment](image4)

**Figure 4** From seismic stratigraphic interpretation to lithofacies and petroleum system modelling.

All models provided a high vertical resolution (meter scale, 0.5 Myr time step for 334 layers) of the sand / shale / carbonate / original total organic carbon (TOC) distribution and depositional facies throughout the area of over 60000 km² (200 x 300km). These results were calibrated on the available well data, seismic sequences and thickness maps in the various plays.

These alternate models were used to map the extension of reservoirs, carrier beds and seals, as well as the reservoir quality (individual pay zone thicknesses and depositional energy), seal efficiency and candidate source-rocks extension through simulation of deposition and preservation of TOC content during burial (for each different lithological alternative model).

**Petroleum system modelling**

Integrated 3D models were built using TemisFlow™ based on lithological end members provided by the different forward stratigraphic models. All models are calibrated in terms of thermal and fluid flow regime temperature, maturity and pressure (Figure 4). Distribution and observed fluid properties were
compared with hydrocarbon occurrence detection such as gas chimneys and amplitude versus offset (AVO) response, to constrain the geological models. Sensitivity analysis for 3D hydrocarbon migration modelling was taken into 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 (original TOC) between the forward stratigraphic models (source-controlled HC migration).
- Seal Efficiency: given by the top capillary pressure calculated during HC Darcy migration.

The HC volume estimates (low, best and high) were derived from the individual results of each outcome attached to a given alternative scenario with different HC charge (Figure 4).

**Conclusions**

The Early and Middle Jurassic are generating oil since the Cretaceous up to the Cenozoic, where they can locally reach the gas window in the deepest depocentres. The main source rocks (Kimmeridgian and Tithonian) are generating oil during the Cenozoic and are starting to expel a few million years later. The Aptian source rock reaches only the incipient oil generation zone. The Carson, Bonnition and Salar basins are therefore a potential oil province. The main reservoirs are deposited during active tectonic phases (rifting 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.

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, and high cut-off on HC concentrations (kg/m²) in reservoir cells on the different selected scenario. Hydrocarbon resources in place (unrisked volumes) are estimated to 3.0 Bbbl of oil and 5.8 Tcf of gas unrisked (P50) trapped in the 9 licensed blocks (Figure 5).

The estimated Probability Of Geological Success to find the P50 estimate (4.0 Bboe) is 11% characterizing a medium to high risk exploration area.

<table>
<thead>
<tr>
<th>Total</th>
<th>Total Oil (Bbbl)</th>
<th>Total Gas (Tcf)</th>
<th>Total Oil &amp; Gas (Bboe)</th>
</tr>
</thead>
<tbody>
<tr>
<td>P90 Low case</td>
<td>1.5</td>
<td>3.0</td>
<td>2.0</td>
</tr>
<tr>
<td>P50 Most likely</td>
<td>3.0</td>
<td>5.8</td>
<td>4.0</td>
</tr>
<tr>
<td>P10 High case</td>
<td>7.0</td>
<td>15.0</td>
<td>9.6</td>
</tr>
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</table>

*Figure 5 Amount of oil, gas and oil+gas that can be present in all the plays within the 9 licenced parcels (Left). Distribution of unrisked volume in place and POS (Right) considering all models.*

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