Offshore Newfoundland & Labrador Resource Assessment
Flemish Pass Area NL15_01EN

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

Nalcor Energy – Oil and Gas Inc., the Provincial Energy Corporation for Newfoundland and Labrador in collaboration with the Newfoundland and Labrador Department of Natural Resources (DNR) engaged Beicip-Franlab to conduct an independent resource assessment of the Flemish Pass area.

The objective of this project was to conduct a basin analysis, play risk analysis and resource assessment for the area subject to the upcoming license round (November 2015) based on available geological and geophysical data.

The final deliverables of this project include a detailed Beicip-Franlab internal report for Nalcor and DNR and this Public Atlas which summarizes the main methodologies and key results of the Resource Assessment project.

WORKFLOW

1. Database generation and QC;
2. Tectonic setting;
3. Sedimentology, sequence stratigraphy and geochemistry;
4. Petrophysics evaluation ($V_{\text{shale}}$, porosity, saturation);
5. Gross Depositional Environment (GDE) maps;
6. Stratigraphic modelling;
7. 1D, 2D & 3D Petroleum System Modelling;
8. Play Risk Analysis, Common Risk Segment (CRS) mapping and volumes assessment.

MAIN RESULTS

Beicip-Franlab petroleum system resource assessment of the Flemish Pass area demonstrates a prolific petroleum system with three main reservoirs sourced by two constrained source rocks. Timing of burial regarding traps formation enables hydrocarbons (HC) to be trapped and sealed regionally through rotated Jurassic and Cretaceous blocks and large Cretaceous turbidite complexes.
The Eastern Newfoundland Region represents part of the North Atlantic Mesozoic rift system which includes the Jeanne d'Arc, Orphan and Flemish Pass basins.

In January 2015 Nalcor Energy and Beicip-Franlab began the resource assessment of the Flemish Pass area and the study scope was set to include the NL01-EN sector (2015 license round area) and surrounding acreage for completeness.

On March 31\textsuperscript{st}, 2015 the Canada-Newfoundland and Labrador Offshore Petroleum Board (CNLOPB) announced the Call for Bids NL15-01EN and block definition of the 11 parcels of land in the previously announced NL01-EN sector with bids closing in November of 2015. The land available in this call is the first to be announced under the new Scheduled Land Tenure System. [http://www.cnlopb.ca/pdfs/cfntechdoc.pdf](http://www.cnlopb.ca/pdfs/cfntechdoc.pdf). Interested parties will have until 12:00 p.m. NST on November 12, 2015 to submit bids for the parcels offered in Call for Bids NL15-01EN. Further detailed information pertaining to this Call for Bids can be found at: [www.cnlopb.ca/exploration/issuance.php#bids-active](http://www.cnlopb.ca/exploration/issuance.php#bids-active).
DATA SET

10 wells were used for the study, each one of them contains a set of petrophysical logs, stratigraphic markers and geochemical reports:

- Baccalieu 1-78
- Gabriel C-60
- Great Barasway F-66 (outside the study area)
- Kyle L-11
- Lancaster G-70
- Lona O-55
- Mizzen F-09
- Mizzen L-11
- Mizzen O-16
- Tuckamore B-27

5 recent wells inside the study area are not yet released and therefore not included in the study.

3 wells contained core data:

- Baccalieu 1-78
- Gabriel C-60
- Lancaster G-70

2D seismic surveys (regional and 5x5 km grid) interpreted by Nalcor covering an area of 84000km² within the Orphan/Flemish Pass basins (2012-2014 Nalcor invested TGS/PGS broadband long offset multiclient NE Newfoundland Slope Seismic Project).

A set of 10 horizons were interpreted in both surveys:

- Seabed, 0 My
- C10, Mid Neogene, 10 Ma
- C24, Top Paleocene, 24 Ma
- C45, Top Mid Eocene, 45 Ma
- C65, Top Cretaceous, 65 Ma
- K114, Top Mid Aptian, 114 Ma
- K137, Top Valanginian, 137 Ma
- J145, Top Tithonian, 145 Ma
- J151, Top Kimmeridgian, 151 Ma
- Base Mesozoic, 251 Ma

5 associated isopach maps.

Fault sets picked for structural evolution, reconstruction, and 3D Modelling.

In May 2014 the NL01-EN Sector was released by the CNLOPB, followed by the release of Call for Bids NL15-01EN in March 2015. By the end of March, when the Call for Bids was released, the land boundaries changed from the NL01-EN sector. At this point, the resource assessment project had all mapping of the area complete and the modelling phase had begun. With the land boundary changes the study area originally outlined by Nalcor and Beicip-Franlab did not completely encompass the new land block design, and the north west corner of block NL15-01-04 now extends outside of the study area for this Resource Assessment. This outlier region represents a very small portion of the project area and has no impact on the study outcome.
Regional seismic interpretation

The seismic interpretation of the sector covers the entire Upper Jurassic to present day. It was calibrated on the various wells available for the study area.

The regional seismic interpretation on a 5x5 km grid was adapted to the play study scale. It identified the main traps (with a minimum of 10 km²), the main structural features (depocenters, 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 - channels, deep sea fans, etc.

This interpretation highlighted traps with in-place volumes of the order of 100 MMbbl equivalent (10-15 Mm³) or higher. The detailed analysis of trap contour and actual size as well as detection of smaller traps requires a finer spacing or 3D seismic data.

Well geological data

Comprehensive well information on the 10 wells available within the study area or in its vicinity (logs, paleo-environment data, core, temperature, pressure, HC recordings) as well as regional geological studies on Eastern NL and existing well correlations were used. This data provides a reliable framework for the play definition, internal subdivisions and key characteristics of the wells such as net-to-gross, reservoirs, average porosities, carriers and seal occurrence.

Geochemical and petroleum data

The maturity data for the wells was abundant although not very precise (Ro, Tmax). Maturity data can be correlated to well logs and used for comprehensive building of TOC logs. TOC measurements were made on cuttings and cores. The existence of a proven and efficient petroleum system in the neighboring basin (Jeanne d’Arc), with similar geologic characteristics, provides a useful analogue for the Kimmeridgian source-rock characterization. Although no precise volumetric information on discoveries (Mizzen, Bay du Nord, Harpoon) was available, general data on the HC occurrence (saturated HC intervals at the play resolution scale) and type allow for a realistic quantitative calibration of HC volumes.

Reliability and accuracy of the resources assessment.

The data quality ensured that a reliable and reasonably well constrained 3D geological model of the area could be built. The corresponding oil & gas resource assessment can be undertaken within an acceptable accuracy covered through the low and high cases, constrained by observations.
PLAY AND YET TO FIND HC RESOURCE ASSESSMENT METHODOLOGY

DEFINITIONS

• The Play and Yet-to-Find HC resource assessment methodology follows the Petroleum Resources Management System (PRMS) Guidelines (2011) for Prospective and Contingent Resource assessment.

• The assessment was based on the deterministic computation in the area of interest of oil and gas volumes in place. The simulation includes 3D numerical geological models of lithofacies distribution (sedimentary system modelling) and of 3D structural oil and gas generation/expulsion/migration and entrapment (petroleum system modeling). The software packages used are DionisosFlow™ (for sedimentation) and TemisFlow™ 3D (for petroleum system).

• 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 3rd 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% for instance).

• The calibrated geological model was considered as a Reliable Reference Geological Model (RRGM) or REFERENCE SCENARIO of the various plays.

UNRISKED VOLUMES

• Some numerical parameters of the Reliable Reference Geological Model (RRGM) may remain unconstrained while still allowing for a consistent calibration against observed data.

• The computed oil and gas volumes resulting from the RRGM numerical simulation (Total and Yet to Find) are referred to as UNRISKED Volumes.

The sensitivity analysis performed on the RRGM provides a distribution of computed UNRISKED volumes which can be characterized by the P90, P50 and P10 thresholds on the volume distribution curve obtained from the sensitivity runs outcomes.

EXPLORATION HISTORY

The drilling of Tors Cove D-52 in the early 1960’s marked the beginning of hydrocarbon exploration in Newfoundland and Labrador’s offshore. To date, nearly 160 exploration wells have been drilled in Newfoundland and Labrador’s offshore jurisdiction. Many of these wells have been drilled in the Jeanne d’Arc basin where currently four fields are in production and one slated to start production in 2017. Production to date has been in excess of 1.5 billion barrels of oil.

Exploration in the deeper waters of the Eastern Newfoundland Region (Orphan/Flemish Pass basins) followed the initial exploration on the Grand Banks. The first well in the assessment area, Gabriel C-60, was drilled in 1979 and encountered Hibernia equivalent reservoir; however, no mature source rock. The Baccalieu L-78 well (1986) encountered good early Cretaceous reservoirs and confirmed the presence of good Kimmeridgian source rock. Subsequently, Lancaster G-70 encountered late Jurassic sandstones and also Kimmeridgian source rock. Also drilled in 1986, the Kyle L-11 well encountered early Cretaceous reservoir sandstones.

After a decade of no activity, new multi-client, exclusive seismic grids and the first 3D survey were collected. In 2003, Petro Canada et al. drilled Mizzen L-11 and intersected excellent reservoirs in the early Cretaceous and late Jurassic. This well 5m of light oil pay in early Cretaceous sandstones; however, non-economic. In the same year Tuckamore B-27 was drilled by the same companies. Tuckamore drilled through thick Cretaceous sandstone; nevertheless, it was wet and the well was TD’d before reaching the Jurassic interval. However, new 2D seismic over this well location indicates a thick Jurassic aged section.

In December 2008, Statoil et al. spudded Mizzen O-16 and on April 8, 2009 announced an oil discovery. The well tested oil from late Jurassic sandstones and spurred a renewed interest in the Flemish Pass Basin.

With the emergence of Newfoundland and Labrador’s Crown Energy Company (Nalcor Energy) 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). A subset of the satellite data acquired during this survey imaged areas of potential natural seepage in the Eastern Newfoundland Region (Orphan/Flemish Pass basins), suggesting a regional working petroleum system and coupled with the recent 2009 Mizzen O-16 discovery highlighted potential new areas for oil exploration. To better understand the potential nature of prospectivity in this region, in 2012 Nalcor invested with global seismic companies TGS and PGS in a long offset broadband 2D multi-client seismic grid of 10x10 km data over the Flemish Pass area. This survey was an extension of the 2011-2012 Nalcor invested TGS and PGS regional 2D seismic program targeting the slope and deepwater areas offshore Labrador. In 2014, the initial 10x10 km grid was infilled resulting in a 5x5 km grid over the area. Also in 2014, a new multi-client 3D wide-azimuth Nalcor invested CSEM survey was acquired by EMGS to help characterize and de-risk leads in this area.

The most recent oil discoveries by Statoil et al. – Harpoon and Bay du Nord (2013) – are surrounded by the parcels outlining the current Call for Bids (NL 15-01EN). The Bay du Nord discovery was described as the largest oil find in the world for 2013 with estimates from Statoil of 300 to 600 million barrels of oil recoverable.

In the eastern side of the Orphan Basin, the Great Barasway F-66 well (2006) drilled a thick Jurassic aged section containing Tithonian and Kimmeridgian source rock. Even though this well was unsuccessful in a discovery, it yet again demonstrated the presence of regional source rock. The Lona O-55 well drilled in 2010, although unsuccessful in a petroleum discovery, it also encountered a thick Jurassic section.
TECTONIC SETTINGS

Regional and detailed fault mapping were assessed in order to provide constraints on the timing of fault activities in regards to the oil expulsion, migration pathways and trapping (in the 2D section and 3D model).

The Flemish Pass and the East Orphan basins are affected by 3 consecutive extensional episodes. The timing of the deformations and the main direction of the faults are compatible with the complex Mesozoic rifting history of the North Atlantic margins. The Late Jurassic to Early Cretaceous rifting which led to the spreading between Newfoundland and Iberia in the late Early Cretaceous is well expressed in the study area. This timing is responsible for main fault related trap opportunities, especially at Tithonian reservoir levels.

Two regional transects are interpreted in terms of tectonic activity in order to enable sound petroleum system modelling. Four main phases of fault activity are recognized.

10 depth maps were picked from the seismic grid and used to define the skeleton of present-day model geometry.
While individual faults have been interpreted on seismic, only the main regional fault trends have been inserted in the model. These structures were deemed likely to impact the regional migration character for the area and thus used in the modelling.

In the 3D petroleum system model, they behave as either pressure barriers and/or have limited impact on fluid flow. This is especially true from late Cretaceous on as they are sealed by overlying stratigraphy.

This initial 3D petroleum system model (10 stratigraphic layers) has been subdivided in 35 layers, enabling the identification of main components of the petroleum system, while preserving the main regional lithological and sequence stratigraphic events.

To create this petroleum system model (shown above), the 3D stratigraphic model was then upscaled to 24 layers for the interval between Tithonian and Top Cretaceous maintaining regional geological context and keeping the highest degree of information.
Late Jurassic (Pre-Tithonian) Faults (in red): This fault set corresponds to normal faults that are sealed by the J145 horizon (top Tithonian) and root down into the continental crust. Their geometries suggest that these faults root in a ductile shear level, presumably in the middle or lower continental crust. The hanging wall blocks rotate along the fault surface defining crustal fault blocks. This extensional phase is interpreted as the major rifting phase related to crustal thinning.

Early Cretaceous (Pre-Valanginian) Faults (in blue): This fault set is sealed by the K137 horizon (top Valanginian). Most of these faults are connected with the pre-Tithonian faults (in blue) suggesting fault reactivation. Consequently, some Early Cretaceous basins formed locally. Some others faults do not show clear down-dip continuity at depth and may root in early Cretaceous sediments or in older levels. This stage marks the second major extensional phase which shaped the Flemish Pass Basin and the East Orphan Basin.

Late Early Cretaceous (Pre-Middle Aptian) Faults (green): The third fault set is sealed by the K114 horizon (Middle Aptian). Most of these faults are connected with the older faults suggesting fault reactivation. Some faults seem to root in early Cretaceous sediments or even in older levels. The magnitude of this extensional phase is less important and is interpreted as a second stage of the Early Cretaceous rifting phase.

Late Cretaceous (Pre-Tertiary) Faults (in orange): The last fault set is sealed by the C65 horizon (Base Tertiary). Most of these faults are rooted in older sediment intervals. The fault throws are smaller compared to the previous fault set. This extensional phase has a minor impact of the structuration of the Flemish Pass and the East Orphan Basin.
GEOLOGY SETTINGS

All geological information (markers, core interpretation and well logs) were integrated and interpreted in terms of sedimentology and petrophysics in order to provide a consistent stratigraphic framework constraining Gross Depositional Environment maps (GDE) for each sequence.

The log petrophysical interpretation provides updated lithological profiles, porosity and saturation curves over the main targeted intervals. This interpretation was used to better calibrate the model responses (using stratigraphic and petroleum system modelling software). The methodology used is a classical petrophysical deterministic workflow starting with the Volume of Shale ($V_{shale}$) calculation. Next, lithology logs were generated using all available information such as mudlogs, cores, sidewall cores, etc. Finally, porosity and saturation were evaluated after calibration. Nine (9) wells were included in the petrophysical study: Tuckamore B-27, Gabriel C-60, Lancaster G-70, Kyle L-11, Mizzen L-11, Mizzen O-16, Mizzen F-09, Baccalieu I-78 and Lona O-55.

Depositional and sedimentological observations were obtained from a few cored intervals acquired on Mizzen F-09, Lancaster G-70, Gabriel C-60 and Baccalieu I-78. They demonstrate a Jurassic/Cretaceous system consistent with clastic shelf deposition representative of delta front to pro-delta facies type with lateral variation to wave dominated shoreface. The Mizzen paleo-high consists of more proximal conditions with the presence of fluvial sandstones in the Tithonian. Based on these facies, structural setting may play a key role on the presence of reservoir, as paleo-highs and local uplift will provide sources for sediments to be distributed in the basin.

The Cretaceous stratigraphy is interpreted to be more of a distal system dominated by large turbidite depositional packages shed from the paleo-highs.
The stratigraphic framework has been updated to tie to well stratigraphic correlations and seismic interpretation. Main time markers (P_251, J_151, J_145, K_140, K_114, K_100, C_65, C_54, C_45, C_34 and C_24) were picked. This breakdown, once integrated with the core facies interpretation, highlights the presence of Tithonian fluvial reservoirs on the highs of Mizzen that laterally transition to distal deltaic and/or shorface settings in the Lona area. Also, lower Cretaceous (Valanginian) shoreface sandstones were encountered in the Gabriel / Tuckamore area, and southeast at Kyle L-11. The upper Cretaceous, specifically around the Baccalieu well, display delta front sand bars potentially feeding turbidite complexes down-dip.

This comprehensive stratigraphic / paleoenvironment interpretation served as the basis of the sedimentological input to the Gross Depositional Environment (GDE) mapping. When coupled with thickness maps, these inputs served as the fundamental information for the DionisosFlow™ stratigraphic model.
MATURITY - SOURCE ROCK DEFINITION - METHODOLOGY

In the studied area, Total Organic Content (TOC) and Rock Eval data allowed for characterization of key parameters of source rock intervals at well location. In addition, regional extent of source rock was assessed through a Carbolog® approach to constrain the petroleum modelling.

In this approach, the TOC was computed from the combined log response between the sonic, density, neutron and resistivity.

A calibration was made using existing TOC analytic data from the study wells. The method can be represented graphically with ΔT plotted on the horizontal axis and 1/√Rt on the vertical axis. On such a cross plot, the position of the pure components (water, clay, pure TOC or matrix) allows the derivation of the TOC at a given depth. For example, a sample located along the 4% iso TOC curve, with high V_clay, will fit the average of Rock Eval measurements on a core at that depth.

VITRINITE REFLECTANCE DATA

The %Ro measurements are displayed on the graph at right for six 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 petroleum system thermal model is adjusted against the present day observed geothermal gradients at wells and against average Ro values at a given depth for a given well (+- 0.15%).

Using mean Ro values at a given depth, the top oil window depth would be around 3000m, and the late oil generation window would start at 4500m.
SOURCE ROCK DEFINITION

Results demonstrates:

• There is an existence of a richer TOC interval at the top of the Tithonian in Great Barasway, Baccalieu and Lancaster wells and potentially extending up to the Mizzen area. It's vertical pattern (TOC richer at the top) could attest of its deposition in a transgressive context with better TOC preservation (reaching more than 3%) at the top of the flooding event that eventually reaches the highs.

• The Kimmeridgian source rock potential is distributed over a large thickness (>200m) with TOC ≥1%. It is difficult to correlate a unique Kimmeridgian source level based on existing well penetrations. This is mostly due to the prodeltaic nature of the sedimentation that locally creates zone of energy dispersing the organic matter randomly.
**PLAY DEFINITION**

**Exploration Play concept**

According to Society of Petroleum Engineers (SPE) - PRMS definition, a "play - or petroleum play" is a model of how a petroleum system (HC charge, reservoir, seal, 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).

### Plays / Elements

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<th>Source Rock</th>
<th>Equivalent Reservoir Analogue</th>
<th>Seal</th>
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<tr>
<td>Aptian/Albian</td>
<td>Kimmeridgian (Egret Mbr) &amp; Tithonian</td>
<td>Ben Nevis</td>
<td>Upper K to Tertiary</td>
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<tr>
<td>Valanginian</td>
<td>Catalina</td>
<td>Top Valanginian to Upper K</td>
<td></td>
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<tr>
<td>Berriasian</td>
<td>Hibernia</td>
<td>Top Berriasian to Upper K</td>
<td></td>
</tr>
<tr>
<td>Tithonian</td>
<td>Jeanne d'Arc</td>
<td>Top Tithonian / Berriasian to Upper K</td>
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**Wheeler diagram**

[Diagram showing geological layers and play elements]
Within the NL_15_01 license area there are multiple Cretaceous Fan plays. These fans are large in scale and have been imaged over multiple 2D seismic lines within the license area. Many display an AVO response when viewed in the gathers and on the near and far angle stacks.

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

This particular example of a Cretaceous Fan play within the license round area may contain a possible flat spot that coincides with where the AVO anomaly dims significantly.

Seismic data from Nalcor invested TGS/PGS multiclient 2D broadband long offset seismic program offshore Newfoundland (2012-2014)
Within the NL_15_01 license area there are multiple Jurassic tilted fault block plays. These structural plays exhibit a classic architecture and some have been imaged over two or more 2D seismic lines within the license area. Many display an AVO response when viewed in the gathers and on the near and far angle stacks.

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

This particular example of a Jurassic structural play within the license round area shows updip amplitude strength in the far angle stack.
Within the NL_15_01 license area there are multiple Upper and Lower Cretaceous fault block plays. These structural plays exhibit a classic architecture and some have been imaged over two or more 2D seismic lines within the license area. Many display an AVO response when viewed in the gathers and on the near and far angle stacks.

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

Seismic data from Nalcor invested TGS/PGS multiclient 2D broadband long offset seismic program offshore Newfoundland (2012-2014)
A set of 6 GDE maps spanning the main sequences were built from the stratigraphic / sedimentological information coupled to the seismic data (thickness and structural maps). They represent the paleoenvironments at given ages that served as input to the stratigraphic basin Modelling (DionisosFlow™), specifically through constraining the paleobathymetric / paleoenvironmental changes through time and space. From the Kimmeridgian onwards, facies are mainly driven by rift related fluvio/deltaic environments that transition basinwards into distal turbidite complexes. A variety of reservoir types can be expected from the Tithonian fluvial packages preserved within early-phase rift related graben terranes, to the turbidite channels and lobes preserved within the Cretaceous basins.
FORWARD STRATIGRAPHIC MODELLING: Objectives & workflow

A forward stratigraphic simulation was performed using DionisosFlow™ (an IFPEN software) in order to (1) better understand 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 the base of the Tithonian, up to the base of the Cenozoic, in sequential time steps. For each time step, three main environmental parameters were taken into account:

- The Accommodation (corresponding to subsidence and eustasy) reflects the space available for sedimentation. This information is provided by the combination of structural / depth map and paleobathymetry maps, which leads to the computation of Subsidence/Accommodation maps.
- The Sediment Supply, which may correspond to an external input (with added in situ erosion of local highs with associated drainage basins), or to in situ marine carbonate production. The sediment supply can be tuned by defining clastic sources at the edge of the model, which reproduce the sediment and water fluxes evolution through time and space.
- The quantification of Sediment Transport, using 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 10’s of kilometers.

Sedimentation and erosion were simulated at each point of the basin using mass balance principles, and then calibrated by tuning all of the environmental parameters (sources, subsidence map, transport/diffusion). Carefully considering the interplay between these 3 parameters, the main steps of the stratigraphic modelling analysis consisted of:

- Reproducing regionally the overall basin geometry evolution from late Jurassic to top Cretaceous. This implies (a) a calibration of regional sequence thickness with existing structural interpretation and sequence stratigraphic definition and (b) a reproduction of internal geometries observed on seismic profiles.
- Reproducing lithological vertical succession observed at the 9 available well locations.
- Predicting and quantifying the sedimentological distribution inside described seismic geobodies away from well calibration, and in fully unexplored areas.
- Extracting refined GDE and lithological 3D volume to the petroleum basin modelling Software (TemisFlow 3D™) and play assessment.

The simulation time ranges from the base of Tithonian (151 Ma) to the base of Tertiary erosion (65 Ma). The time step used in the simulation is 0.1 Ma (to be representative of main eustatic variations). The final 3D cube model is comprised of 890 layers. The 5 main stratigraphic sequences served as the key input for building the stratigraphic model. Reference simulations were performed successively for each of the six intervals:

- Tithonian (J151-J145),
- Lower Berriasian (J145-K143),
- Upper Berriasian-Valanginian (K143-K137),
- Hauterivian-Mid-Aptian (K137-K114)
- Mid-Albian to top Cretaceous (K114-K65) including base Tertiary erosion (K65-C62).
FORWARD STRATIGRAPHIC SIMULATION: Calibration results

The calibration phase consisted of a step-by-step setting of each time interval in-between the 7 selected time horizons. It calibrates both geometry / thicknesses for each one of the 6 intervals (seismic thicknesses), respecting shale / sand ratios recorded at the study wells.

- The thickness calibration was controlled by the difference between the input thickness and the simulated thickness after simulation. Errors were then calibrated by modifying the sediment supply and the sources locations.

- Both markers and Vshale logs were used for calibration of the stratigraphy and the shale lithology at 9 well locations. The model produced good thickness calibration of simulated markers between the wells and input markers. The main lithologies observed at wells were also respected in the simulated results.

- Seismic control of the general (thickness) and specific geobodies and stratal terminations (such as onlap, toplap and truncation geometries) were reproduced.
3D FORWARD STRATIGRAPHIC MODELLING: Facies definition – Tithonian

Facies model inputs were set as a function of percentage of clastic lithologies (% of sand, shales and carbonate) and paleo-environmental data (paleobathymetry and water flow energy on the slope). Eighteen individual facies were discriminated at relevant stratigraphic intervals (based on main tectono-stratigraphic system tracks such as highstand and lowstand in order to capture large scale lithological variation spatially and vertically). From 151 Ma to 62 Ma, 23 gross depositional maps were created and integrated in the TemisFlow™ modelling as lithology properties.

For the Tithonian interval, 60 layers were simulated in the stratigraphic forward model and then upscaled in 6 representative layers with associated lithofacies properties for the use in petroleum system modelling for the basin.

Lithofacies discrimination

Lithofacies map

3 Samples out of 60 Tithonian Layers
3D FORWARD STRATIGRAPHIC MODELLING: Facies definition – Berriasian

Facies model inputs were set as a function of percentage of clastic lithologies (% of sand, shales and carbonate) and paleo-environmental data (paleobathymetry and water flow energy on the slope). Eighteen individual facies were discriminated at relevant stratigraphic intervals (based on main tectono-stratigraphic system tracks such as highstand and lowstand in order to capture large scale lithological variation spatially and vertically). From 151 Ma to 62 Ma, 23 gross depositional maps were created and integrated in the TemisFlow™ modelling as lithology properties.

For the Berriasian interval, 44 layers were simulated in the stratigraphic forward model, and then upscaled in 5 representative layers with associated lithofacies property for the use in petroleum system modelling for the basin.
3D FORWARD STRATIGRAPHIC MODELLING: Facies definition – Valanginian

Facies model inputs were set as a function of percentage of clastic lithologies (% of sand, shales and carbonate) and paleo-environmental data (paleobathymetry and water flow energy on the slope). Eighteen individual facies were discriminated at relevant stratigraphic intervals (based on main tectono-stratigraphic system tracks such as highstand and lowstand in order to capture large scale lithological variation spatially and vertically). From 151 Ma to 62 Ma, 23 gross depositional maps were created and integrated in the TemisFlow™ modelling as lithology properties.

For the Valanginian interval, 46 layers were simulated in the stratigraphic forward model, and then upscaled in 5 representative layers with associated lithofacies property for the use in petroleum system modelling for the basin.
FROM SEDIMENTOLOGY / STRATIGRAPHY TO MODELLING

Initial stratigraphic interpretation (geology at wells & GDE mapping)

3D Forward Stratigraphic Model (sand proportion over 890 layers; 4x4 km grid)

3D Forward Stratigraphic Model Facies distribution

3D Petroleum System model (23 upscaled facies 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 hydrocarbon generation, expulsion, migration and entrapment, from the source rock until the reservoirs were simulated, taking into account both the paleo-geometry, the thermal state, fluid flow and the rock 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 Jurassic source-rocks 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** were populated using gross lithofacies maps extracted from the DionisosFlow™ results.

2D Basin Modelling Calibration: Two 2D sections were extracted from the 3D framework in order 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 in order to include key wells with relevant data for calibration. The model boundary conditions through time were defined; enabling the thermal calibration of the model, both its history 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 & migration simulation was performed using Full Darcy Compositional Migration in TemisFlow™ and taking into account the results of 2D modelling. Source rock intervals were selected in agreement with Carbolog® results and regional understanding. Their type and richness were also defined in the model. The known oil and gas accumulations and its properties were used in order to calibrate the model and understand its limitations.

The Hydrocarbon Generation through kerogen cracking was simulated by using the **Arrhenius law** defined for each hydrocarbon component in a kinetic scheme, and which is dependent to the basin temperature history:

- The Transformation Ratio property is the ratio of generated HC to initial potential. The transformation ratio is calculated only in the kerogen bearing cells, according to the kinetic reaction of petroleum formation. It is not dependent on the source-rock potential, and can be used to evaluate the level of maturity of the source-rock.
- The hydrocarbon saturation of the source rock during its generation engenders an intense increase of the source rock capillary pressure, and consequently the expulsion of hydrocarbons.

The evaluation of charge within main plays was calculated by taking into account the physical processes that govern the migration of hydrocarbon fluids. That is why full 3D Darcy migration simulation was performed. The **Darcy law** correctly models macroscopically the velocity of migration of hydrocarbon fluids with respect to buoyancy, hydrodynamism and capillarity. It also takes into account the effect of pressure, temperature as well as composition, viscosity, and density of each hydrocarbon phase. For instance, expulsion is facilitated when hydrocarbons are lighter and if the hydrocarbon pressure is higher.
2D THERMAL MODELLING

In the deepest part of the depocenters the temperature reaches 230°C. The maximum simulated temperature is 195°C for the Kimmeridgian source rock interval and 160°C for the Tithonian source rock, enough to enable a secondary cracking of oil into gas. The overall reservoir temperatures are above the 80°C at present day. It is possible that early migrated oil was biodegraded as it reached some reservoirs below 80°C which correspond to the biodegradation threshold.

The present-day source rock maturity field shows that:
The Kimmeridgian Source Rock is mature in the troughs (in deep water facies), ranging from early mature (oil window) in the shallowest parts (with shallow water facies) to overmature in the deepest depocenters.
The Tithonian Source Rock is mainly within the oil generation window. The gas generation window is only reached in the deepest depocenters.
There are 2 main regional pressure boundaries within the Jurassic, linked to the presence of regional shale units, which appear to correspond to the main source-rocks.

The most important pressure jump occurs below the Kimmeridgian source rock.

The presence of overpressure below the Kimmeridgian source rock level is a regional feature. This level acts as a regional seal. Each graben (or half graben) has a specific overpressure regime. The overpressure levels remain moderate, and are highest in the depocenter between Baccalieu and Gabriel.
In the deepest parts of the basin, the transformation ratio of the organic matter reaches 80% at present day. The Kimmeridgian source rock generation potential is fully transformed in the deepest parts of these main depocenters.

Sensitivity analysis has been performed for the expulsion timing by varying the HC saturation threshold in the source rocks before expulsion can occur. The hydrocarbon expulsion starts around 140 Ma in the deepest parts of the main depocenters; expulsion occurs until 120 to 80 Ma. In less mature areas or regions with continued sedimentation/ burial, the hydrocarbon expulsion is still ongoing (expulsion time interval between 40 and 0 Ma).

The HC quality was computed from the HC composition in oil (C6+) and Gas (C1-C5). Oil is predicted over most of the studied area. Gas and condensate are to be found in the local depocenters.
TIMING OF HC CHARGE FROM KIMMERIDGIAN SOURCE ROCK (SR)

The timing of hydrocarbon migration is variable in the basin depending on burial and source rock richness. The timing of expulsion allows different scenarios for the oil and gas migration and entrapment to be expected throughout the basin. In some depocentres the expulsion is almost completed before the end of the Cretaceous while in other areas the expulsion takes place mainly during the Tertiary up to the present day.

The Kimmeridgian source rock expulsion is documented at four different places in the basin.
The Tithonian source rock follows an expulsion pattern which is similar to the Kimmeridgian source rock, although slightly delayed. Modelled expulsion occurs during Cretaceous in the thickest depocenters, with Tertiary-aged expulsion elsewhere.
The source rock maturity was computed for each layer of the 3D reference model through geological time. The source rock maturity (in equivalent Ro) is presented for the Kimmeridgian:

The Kimmeridgian passed through the oil window over most of the depo centers during Upper Cretaceous (100 Ma). The oil expulsion starts around this time, and can effectively charge traps which are present. The maturity further evolved up to the dry gas zone in the deepest areas.
TITHONIAN SOURCE ROCK EVOLUTION THROUGH TIME

The source rock maturity was computed for each layer of the 3D reference model through geological time. The source rock maturity (in equivalent Ro) is presented for the Kimmeridgian:

The top of the oil window for the Tithonian was crossed later than in the Kimmeridgian source-rock case. The oil expulsion has started later, and can contribute to a second HC charge phase after the Kimmeridgian oils.

The maturity further evolved up to the wet gas zone in the deepest areas.
The Unrisked Volume of Hydrocarbon corresponds to the amount of oil (in Bbbl), gas (Tcf) and Oil+Gas (in BOE) that can be present in the plays (expressed in high, medium and low chances), according to one base case geological scenario. Uncertain variables such as TOC, seal retention capabilities, oil and gas saturation cutoffs, have been accounted for. The base case scenario also honors the observations on pressure, temperature and oil accumulations within the resolution of the geological model and within the uncertainties on measurements / observations. The impact of the uncertain variables is evaluated through sensitivity analysis.

The unrisked volumes are presented as high, medium and low chances over 20 TemisFlow™ scenarios (all calibrating the thermal, pressure model and discovered volumes where known) for each of the four main plays.

The volumes described here are aggregate, summed volumes for the 11 blocks and do not include additional volumes outside of the blocks but within the study area.
RISK ANALYSIS

Probability of Success \( POS = P_c \times P_s \times Pr \times Pt \)

The RRGM has a certain probability of being accurate. This global probability is usually decomposed into 4 main independent terms which are partly addressed during the sensitivity analysis.

RISK EVALUATION AND POS

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

The HC charge thresholds are defined by average amount of charge HC / km² (eg > 500 kg/m²) in the play or play sector (cumulated over the source rock vertical thickness).

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

The trap risk was defined by trap volume threshold and fill spill analysis (number of traps with porous volumes > 10, 50, or 100 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 Composite Common Risk Segment map (CCRS) and is obtain by superimposing the individual CRS maps.

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

- \( P_c \) = HC charge probability
- \( P_s \) = Seal Presence and efficiency
- \( Pr \) = Reservoir presence and quality
- \( Pt \) = Trap existence (in the case of regional 2D seismic grid and interpretation)

Presence & Effectiveness maps

CRS maps

CCRS maps

RISK SCALE

- High risk that the petroleum system component is not efficient (or low probability that it is efficient)
- Medium risk
- Low risk

Risked volumes are the product of:

\( P_s \times P_c \times Pr \times Pt \times \text{UNRISKED volumes at a given probability (eg. P50)} \)

In this approach, the risked volumes are usually lower than the Prospective Oil Initially In Place (OIIP) and Gas Initially In Place (GIIP) resources, and will not correspond to actual volumes to be expected during the exploration of the traps and leads. The risked volumes are used to rank the blocks or sectors between themselves. The plays can also be ranked by adding all risked volumes.
PETROLEUM SYSTEM ELEMENTS RISKING

Common Risk Segment (CRS) mapping was performed based on the reservoir and seal elements considering their presence and efficiencies. Using the full resolution forward modelling stratigraphic 3D grid (one play example presented here) CRS maps took into account elements such as net sands and net shale but also the thickness of vertically continuous beds. For example 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 20 m 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 modeling. (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.

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).
BLOCK RANKING

UNRISKED VOLUMES WEIGHTED BY PROBABILITY OF GEOLOGICAL SUCCESS

The P50 UNRISKED Volume can be weighted by the Relative chance between blocks to find such volumes, in order to rank the blocks between themselves.

The relative chance is a Probability scale (from 0 to 1) resulting from the product of a relative POS for reservoir and relative POS for seal.

The Unrisked HC volumes are computed by block.

The POS x Unrisked Volume P50 case are summed for all four plays. They are known as total risked volumes.

The block ranking is obtained from the highest total risked volume to the lowest.

The block by block ranking and risked resource numbers by block are detailed in the Beicip-Franlab internal Nalcor/DNR report.
CONCLUSION

PETROLEUM SYSTEM CHART

A synthetic petroleum chart illustrating the petroleum components and timing of generation, expulsion, migration and entrapment of hydrocarbon is proposed:

- The main and proven source rocks (Kimmeridgian and Tithonian) are generating oil during the lowermost Cretaceous and are starting to expel oil a few million years later to the north of the study area.
- Maturation and expulsion occur much later to the south (Tertiary), due to late burial of late Jurassic layers (Jeanne d’Arc margin sedimentation and progradation from the South).

Since the basin evolution was well advanced the Tithonian and lowermost Cretaceous sands were already deposited. The timing of maturation and expulsion is compatible with oil and gas entrapment in these main plays.

The Tithonian appears to yield the highest oil and gas volumes in place due to an efficient vertical migration from the source and significant lateral migration within the Tithonian interval.