CHAPTER 1

INTRODUCTION TO THE CENTRAL SCOTIAN SLOPE STUDY

Introduction

Since 2009, the Offshore Energy Research Association (OERA) has made a significant research investment in assessing hydrocarbon prospectivity, in order to restore the Scotian Margin attractiveness to oil and gas companies (OERA, 2011; OERA, 2014; OERA, 2015). International Oil Company interest was materialized in 2012 with almost 2B$ investment from Shell and BP (Figure 1). Later in 2015, Statoil leased two parcels for CAN$ 82M$ in Shelburne Sub-basin (Parcels one and two, Figure 1). Over the 3 year period from 2012 to 2015, approximately 2/3 of the margin was licensed by three major companies, highlighting the rapid change in opinion regarding Nova Scotia's offshore hydrocarbon potential.

As an extension of the work undertaken since 2009, a study focused on the Central Scotian Basin (the Sable Sub-basin) has been conducted in support of the 2016 call for bids (NS16-1; http://www.callforbids.ca/). The shelf portion of the study area has been an oil and gas producer since the late 1960s, with the first well drilled by Mobil in 1967 on Sable Island. The 1990s saw the development of the Sable Offshore Energy Project (SOEP) and the discovery of the Deep Panuke oil and gas field where production started in 2013. In 2002, a gas discovery in Cretaceous turbidite reservoirs was made offshore with the Annapolis G-24 well. The Annapolis discovery was not tested because of mechanical problems and the well was abandoned. Annapolis does prove, however, a working play in the Lower Cretaceous in deep water. All information regarding post-drill analyses is given in Kidson et al. (2005) and (2007), and information regarding the hydrocarbon potential at the Scotian Basin scale is available in the Play Fairway Analysis (2011).

The objective of the current study is to build a more detailed and comprehensive understanding of the petroleum system in the Central Scotian Slope region and reassess its hydrocarbon potential in light of the most recent geological advances in the area. This Atlas is organized as follows:

- A review of regional tectonics followed by a more focused overview of the Sable Sub-basin tectonic history including the influence of salt (Chapter 2);
- An overview of the geological setting followed by an update of the stratigraphic framework based on new wells and seismic interpretation of the area (Chapter 3);
- An update of seismic horizons interpreted during the PFA, 2011, with a particular focus on Late Jurassic to Early Cretaceous horizons. The J163, J150 and K137 have been reinterpreted following the work on the Banquereau Synkinematic Wedge published by Deptuck et al. (2014) (Chapter 4);
- A seismic characterization using acoustic inversion of the Marathon seismic cube in an attempt to highlight reservoir distribution (Chapter 5);
- Following the seismic interpretation and stratigraphic sequence work, seismic stratigraphy was performed on three dip transects in order to highlight depositional system architecture and reservoir distribution from shelf to slope. These studies are integrated to generate Gross Depositional Environment maps for each key interval (Chapter 6);
- An evaluation of the petroleum system is made using TemisFlow modelling (Chapter 7) and a leads and parcels ranking is produced using the TemisFlow trap charge assessment tool as well as conventional geosciences methods (Chapter 8).

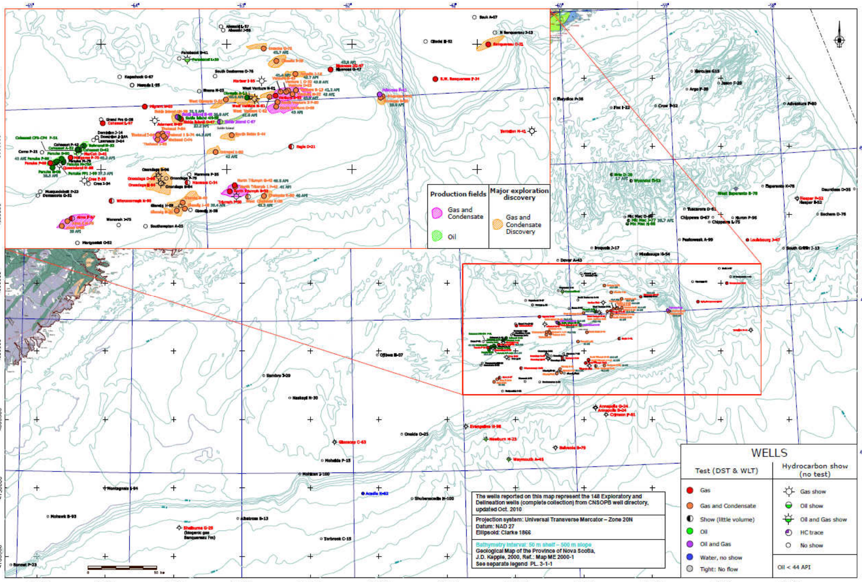


Figure 2: Regional hydrocarbon distribution from wells (from OERA, 2011).

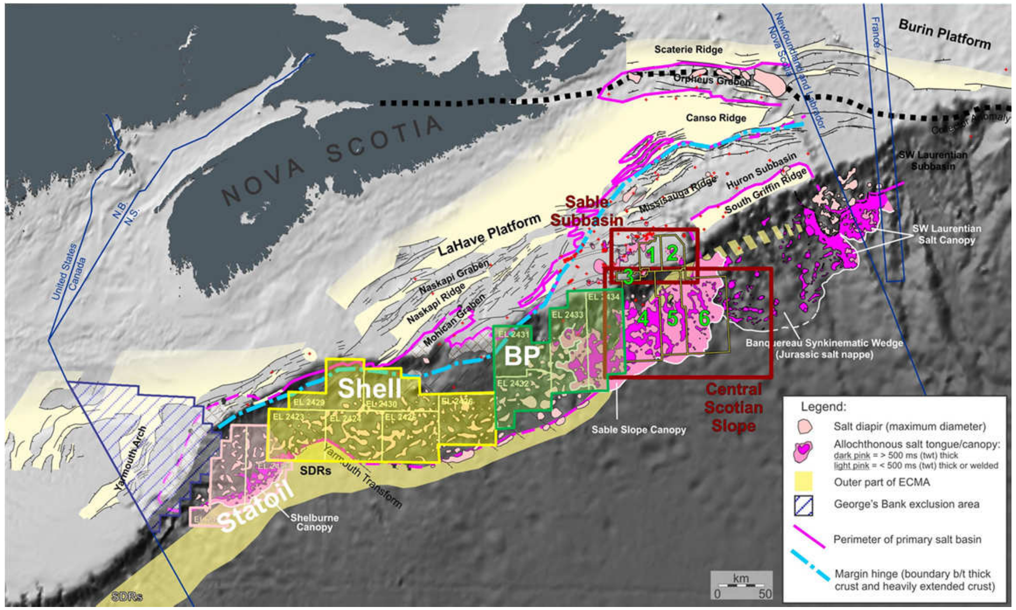


Figure 1: Basemap of the Scotian Margin showing distribution of key structural elements (From Kendell et al., 2016; some structural elements are from Deptuck and Kendell, in prep).

Geological Inheritance from 2011 PFA

The current study is the latest in a series that began in 2011 with the Play Fairway Analysis covering the entire Scotian Margin. Results are available at http://energy.novascotia.ca/oil-and-gas/offshore/play-fairway-analysis.

One of the main results of the work at that time was a better understanding of the geological complexity of the area and the significant impact of salt tectonics leading to synkinematic sedimentation. The main conclusions from the work on tectonics were that:

- Lower and Upper Cretaceous deposits are strongly controlled by salt tectonics (synkinematic wedge and salt structures);
- Two major salt layers (autochthonous and allochthonous) inducing a Roho system were active during Cretaceous reservoir deposition;
- Autochthonous salt basins are bounded by a structural high at the Continent-Ocean Boundary (COB);
- Transverse faults (diapirs) induce structural segmentation of the slope area.

Focusing on the slope in Sable Sub-basin, postmortem analysis completed on Balvenie B-79, Crimson F-81 and Annapolis G-24 wells showed that targeted traps are located in Cretaceous "synkinematics wedges" controlled by basal detachments in allochthonous salt, but the wells were not optimally located. With the exception of Annapolis, the other deep water wells did not show good reservoir intervals, although gas shows were observed. RMS amplitudes analysis of the Marathon 3D seismic data showed that both Annapolis and Crimson wells were not located at the best position to reach high amplitude reflectors either in Albian or Hauterivian intervals.

The following conclusions were drawn:

- A deep water thermogenic gas play was proven by Annapolis;
- The main exploration risk in the slope area is mainly a reservoir issue;
- Annapolis is a gas discovery but reservoirs are thin (27 m of net pay over 3 zones H, M, L);
- Reservoirs found at Crimson and Annapolis have good porosity (12 to 15 %), even below 5000m;
- Seismic attributes from 3D data indicate that Crimson and Annapolis were probably not drilled at the best location to find thick reservoirs.

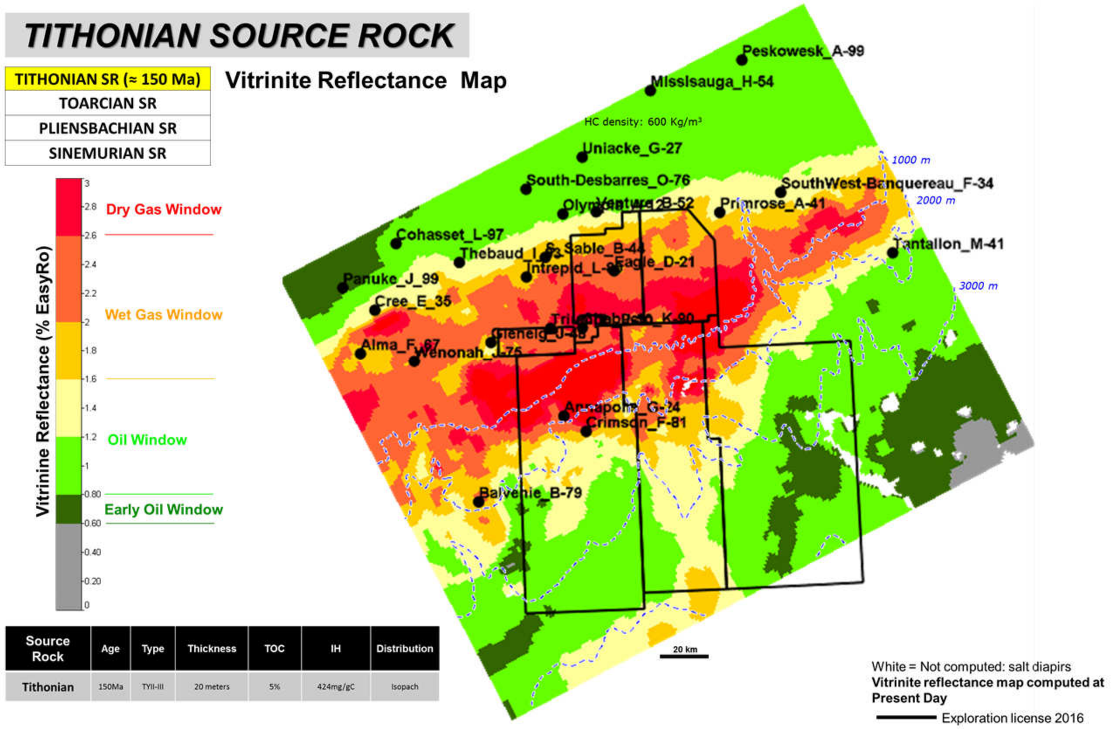
Executive summary

Key conclusions from the study are summarized here, with a focus on basin modelling results and leads and parcels ranking. Results on source rocks are presented first, followed by a short paragraph on reservoir presence and distribution. The summary ends with the leads assessment and parcels ranking.

Source Rocks

A geological model with four source rocks was used in the basin modelling: Sinemurian, Pliensbachian, Toarcian and Tithonian. The Tithonian (J150) is considered to be the main source rock in the basin and is inferred to be a type II-III source rock. Its extension is assumed to be similar to the one used for the PFA 2011, but the depth of the source rock has changed in the Banquereau Synkinematic Wedge (BSW) area (see Chapter 4). The change in depth follows Deptuck et al. (2014) which explains that the BSW occurs during the Callovian to Tithonian interval, which therefore implies that the J150 horizon attributed to the Tithonian MFS overlays the BSW. The consequence of shallower depth of the source rock is that the lower part of the basin now falls within the Oil Window (Figure 3).

Figure 3: Vitrinite reflectance (%Ro) map of Tithonian source rock at present day.



Source Rock	Age	Type	Thickness	TOC	IH	Distribution
Tithonian	150Ma	TYII-III	20 meters	5%	424mg/gC	Isopach

Evidence for Reservoirs

The presence of hydrocarbon reservoirs bearing significant resources is proven on the shelf. Finding reservoirs on the slope is riskier, given the history of failed deep water wells. The Annapolis G-24 well provides evidence for good reservoirs, even at depths of about 5000m. Detailed work on sequence stratigraphy, lithostratigraphy and seismic stratigraphy shows that reservoirs are well distributed across the slope for each key interval, but that their location is difficult to predict because of salt tectonics (Chapter 6). In fact, the most challenging aspect is not finding reservoirs, but finding thick reservoirs. Because of the salt tectonics and related margin deformation, significant sediment trapping systems may have formed at the shelf edge and upper slope for a specific time interval, particularly during the Barremian – Albian interval, which corresponds to the formation of the salt canopy. DionisosFlow™ stratigraphic modelling performed for the Upper Missisauga – Logan Canyon interval shows that an efficient trapping system does exist at the shelf edge and upper slope, but that a significant part of sands reach the lower part of the system (Figure 4; Chapter 6.2).

Results suggest overall sand proportions between 10 and 25% in deep water in salt induced mini-basins (e.g. Balvenie B-79; Annapolis G-24). In the eastern part of the area more sand is predicted, draping gentle deformations, with sand proportions varying along the studied interval from 20-25 % (Figure 4).

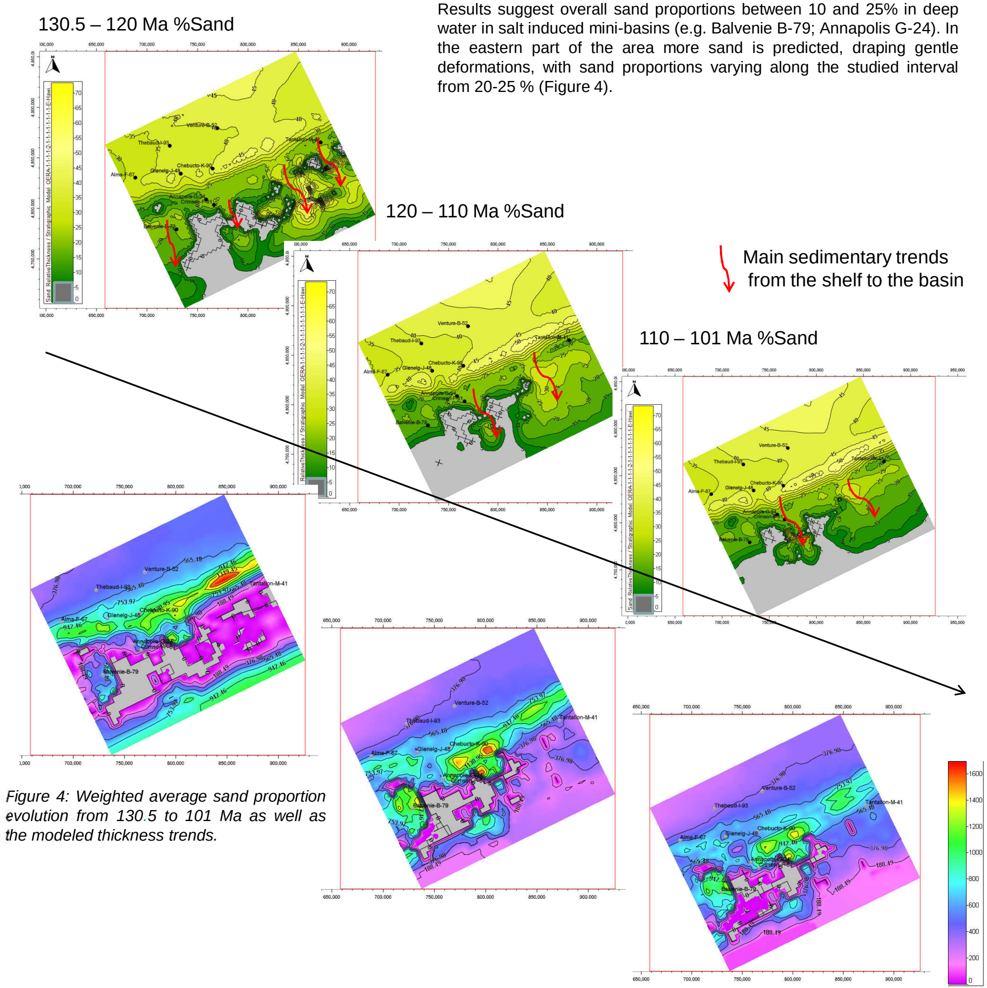


Figure 4: Weighted average sand proportion evolution from 130.5 to 101 Ma as well as the modeled thickness trends.

Leads assessment and Parcels ranking

Two approaches have been used for leads assessment and parcels ranking. The first was based on TemisFlow™ modelling and the second applied conventional geoscience methods. Detailed results of leads assessment and parcels ranking are given in Chapter 7 (PL. 7.3.19 to 7.3.25) and Chapter 8.

For basin modelling, migration simulations (calculation of HCs and water movements within the porous media) are performed using Full Darcy capabilities of TemisFlow™ in a 2 km * 2 km grid with a high vertical resolution. The volumetric calculations for the leads result from the redistribution of migrated HC in a 1 km * 1 km grid using the Trap Charge Assessment tool of TemisFlow™. The redistribution is based on topographical analysis (in terms of flow lines and drainage areas – Ray Tracing approach) of the top horizon of the analyzed layer/play (Chapter 7, PL. 7.3.1). A definition of thresholds for hydrocarbon fluids concentration (in terms of masses/m^2) is defined. Hydrocarbon quantities below these thresholds are discarded from the volumes computation as they are considered non-pay.

For the geoscience methods, two scenarios were defined:

- A scenario in which generated hydrocarbons are only Gas and Condensate (Scenario 1);
- A scenario in which generated hydrocarbons are Oil and Gas (Scenario 2).

The geophysical part focuses on what are considered to be the top 10 leads. TemisFlow™ modeling allows for a check of selected leads and gives volumes of oil and gas for each stratigraphic play within each parcel. It is important to note that the geophysical approach gives only a partial view of the resource potential, whereas TemisFlow™ results allow an estimate of the total trapped volume, as well as the type of hydrocarbon trapped and the ratio between the different phases.

Results from the geophysical approach are summarized in Figure 5. Results show a large range of values for both Oil and Gas, with similar results for Scenarios 1 and 2. Gas values range from 0.2 Tcf (K137) to 15 Tcf (K130A) with most of the values around 2 to 4 Tcf. Oil values range from 2-4 MMbbl (K137) to 1600 MMbbl (K130A) with most of the values between 140 to 470 MMbbl.

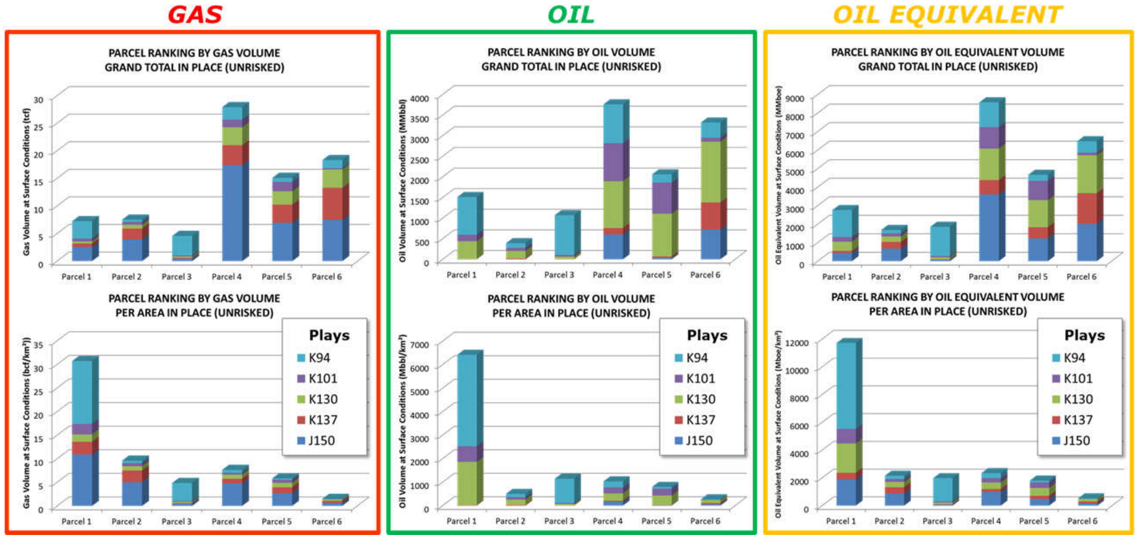


Figure 6: Distribution of hydrocarbons volume per Play and per Parcel from TemisFlow modelling results.

Results from the TemisFlow™ modeling are summarized in Figure 6 and Table 1. Total volumes for oil and for gas are presented for each parcel and for each play. Results show a large range of values for both Oil and Gas, with the largest volumes in deep water. Gas values range from less than 5 Tcf (parcel 3) to over 25 Tcf (parcel 4). Oil values range from less than 500 MMbbl (parcel 2) to over 3500 MMbbl (parcel 4) with again the largest volumes in deep water.

Overall, the modelling predicts that ~12 bnbbls oil and 80 Tcf of gas may be trapped within the 6 parcels with a distribution as shown in Figure 6. Among this, some 4.3 bnbbls and 44 Tcf is trapped in the top 10 leads.

Parcels ranking shows that deep water parcels rank better that the one on the shelf, with parcel 4 being the most attractive. Expressed into volume per surface unit, parcel 1 in the shelf appears to be the most attractive, but parcel 4 still ranks second (Figure 6).

Table 1: TemisFlow modeling grand total volume per surface unit.

Parcels	Vol Gas (tcf)	Vol Oil (MMbbl)	Total Volume (MMboe)	Vol Gas (bcf/km²)	Vol Oil (Mbbl/km²)	Total Volume (Mboe/km²)
Parcel 1	7	1512	2760	31	6418	11718
Parcel 2	8	392	1689	10	501	2158
Parcel 3	5	1072	1859	5	1144	1984
Parcel 4	28	3762	8576	8	1031	2350
Parcel 5	15	2063	4667	6	799	1807
Parcel 6	18	3319	6477	1	270	528
Total Parcels	81	12120	26028	4	592	1272

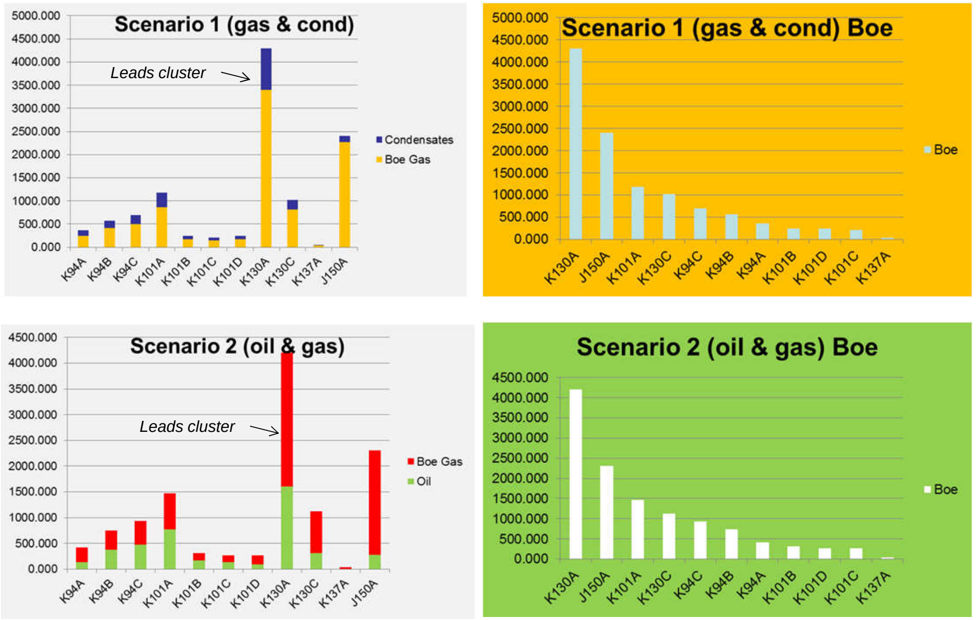


Figure 5: Distribution of hydrocarbon volume per lead based on conventional geophysical approaches.