CHAPTER 8

PETROLEUM EVALUATION

Chapter 8-1 describes the architecture of the basin during the Triassic-Early Jurassic rifting phase horst and graben structures developed in the locus of the future Atlantic Ocean. Deepest rifted basin were filled by 2 to 4 km thick salt. After drifting phase during Early Jurassic times, structuration of the continental slope of the Nova Scotia Margin is mainly controlled by subsidence and salt tectonics. Deformation and structural traps results of the combination of salt movement induced mainly by sedimentary loading. Basement faults, sedimentation rates, salt basin architecture and thickness will control the structural style and development of related traps. Along this passive margin, sedimentary supply is the main controlling factor and two main provinces can be distinguished:
1) the Southwestern province with less than 9 km of sediments, where traps are related to diapirs and associated mini-basins
2) the Northeastern province with more than 15 km of sediments, where traps are much more complex and related to allochthonous salt (detachment, rollover, salt tongue, canopy, turtle-back; …)
At a more detailed scale the slope area can be subdivided in four distinct sub-provinces:

- ✓ The Laurentian sub-province characterized by numerous diapirs and canopies developed on the autochtonous salt basin;
- ✓ The Banquerau Synkinematic Wedge sub-province;
- ✓ The Canopy sub-province characterized by autochthonous and allochthonous salt bodies and large canopy structures; and
- ✓ The Diapir sub-province mainly characterized by vertically raised diapirs on top of the autochthonous salt basin.

Each sub-province has different types of structural traps but most of them are related to salt tectonics:

- The Laurentian sub-province has been poorly imaged and was not precisely defined in this study.
- In the "Banquereau Syn-kinematic Wedge" sub-province most of the structures are extensional and consist of growth listric roller faults, rollover anticline, turtle-back, and possible "rafts" of isolated Jurassic blocks. Structures mainly developed during Upper Jurassic Early Cretaceous times and were sealed by Valanginian deposits. No one of these traps was recognized by exploratory wells.
- The Canopy sub-province is characterized by complex salt structures with locally a "roho" system with two salt bodies:
  - The basal autochtonous salt on top of which Jurassic to early Cretaceous series were faulted and tilted
  - The upper allochtonous salt body expelled from the Sable basin area and squeezed ocean ward by Cretaceous deltaic deposits. The most common and prolific structural traps is the rollover anticline with apparently poor sealing capacity of listric faults.
- The diapir sub-province is characterized by vertical circular diapirs or SW-NE elongated wall of salt directly connected to the autochthonous salt basin. In this part of the margin, type II marine source rock could have generated liquid hydrocarbon with entrapment in the classical salt diapir related traps (overhang, flank pinch-out) or in sedimentary traps related with turbiditic sand in the mini basins.

Chapter 8-2 called "Petroleum Evaluation / CRS Mapping" shows the results of the play fairway mapping for each play in terms of risk in reservoir / seal / source rock presence and effectiveness along the entire Nova-Scotia margin. The final objective is to highlight for each play the most prospective areas of the margin.
Five potential source rocks have been identified from the geochemistry study and the petroleum system modeling. They were grouped as two major source rock petroleum systems: 1) Early to Middle Jurassic (Early Jurassic SR and Callovian source rocks) and 2) Upper Jurassic to Early Cretaceous (Tithonian, Valanginian and Aptian source rocks).
Seven plays have been selected as the results of the integration of well stratigraphy, seismic interpretation, gross depositional environment and basin modeling: Jurassic carbonate bank, Jurassic deltaic sands, Berriasian sands, Valanginian to Hauterivian sands, Barremian sands, Albian sands and Late Albian "lowstand" sands.

Jurassic carbonate play
The Jurassic carbonate play is proven by the Deep Panuke oil discoveries. The most prospective area is located in the trend of these discoveries along the reef carbonate facies. West of Deep Panucke, the charge contribution to the carbonate platform edge is increasingly attributable to the Early to Middle Jurassic petroleum system as the younger source rocks come out of the Sable Sub-basin kitchen. The traps are combining stratigraphic and structural trapping elements. A more detailed Late Jurassic play fairway mapping has been undertaken in Chapter 9.
Jurassic deltaic sands play
Jurassic delta front sands are being produced in the Sable sub-basin (Zone 3). The most prospective area extends towards the Huron sub-basin (Zone 5). The dominant trap style are growth fault related traps.
Berriasian sands play
The most prospective area is located in the Sable sub-basin (production area – Zone 3) and Huron sub-basin (Zone 5). Traps are defined as growth fault related traps. The possible play fairway in Zone 6 is associated to the Banquereau detachment zone and its potential sand accumulation during Berriasian times. In this zone traps are mainly structural (roll over structures associated to growth faults, rafts, turtle back)
Valanginian to Hauterivian sands play
The most prolific play of the Nova-Scotia margin is the Valanginian to Hauterivian sands play. Production is concentrated in the Sable sub-basin along shelf edge delta sands. Similar play elements configuration could be encountered in the adjacent Huron sub-basin. For these sub-basins, traps are mainly growth fault related traps. Other prospective areas have been materialized in the Annapolis sub-basin associated with slope deposits (Annapolis G-24 gas discovery). Trap styles are structural (growth faults related traps, toe thrust folds and turtle back structures) and stratigraphic (flank pinch-out and diapir overhang in pound-basins). A possible turbiditic sands play fairway exists in zones 4 and 6 in water depth exceeding 2000 m.
Barremian sands play
Production exists in the Barremian sands of the Sable sub-basin (Zone 3). The prospective area could extend towards the adjacent Huron sub-basin (Zone 5) along the shelf deltaic sands and towards the Annapolis sub-basin in the slope sands play fairway. Trap styles are structural (growth faults related traps, toe thrust anticlines and turtle back structures) and stratigraphic (pound-basins). A possible turbiditic sands play fairway exist in zones 4 and 6 in water depth exceeding 2000 m.
Albian sands play
The most prospective is located in the Sable sub-basin (discoveries) and Huron sub-basins for the shelf deltaic sands and in the Annapolis sub-basin for the slope sands. A possible turbiditic sands play fairway exist in zones 2, 4 and 6 in water depth exceeding 2000 m. Trap styles are structural (growth faults related traps and toe thrust anticlines) and stratigraphic (pound-basins).
Late Albian "lowstand" sands play
The most prospective area is located along a narrow band which highlight the paleo-shelf break of the delta. Even if slope sands have been encountered in the Tantallon M-41 well, the "lowstand" sands play has not be proven yet. Trap styles are structural (growth fault related traps) and stratigraphic ("lowstand" type entrapment).

Chapter 8-3 called "Event Charts" summarizes the age of the essential elements and processes, the preservation time and the critical moment in the form of event charts.
Traps
Traps were formed from Early Jurassic to present times. On the shelf and slope area (zones 1, 3 and 5), most of the traps developed between Early Jurassic and Eocene times. In zones 3 and 5, most of the traps are growth fault related traps. Younger traps are mainly related to salt diapirism.
Growth faults related traps (zones 3 and 5) mainly formed from Mid-Jurassic to Early Cretaceous (before the peak of hydrocarbon generation) even if the faults remain active up to Eocene times. Younger traps could have occurred later than the main generation and migration of hydrocarbons.
Petroleum systems
The peak of hydrocarbon generation always occurred later than the deposition of reservoir and seal rocks.
In zone 1, a continuous slope failure (bypass, erosion, gliding) occurred during Cretaceous and Early Tertiary times with a paroxysm event dated Ypresian time (Montagnais event). This process implies reduced sealing effectiveness for the Jurassic Carbonate play.
In zone 1, the petroleum system completely depends on the Early Jurassic source rock presence.
In zones 3 and 5, all the elements and processes are present. The petroleum systems have crossed their hydrocarbon peak generation.

Chapter 8-4 deals with **Hydrocarbon volumes** in place for each play system

CHAPTER 8-1

PETROLEUM EVALUATION

STRUCTURAL PROVINCES AND TRAPS

PETROLEUM EVALUATION - STRUCTURAL PROVINCES AND TRAPS

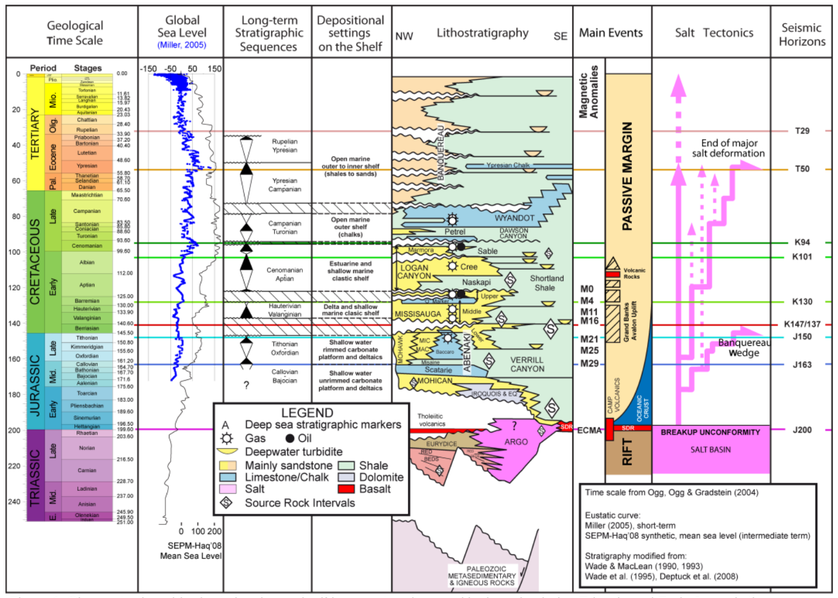


Figure 1: Chronostratigraphic chart showing main rifting event and evaporitic deposits during Triassic and Early Jurassic times

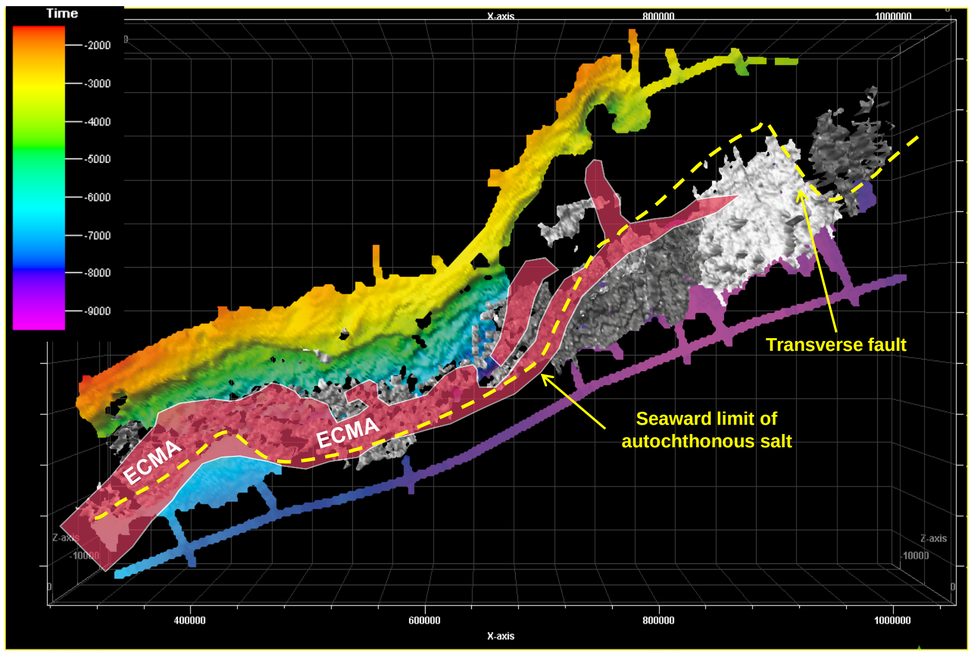


Figure 3: Top Jurassic time structural map (color coded) combined with salt structural map (grey) and ECMA location (transparent red)

During Triassic-Early Jurassic times, rifting related faults created NE-SW elongated horst and graben systems filled by clastic sediments on the shelf area (Figure 1 and 2) (Tankard, and Balkwill, 1989 , Welsink et al. 1989) : in the Orpheus sub–basin and along the paleo-slope area, these faults bound a deep almost continuous salt basin. The Northwestern boundary of the salt basin is generally controlled by normal faults or pinch-out of the evaporitic sequence. The Southeastern boundary seems also controlled by a normal fault system separating seaward dipping reflectors (when observed) from salt deposits. This Southeastern boundary coincides with the ECMA (East Coast Magnetic Anomaly, Dehler ,2010)(Figure 3).

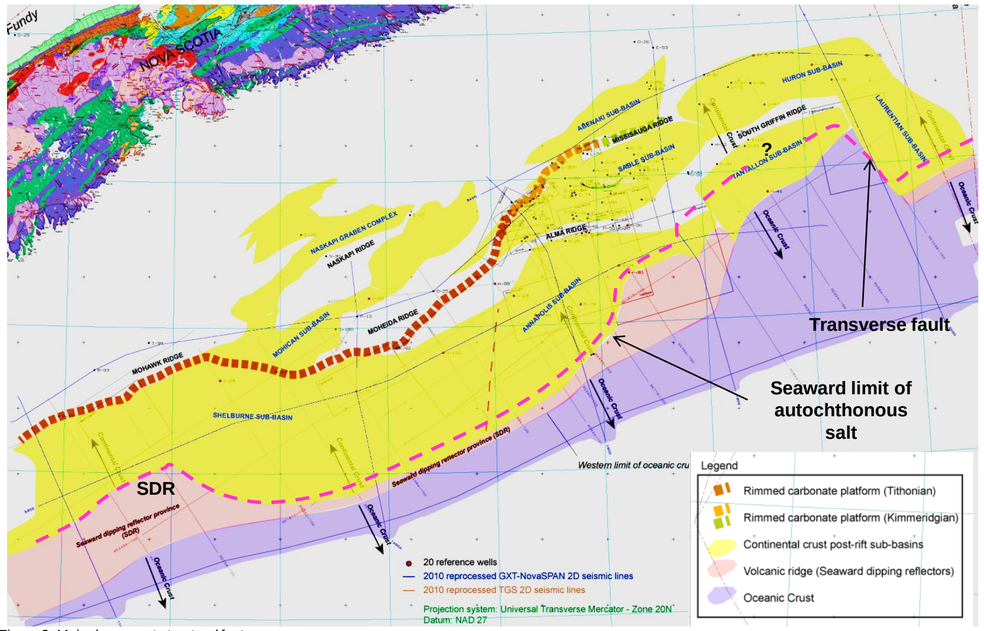


Figure 2: Major basement structural features

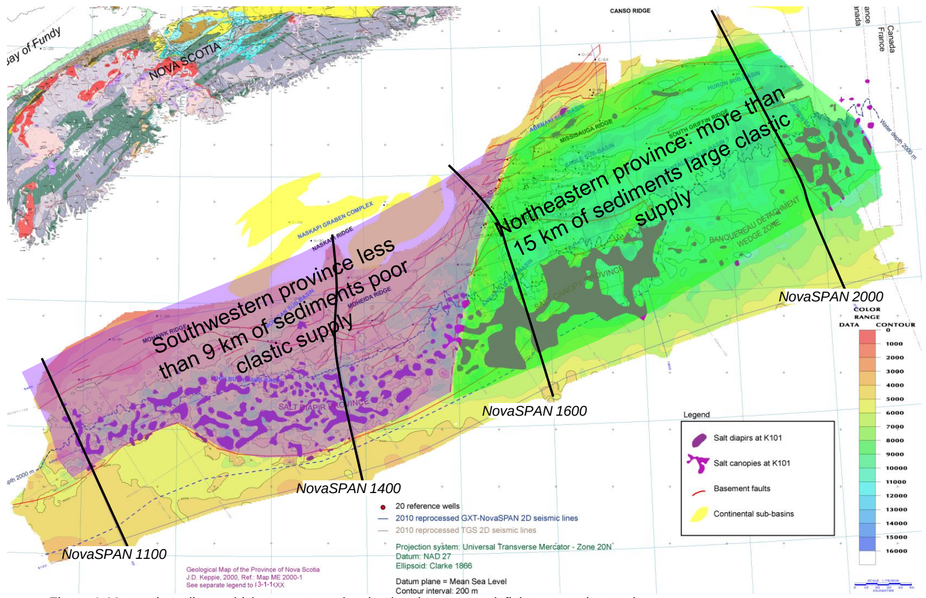


Figure 4: Mesozoic sediment thickness map and salt related structures defining two major provinces

The Seaward limit of the autochthonous salt mimics the Jurassic paleo-shelf (Figure 3) suggesting a direct control of the autochthonous salt on the Mesozoic basin architecture. In the Northern part of the margin, the large clastic sedimentary input and loading during Jurassic and Cretaceous times, pushed seaward the autochthonous salt and expelled it from its original basin inducing salt tongues, canopies and large gliding structures (Banquereau Syn-kinematic Wedge). On the contrary, the relatively reduced sediment input in the southern part of the margin favored the development of classical, vertically growing, diapirs. The contrast in sedimentary supply directly controlled the architecture of the margin and related traps. Two major provinces can be distinguished:

the Southwestern province with less than 9 km of sediments, where traps are related with diapirs and associated mini-basins

the Northeastern province with more than 15 km of sediments, where traps are much more complex and related with allochthonous salt (detachment, rollover, salt tongue, canopy, turtle-back; …)

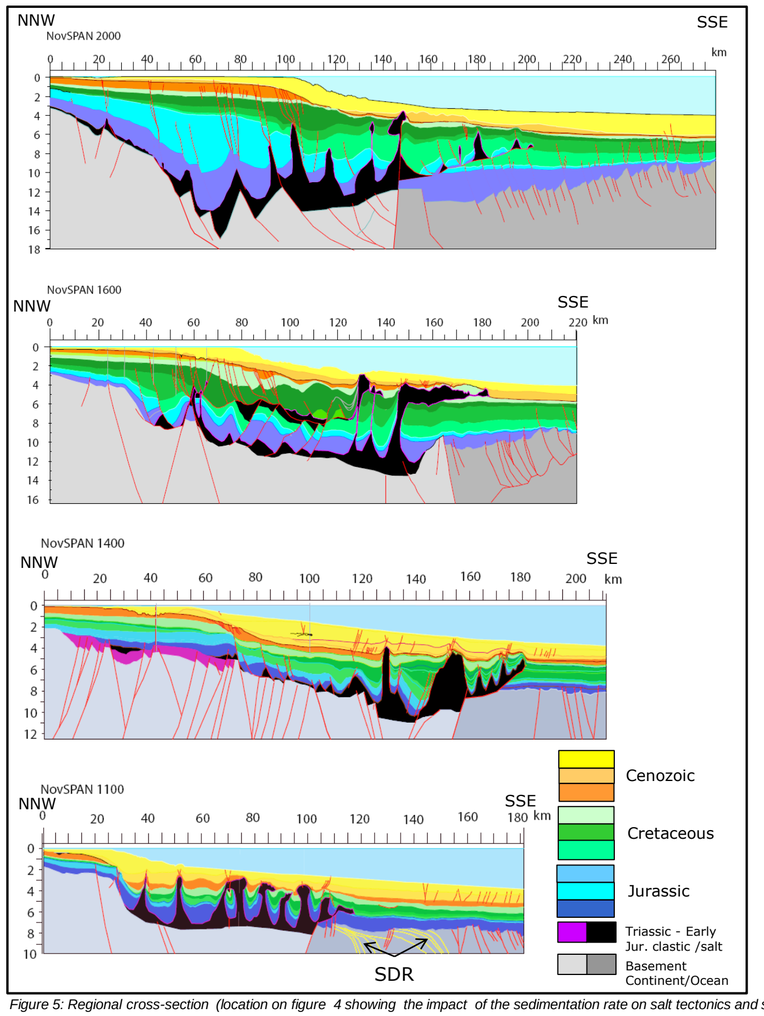


Figure 5: Regional cross-section (location on figure 4 showing the impact of the sedimentation rate on salt tectonics and structural style .

The four cross-sections of figure 5 illustrate the large changes in sedimentary thickness and the contrasted structural styles from North East to South West.

✓NovaSPAN 2000 cross-section displays very thick Jurassic series in the NNW with 10 km maximum thickness below the present day shelf domain; Cretaceous depocenter was shift to the SSE with the development of the Early Cretaceous Banquerau Synkinematic Wedge and 5 km maximum thickness below the present day slope. Due to Jurassic and subsequent Cretaceous sedimentary loading, salt was pushed ocean ward.

✓NovaSPAN 1600 cross-section displays a 2 km thick Jurassic basin overlain by a 5 km thick Cretaceous series. Expulsion of the autochthonous salt from the present day shelf domain, induced large salt allochthonous “nappes” during early Cretaceous times that generated subsequent gliding structures on top of this allochthonous salt. During Late Cretaceous times salt tongues and canopies developed in the distal part of the margin. Listric faults and “turtle-back” associated to collapsed rim synclines are common structures of this domain.

✓NovaSPAN 1400 cross-section is in the southwestern province where total thickness of Mesozoic and Cenozoic sediments is less than 9 km; maximum Jurassic thickness corresponds to the paleoshelf platform where carbonate sedimentation prevailed. Salt structures are mainly vertical diapirs except at the southwestern boundary of the autochthonous salt basin where Cretaceous sediments pushed the salt ocean-ward, forming a “ramping-up salt tongue”.

✓NovaSPAN 1100 cross-section displays the starving part of the margin (Shelburne sub-basin) where Mesozoic sediments are less than 4 km thick . Salt structures are mainly vertical diapirs generating numerous “mini-basins” where clastic sediments could have been trapped. A short salt tongue developed at the southwestern limit of the autochthonous salt basin. Autochthonous salt basin was bounded by a down to the northwest normal fault separating continental basement from a volcanic basement characterized by Seaward Dipping Reflectors (SDR)

As already discussed by Shimeld (2004) and Albertz et al. (2010) the slope domain of the Nova Scotia margin can be subdivided in various sub-provinces regarding the structural style. Four sub-provinces where distinguished on the basis of structural style and salt related traps (Figure 7):

- The Laurentian province characterized by numerous diapirs and canopies developed on the autochthonous salt basin . This province was poorly imaged by the seismic data available for this study and is not discussed in detail; it seems to be bounded to the Southwest by a large transverse fault offsetting the south western boundary of the autochthonous salt basin (see figure 3).
- The Banquerau Syn-kinematic Wedge province already described in detail by Ings and Shimeld (2006)
- The Canopy province characterized by autochthonous and allochthonous salt bodies and large canopy structures; This province was described in detail by Deptuck et al; 2009, 2010 a, b)
- The Diapir province mainly characterized by vertically raised diapirs on top of the autochthonous salt basin with local salt tongues at the southwestern limit of the autochthonous salt basin. (Deptuck et al. 2010)

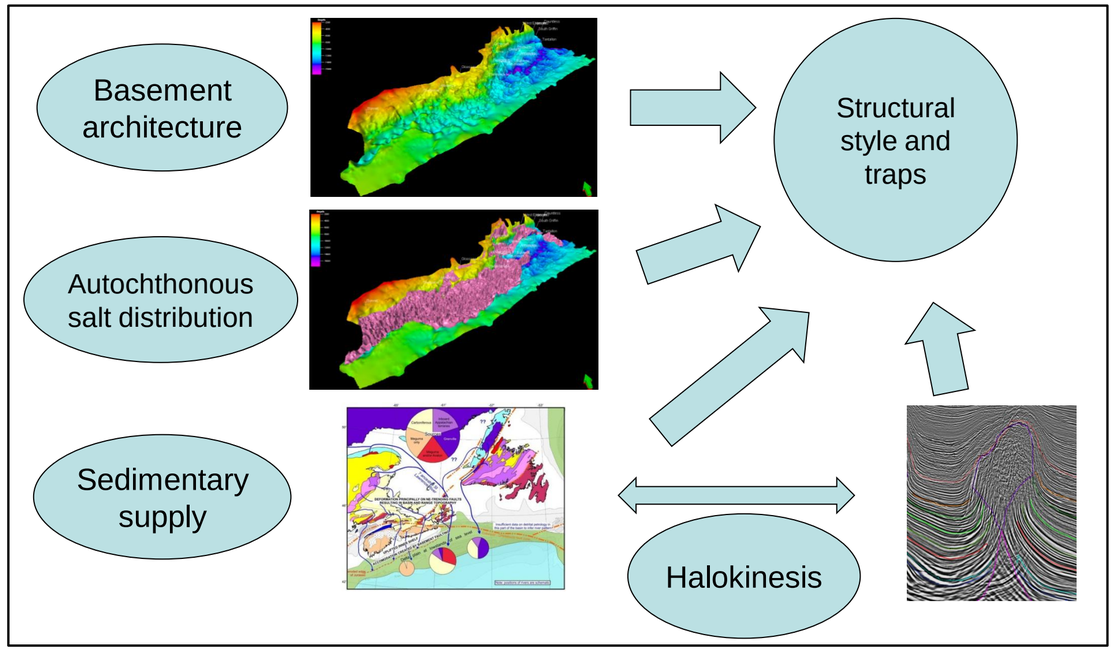


Figure 6: Key factors in structural style and traps definition

Structural style and traps can be genetically related to the combination of a reduced number of key parameters:

- Basement architecture : the rifting phase created NE-SW oriented horst and graben systems that controlled the deposition of Triassic early Cretaceous salt and clastic sediments. Basement tilted blocks of the continental domain generally associated to passive margin are poorly imaged along the Nova Scotia slope. South eastern limit of the salt basin occurred along a set of down to the NW normal faults.
- Autochthonous salt distribution : Due to its low density at depth and its relatively low effective viscosity (10^{17} Pa.s, Mukherjee et al. 2010), Triassic–Early Jurassic salt will deform easily under sedimentary loading. Differential sediment loading and buoyancy forces will favor salt movement and salt distribution and thickness will directly control the Mesozoic basin formation (subsidence related to salt withdrawal) and structures (listric faults, rollover, …). Large volume of salt suggests 2 to 4 km deep salt basin
- Sedimentary supply : Sediments deposited on top of salt basins produces differential loading and subsidence by expelling salt from its autochthonous basin. Major sedimentary supply induces major subsidence and maximum burial depending on the initial salt basin thickness.
- Halokinesis which is mainly driven by buoyancy forces is directly dependent upon volume of salt and sedimentation rate. Low sedimentation rate will allow vertical growth of diapir (Shelburne sub-basin) while high sedimentation rate and differential loading will favor oblique salt structures and salt motion from higher stress zone to lower stress zone.

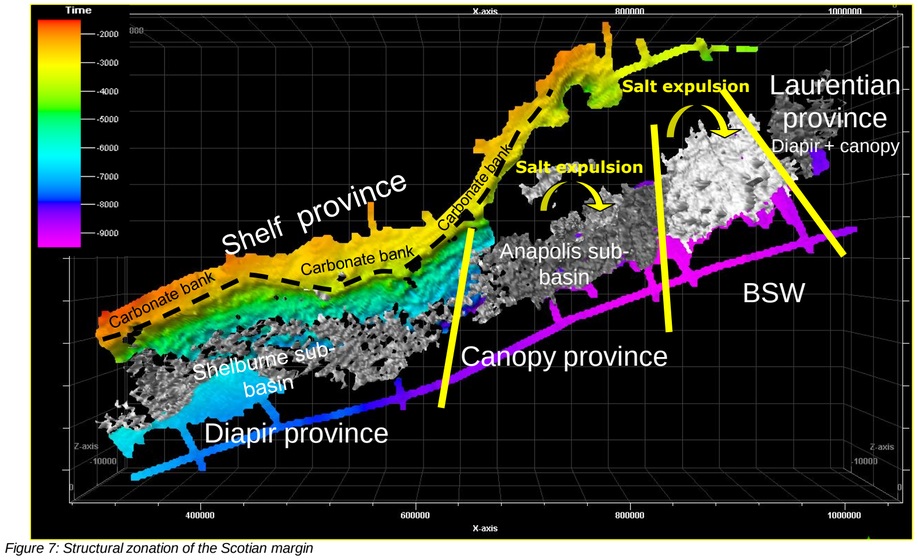


Figure 7: Structural zonation of the Scotian margin

PETROLEUM EVALUATION - STRUCTURAL PROVINCES AND TRAPS

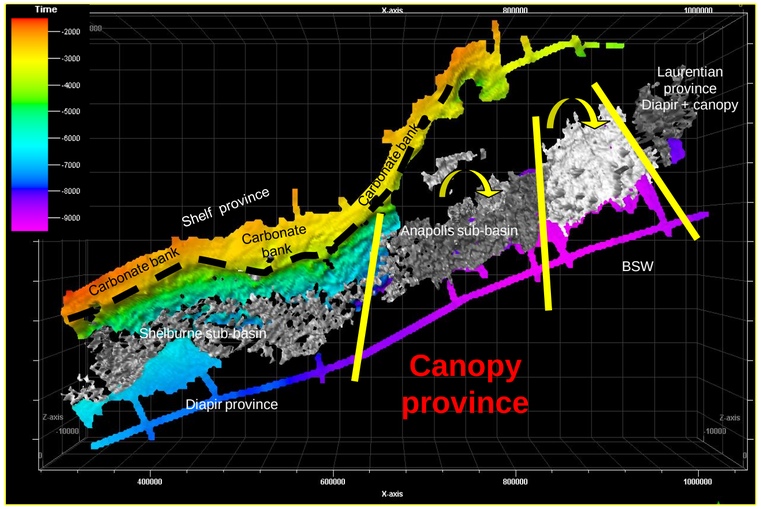


Figure 1: Scotian Margin Zonation

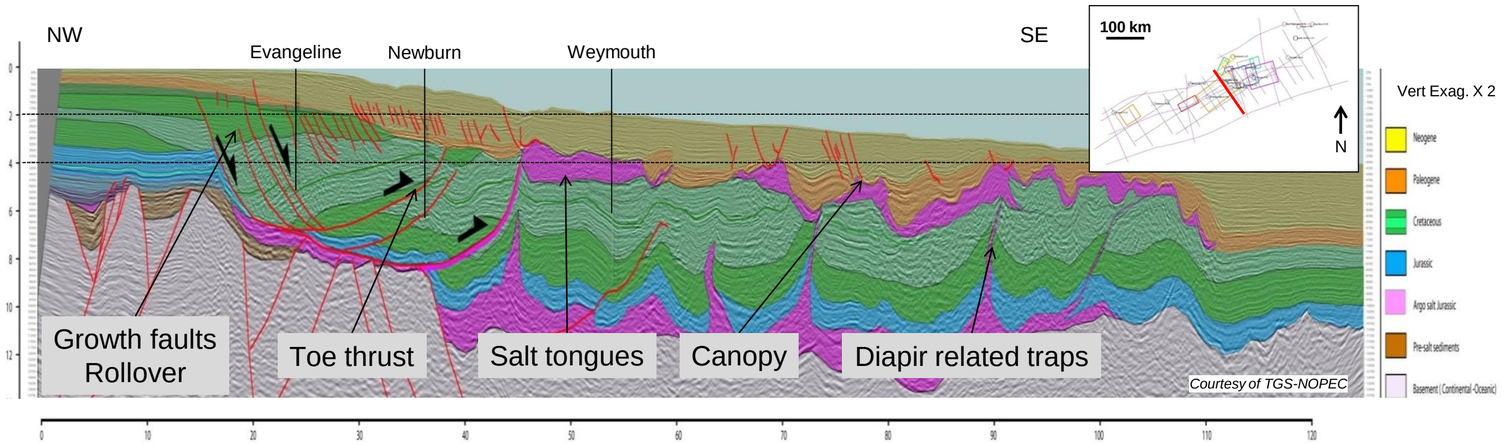


Figure 3: Canopy Province Associated Traps - Evangeline/Newburn/Weymouth Depth Section - 2010 reprocessed TGS 644-100

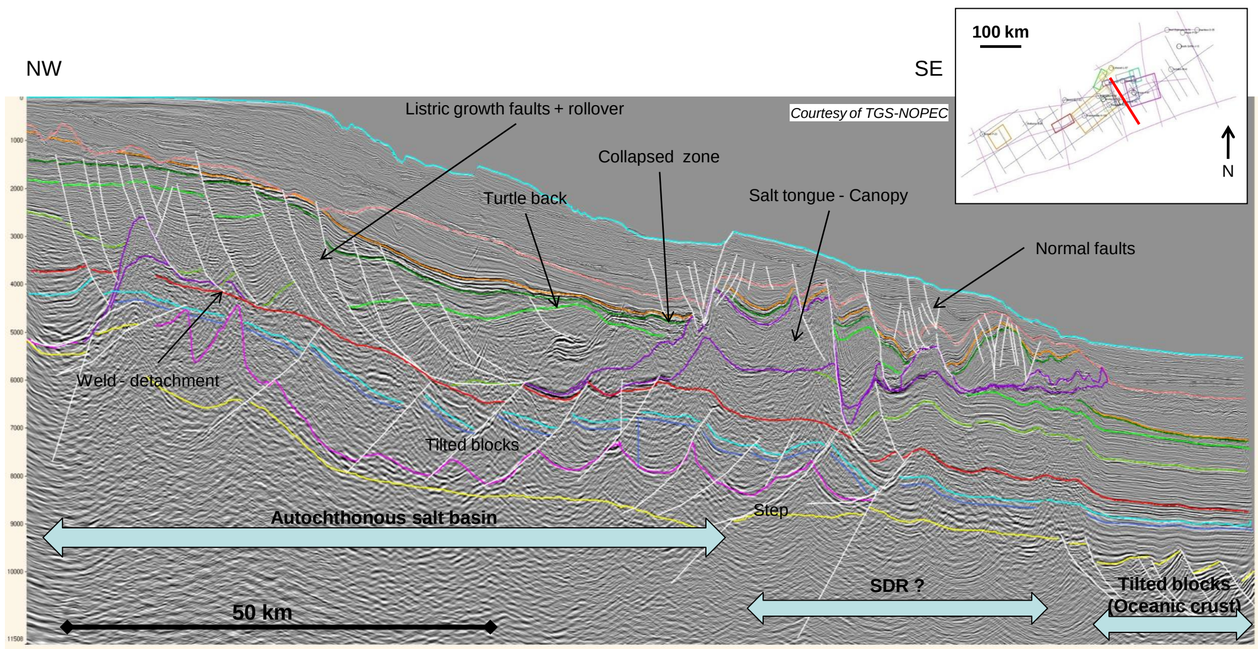


Figure 2: Canopy Province Strucural Style - Seismic 2D line - 2010 reprocessed TGS Line 716-109

Seabed
T29
T50
K94
K101
K130
K137
J150
J163
Allochthonous Salt
Autochthonous Salt
Post Rift Base

Well	Age	Salt diapir	Rollover	Drape structure	Carbonate Bank
Alma	Cretaceous (Missisauga)		Rollover		
Arcadia	Late Jurassic MicMac		Rollover		
Banquereau	Cretaceous		Rollover		
Chebucto	Cretaceous		Rollover		
Citnalta	Late Jurassic MicMac		Rollover		
Cohasset	Cretaceous			Drape structure	
Glenelg	Cretaceous		Rollover		
Intrepid	Cretaceous		Rollover		
North-Triumph	Cretaceous		Rollover		
Olympia	Cretaceous		Rollover		
Onondaga	Cretaceous	Salt diapir			
Panuke	Cretaceous			Drape structure	
Primrose	Cretaceous/Jurassic	Salt diapir			
South Sable	Cretaceous		Rollover		
South Venture	Cretaceous		Rollover		
Thebaud	Cretaceous		Rollover		
Uniacke	Jurassic		Rollover		
Venture	Cretaceous/Jurassic		Rollover		
West Olympia	Cretaceous		Rollover		
West Sable	Cretaceous	Salt diapir			
West Venture C-62	Cretaceous/Jurassic		Rollover		
West Venture N-91	Cretaceous		Rollover		
Deep Panuke	Jurassic				Carbonate Bank

Table1: Proven Structural Traps

This structural province correspond to the productive zone of the Sable basin. It is characterized by complex salt structures with locally a “roho” system with two salt bodies (Rowan et al. 1999):

the basal autochtonous salt on top of which Jurassic to early Cretaceous series were faulted and tilted

the upper allochtonous salt body expelled from the Sable basin area and squeezed ocean ward by Cretaceous deltaic deposits**.** This uppermost salt forms large canopies locally connected by several feeders to the autochthonous salt (true canopies). In the Sable basin area the uppermost salt has been almost completely expelled from its original province and only connected by remnant weld feeders (Deptuck et al, 2009, Deptuck, 2010 a, 2010b, Kendell and Deptuck, 2010);

Updip, in the shelf and shelf break area, the structure is controlled by listric fault rooted either in the basal autochthonous salt or in the uppermost salt body. The associated rollover anticlines constitute the most productive traps of this area. As shown in table 1, 75 % of the HC discoveries are related to rollover or / growth faults structures and 95% of the reservoirs are sand (mainly Cretaceous in age).

Contractional structures (toe thrust) are observe in the uppermost part of the slope (figure 3, Deptuck et al. 2009) but most of the structures are extensional and related with gravitational deformation, salt collapse or withdrawal : growth roller faults, rollover, tilted blocks, turtle back. In their distal part the base of the salt canopies form a ramp cutting up the Upper Cretaceous and Tertiary series suggesting syn-sedimentary gliding. Lack of contractional structure in the deep basin part of the margin (genuine toe thrust) suggests an open end system as described for the Banquereau Syn-kinematic Wedge by Ings and Shimeld (2004). The most distal canopies and salt tongues override the Continent Ocean transition zone (possible volcanic SDR domain).

In map view, the extension of the listric growth fault domain is directly controlled by the SW-NE to SSW-NNE inflection of the Jurassic carbonate bank which is itself directly controlled by the autochthonous salt basin geometry (Figure . 2,3, 4 _ Plate 8-1-1-a)

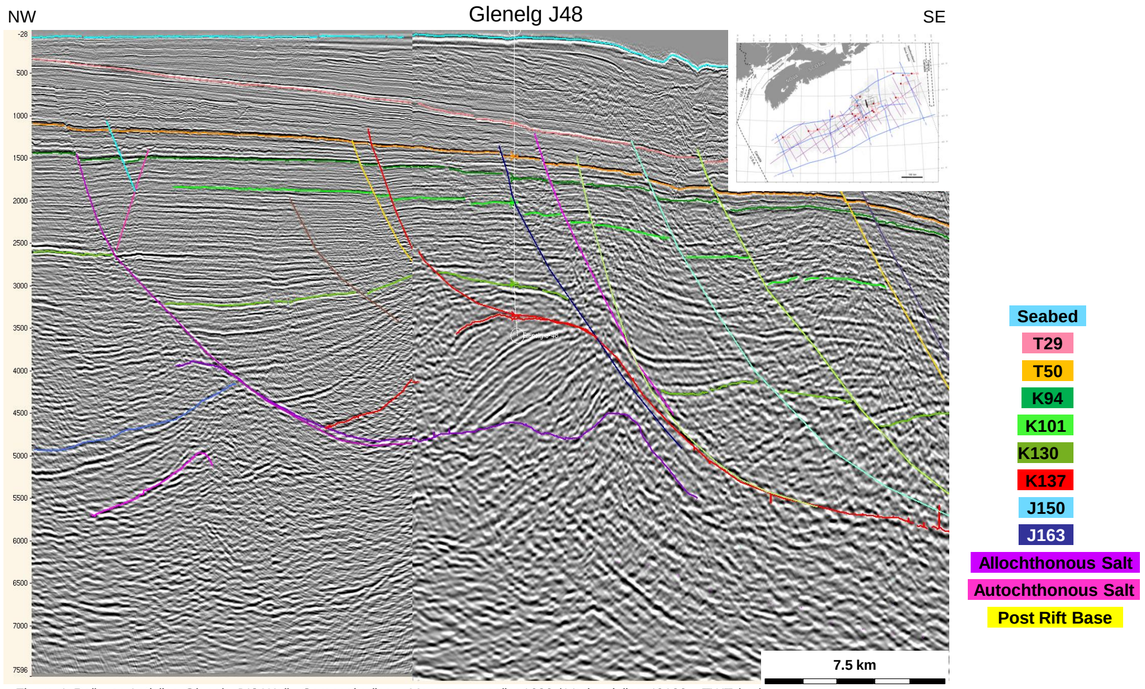


Figure 4: Rollover Anticline Glenelg J48 Well - Composite line – Marmora crossline1600 / Veritas inline 40100 – TWT (ms)

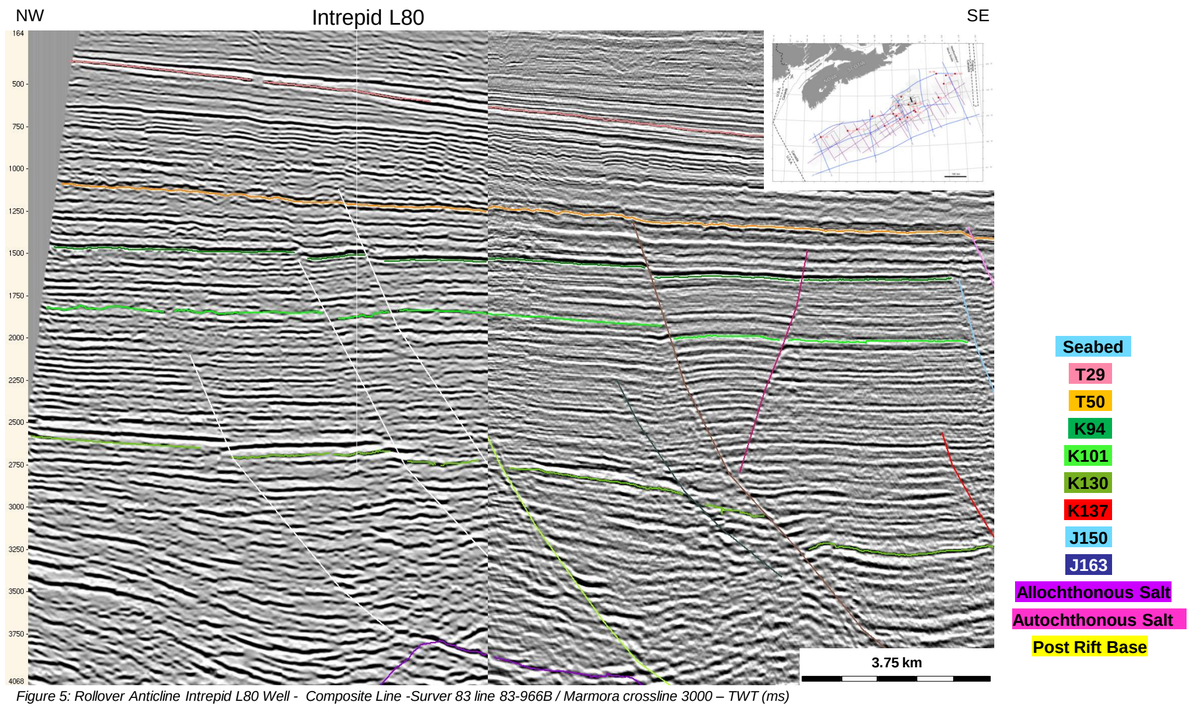
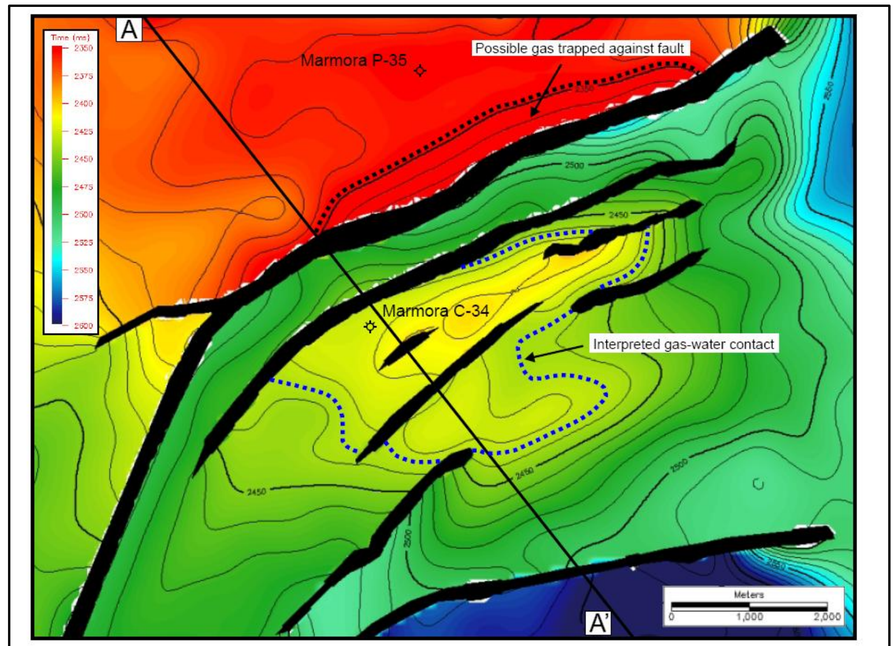
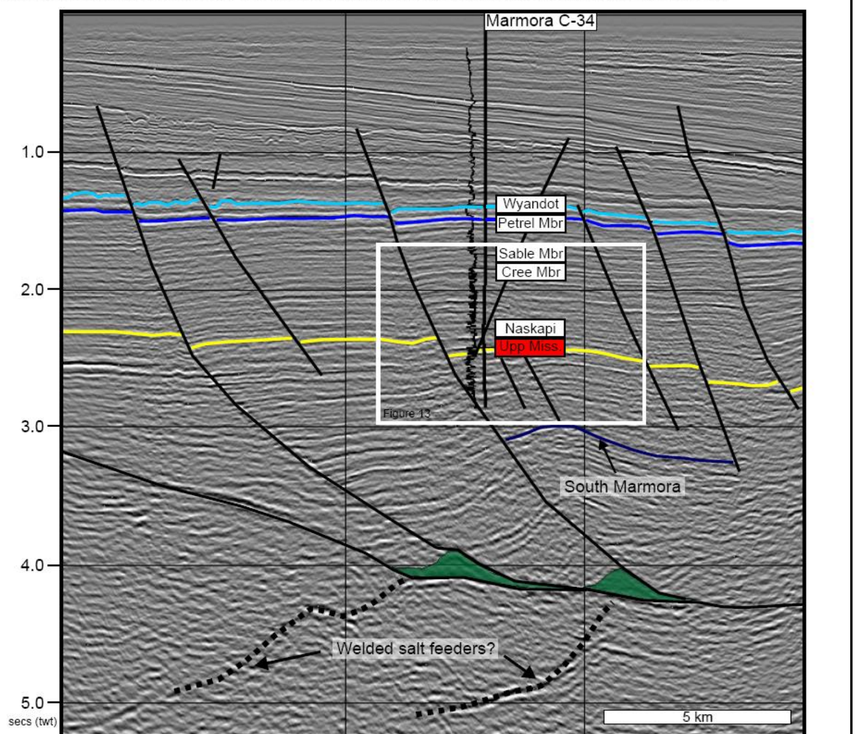


Figure 5: Rollover Anticline Intrepid L80 Well - Composite Line -Surver 83 line 83-966B / Marmora crossline 3000 – TWT (ms)

The Marmora pool geometry shown in Figure 6 with an interpreted gas water contact tangent to the roller listric fault suggests that faults are non-sealing, at least at the time scale of entrapment processes. Moreover footwall blocks “crests”, which are the most prospective targets in extensional provinces (ie. in the North Sea), seem poorly prospective, in the Sable basin, suggesting also that faults are non-sealing. However this rule does not seem to be general in the Sable basin and the Intrepid accumulation constitutes an exception, with a potential seal along the bounding normal fault (Figure 5).



Structure map of the top Missisauga gas sand (Sand 1) encountered in the Marmora C-34 well. The interpreted gas-water contact is noted by the dashed blue line. The location of seismic profile A-A' is also shown.



Seismic dip line A-A' near Marmora C-34 (well is projected 150 meters). The upper Missisauga (yellow horizon) represents the pay sand (Sand 1). Salt rollers are shown in green and potential welded salt feeders are dashed black lines. The white inset box outlines an area of the seismic profile penetrated by Marmora C-34 that is shown in greater detail in figure 13. The gamma ray log is shown to the left of the borehole.

Figure 6: Growth faults and rollover structures - Extracts from Call for bids 2009-2010 CNSOPB

PETROLEUM EVALUATION - STRUCTURAL PROVINCES AND TRAPS

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

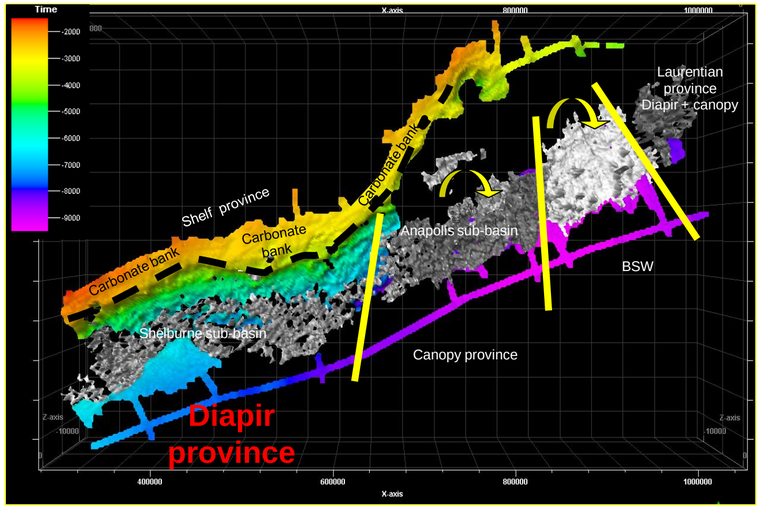


Figure 1: Scotian Margin Zonation

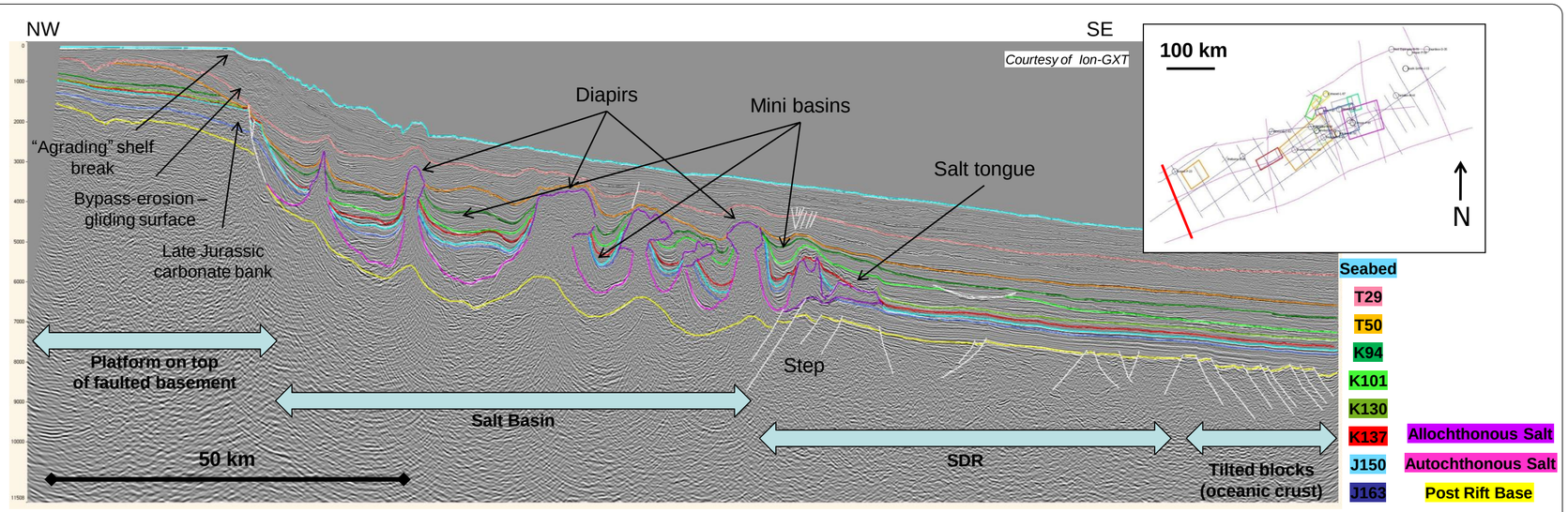


Figure 2: Diapir Province Strucural Style - Seismic 2D line - 2010 reprocessed GXT NovaSPAN 1100

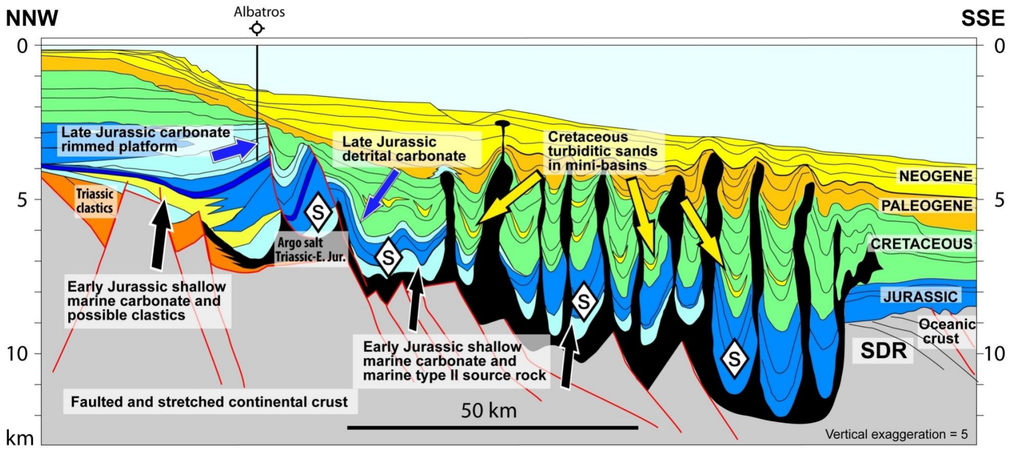


Figure 3: Diapir Province Plays

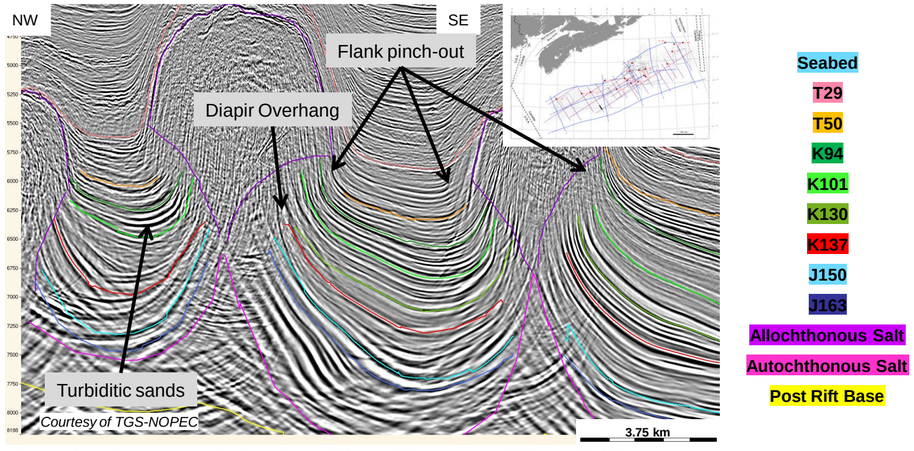


Figure 4: Diapir Province Associated Trap - Seismic 2D line - 2010 reprocessed TGS – line 408-100

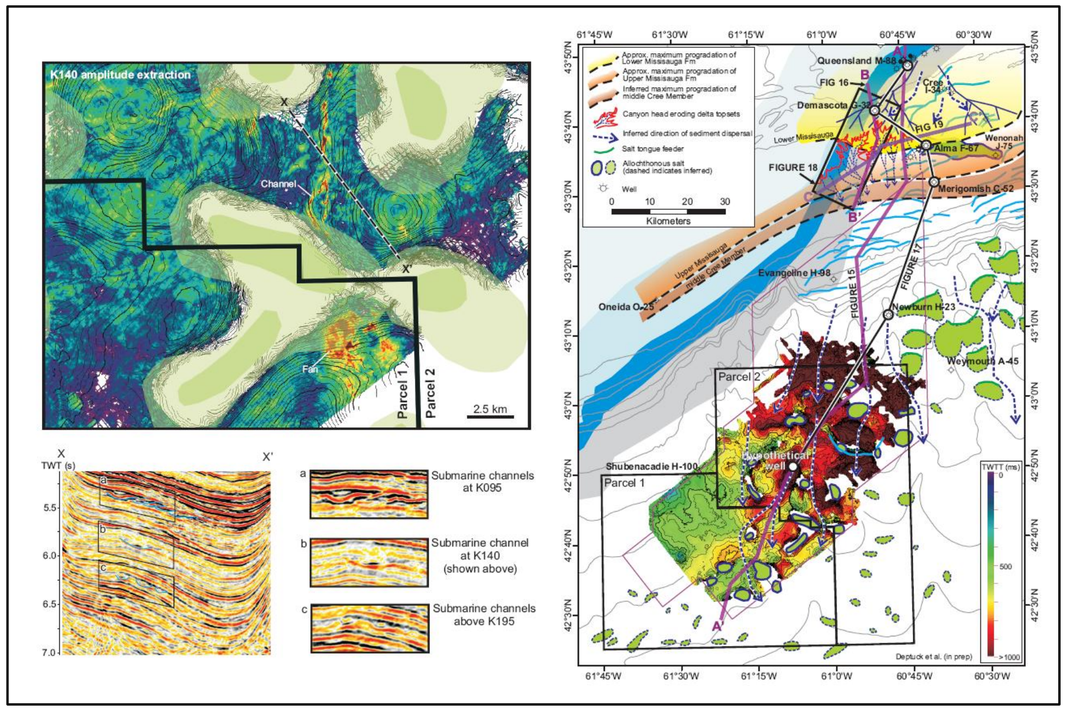


Figure 5: Diapir Province Associated Trap - Submarine Channels and Mini Basins - Extracts from Call for bids 2009-2010 CNSOPB, Deptuck et al. 2009

The diapir province (corresponding to structural subprovince I and II described by Shimeld 2004) is characterized by vertical circular diapirs or SW-NE elongated wall of salt directly connected to the autochthonous salt basin. As shown by growth sedimentary wedge in Jurassic series, salt was active very early during the margin evolution and continued to move up to Paleogene times. Few diapirs reached the sea bottom and salt activity was less active since Neogene times.

Spacing of salt walls or diapirs is variable but interpreted sections of Figure 2 and 3 indicate an average spacing of 5 to 10 km, Numerous "mini basins "(Rowan et al. ,1999) developed in between salt structures. Such mini basins constitute potential "trap" for "turbiditic transported sands (Deptuck et al. 2009, Albertao, 2010) (Figure 5) and are potential targets for further exploration.

Petroleum system in this province is define on the basis of an Early Jurassic source rock, analogue to the one found on the Moroccan, Portugal conjugate margin. This type II marine source rock could have generated liquid hydrocarbon with entrapment in the classical salt diapir related traps (overhang, flank pinch-out) or in sedimentary traps related with turbiditic sand in the mini basins (Figure 3 , 4 and 5).

PETROLEUM EVALUATION - STRUCTURAL PROVINCES AND TRAPS

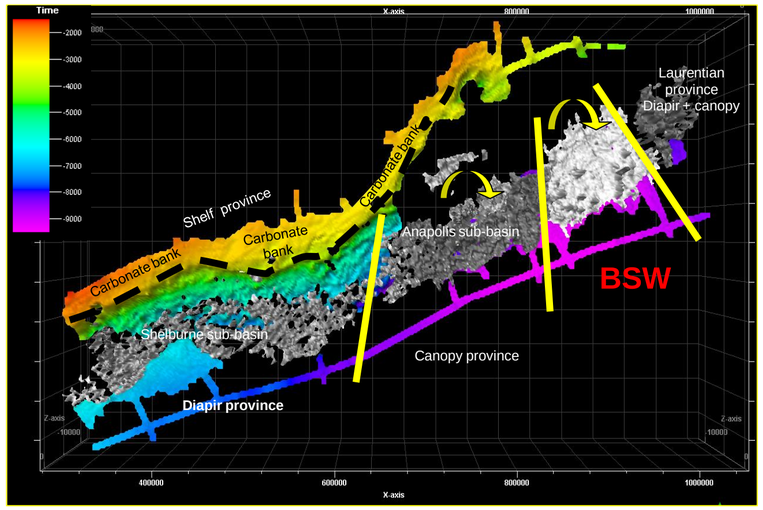


Figure 1: Scotian Margin Structural Zonation

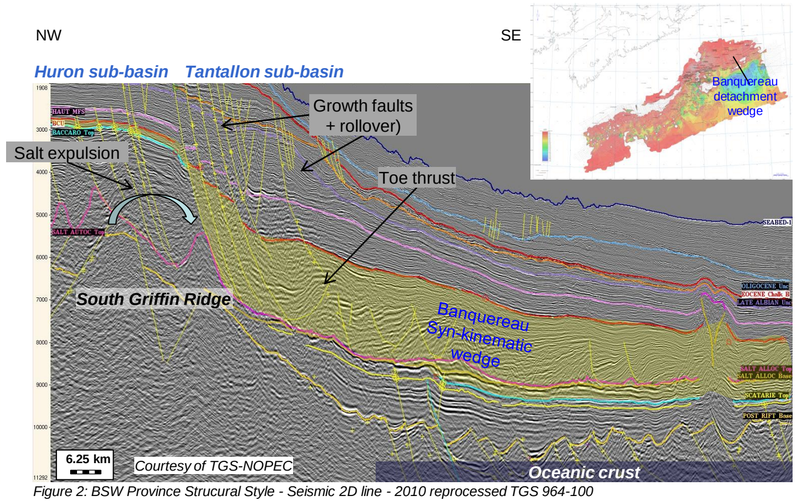


Figure 2: BSW Province Strucural Style - Seismic 2D line - 2010 reprocessed TGS 964-100

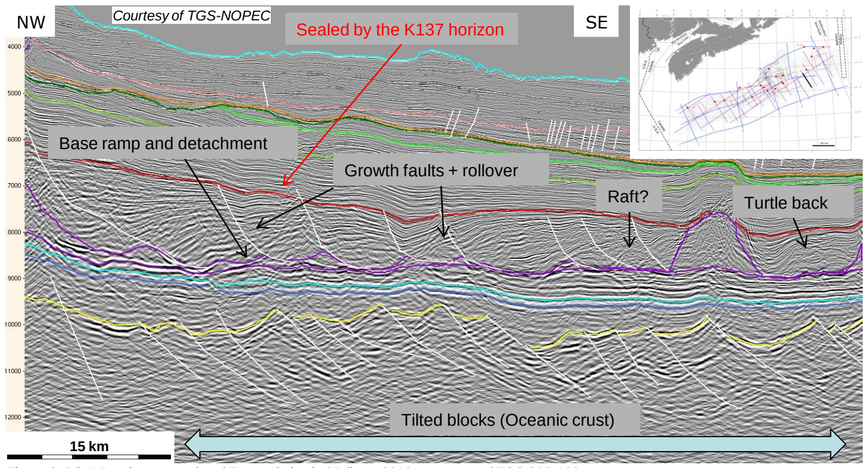


Figure 3: BSW Province Associated Traps- Seismic 2D line - 2010 reprocessed TGS 892-100

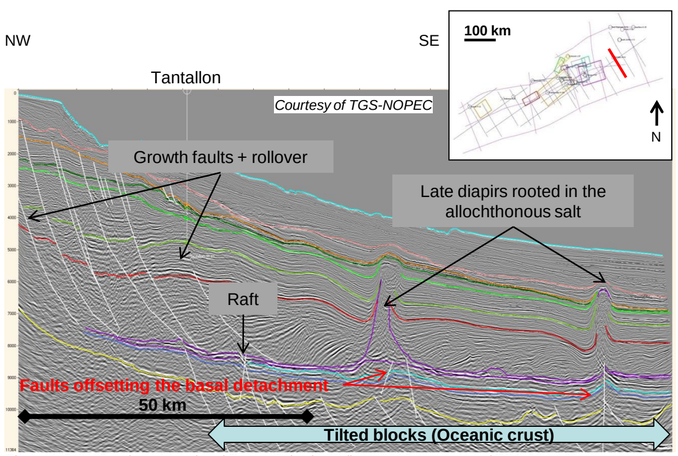


Figure 4: BSW Province Associated Traps- Seismic 2D line - 2010 reprocessed TGS 924-109

This province was described in detail by Ings and Shimeld (2004) . It is characterized by a very reduced number of piercing diapirs and a large Jurassic to Early Cretaceous landslide gliding on top of a an allochthonous salt tongue; The salt tongue is presently very thin (if still present) and resulted from the expulsion of salt from its original basin forming an advancing sole detachment during Jurassic and early Cretaceous times. Such a mechanism was illustrated by numerical modeling at Dalhousie university (Ings et al. 2009) Because the detachment toe was not confined when sedimentation occurred, updip, extension in the BSW is not balanced by downdip contraction. Syn-sedimentary gliding and transport can be estimated to be approximately 175 km ocean ward (Ings and Shimeld, 2004) and reached the oceanic domain overriding abyssal deposits resting on top of typical tilted blocks of oceanic crust.

Due to the open end mechanism (Ings and Shimeld, 2004) most of the structures are extensional and consist of growth listric roller faults, rollover, turtle-back, and possible “rafts” of isolated Jurassic blocks (figures 2, 3, 4). Locally, small contractional “toe thrust” can be observed in the upper part of the Banquereau wedge (Figure 2).

The whole structure is sealed by Valanginian sediments; At the periphery of this large gliding wedge few vertically raised diapirs can be observed (figure 4). They are issued from the allochthonous salt tongue and seem to have been caused by Cenozoic faults offsetting the sole detachment (Figure 4).

Due to water depth and sedimentary thickness , no one of these Jurassic to early Cretaceous structures was recognize by exploratory wells.

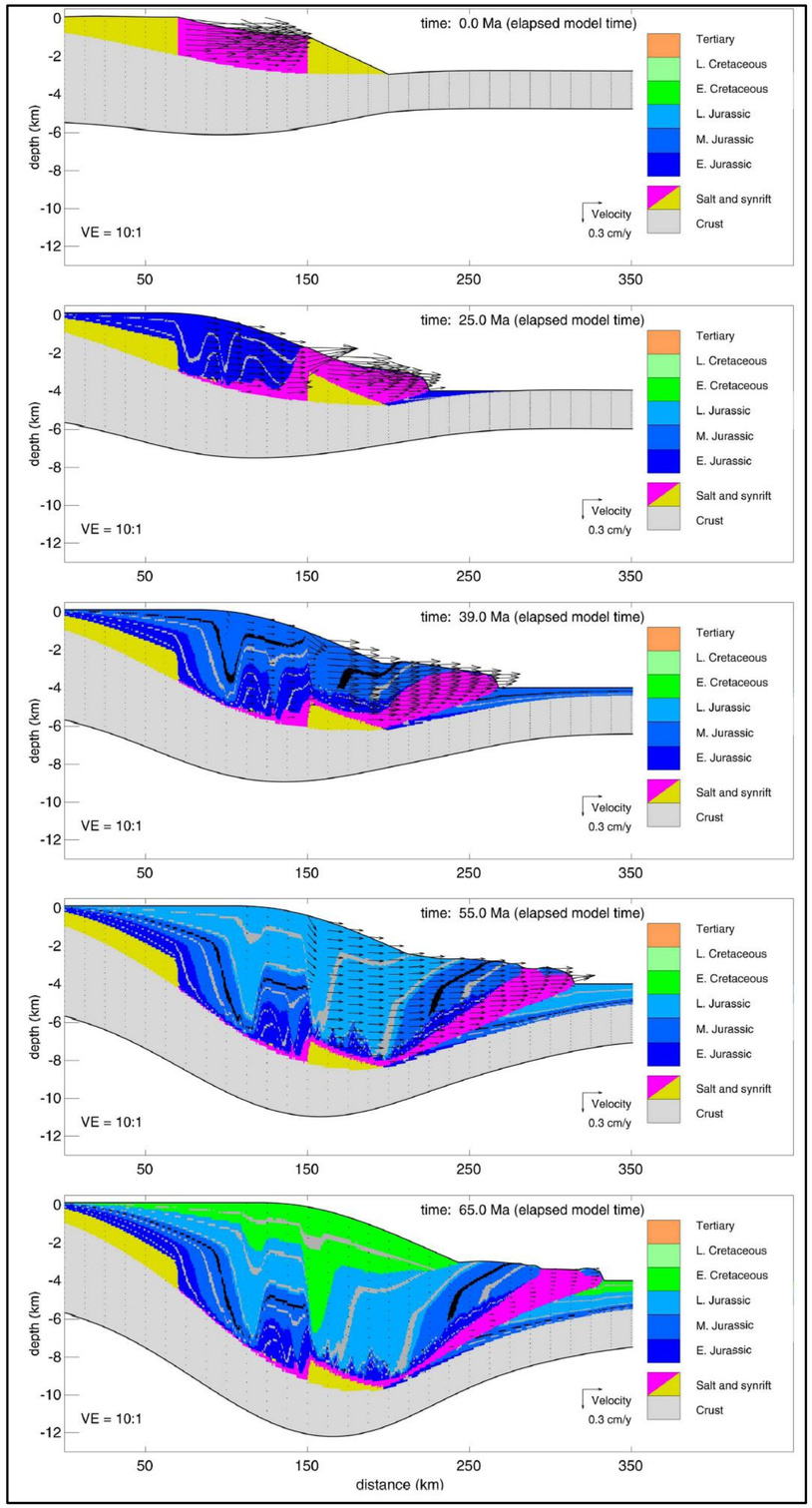


Figure 5: Numerical Simulation of the Syn-kinematic Banquereau Wedge, After Steven Ings et al., 2009. Forward Modellling of Salt Tectonics.
http://www.offshoreenergyresearch.ca/Portals/

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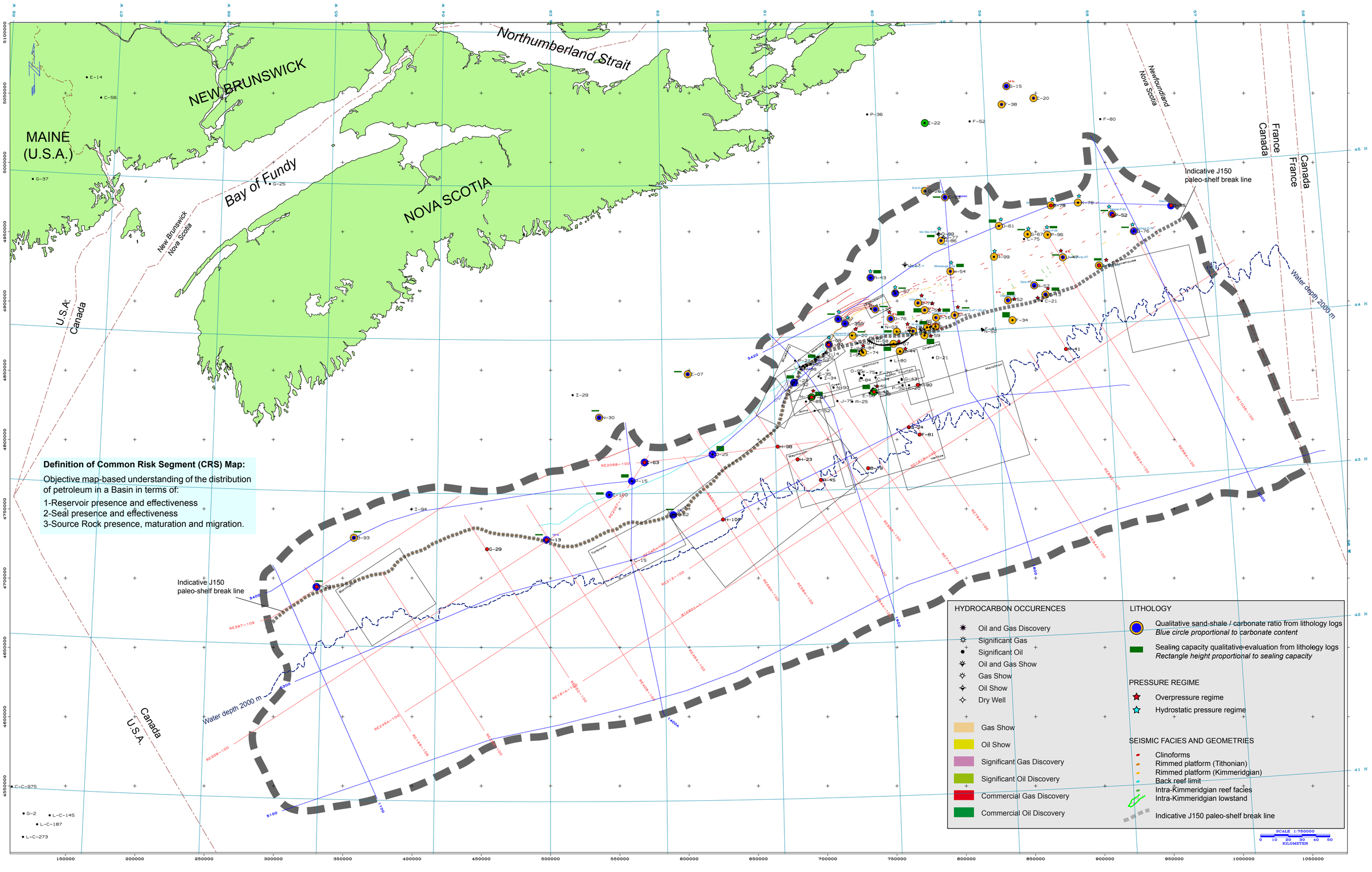
CHAPTER 8-2

PETROLEUM EVALUATION

COMMON RISK SEGMENT (CRS) MAPPING

PETROLEUM EVALUATION - CRS MAPPING

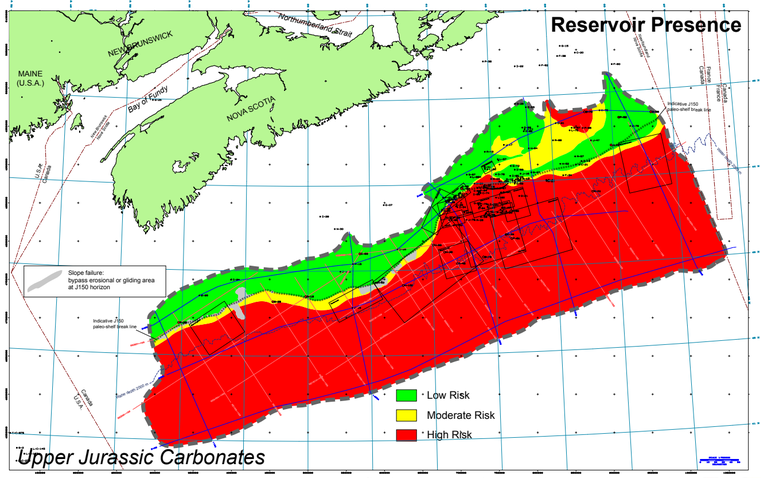
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



PL. 8-2-1 **Upper Jurassic Sands and Carbonates - CRS Mapping - Well and Seismic Data**

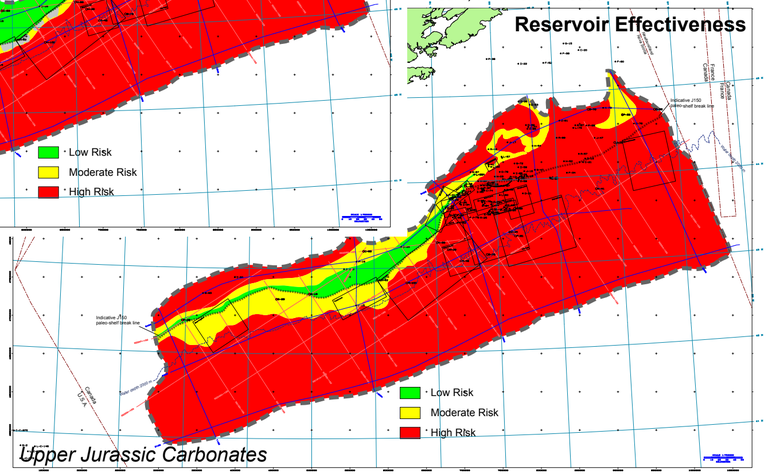
PETROLEUM EVALUATION - CRS MAPPING

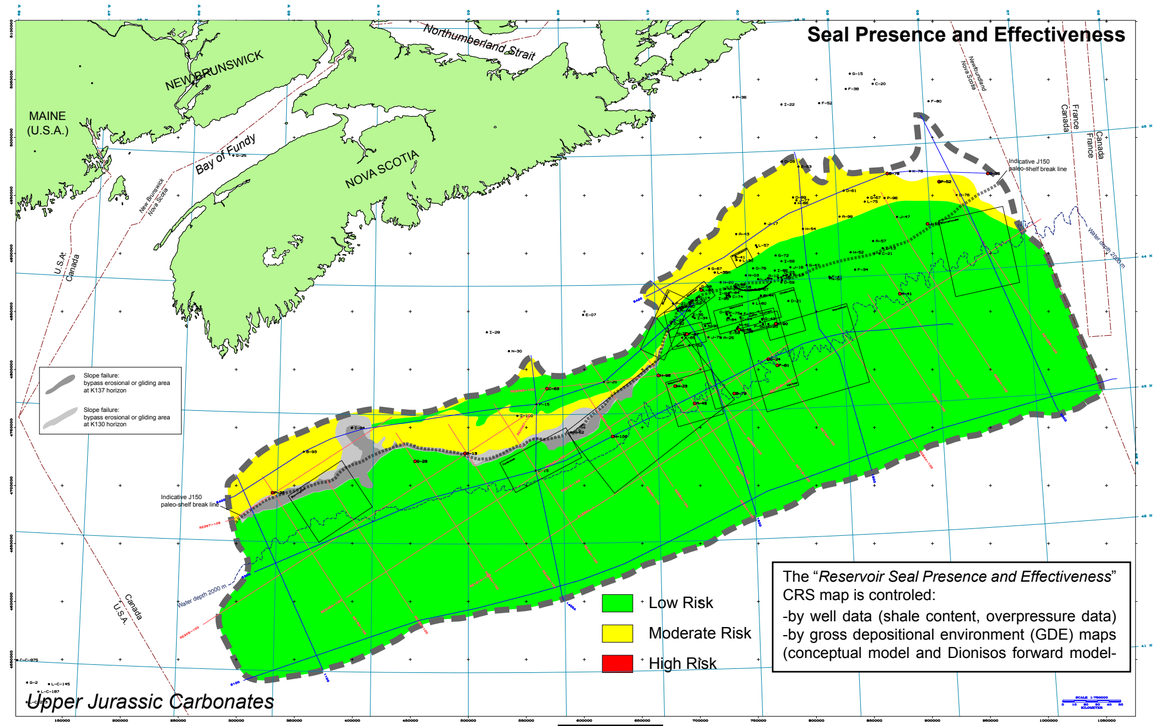
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



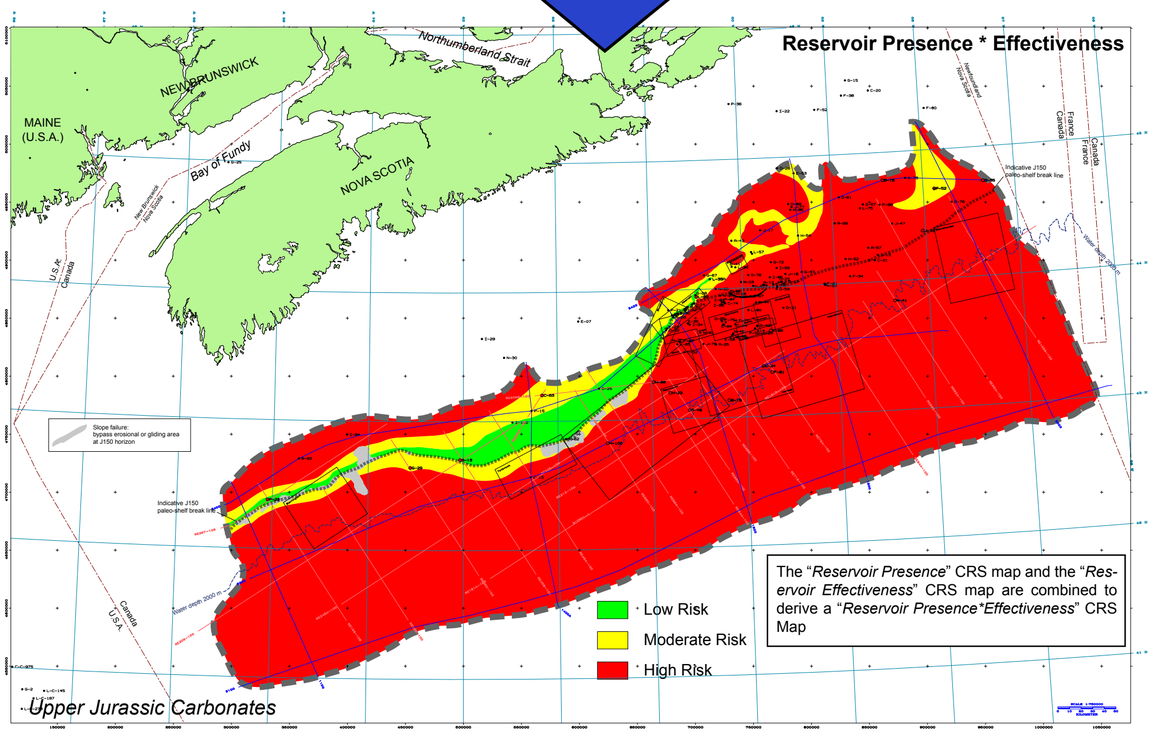
The "*Reservoir Presence*" CRS map is controled by:
-well data (qualitative carbonate content),
-seismic data (seismic facies and geometries),
-gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).

The "*Reservoir Effectiveness*" CRS map is controled by well data (porosity values) and by porosity prediction (compaction and overpressure) from Temis model.

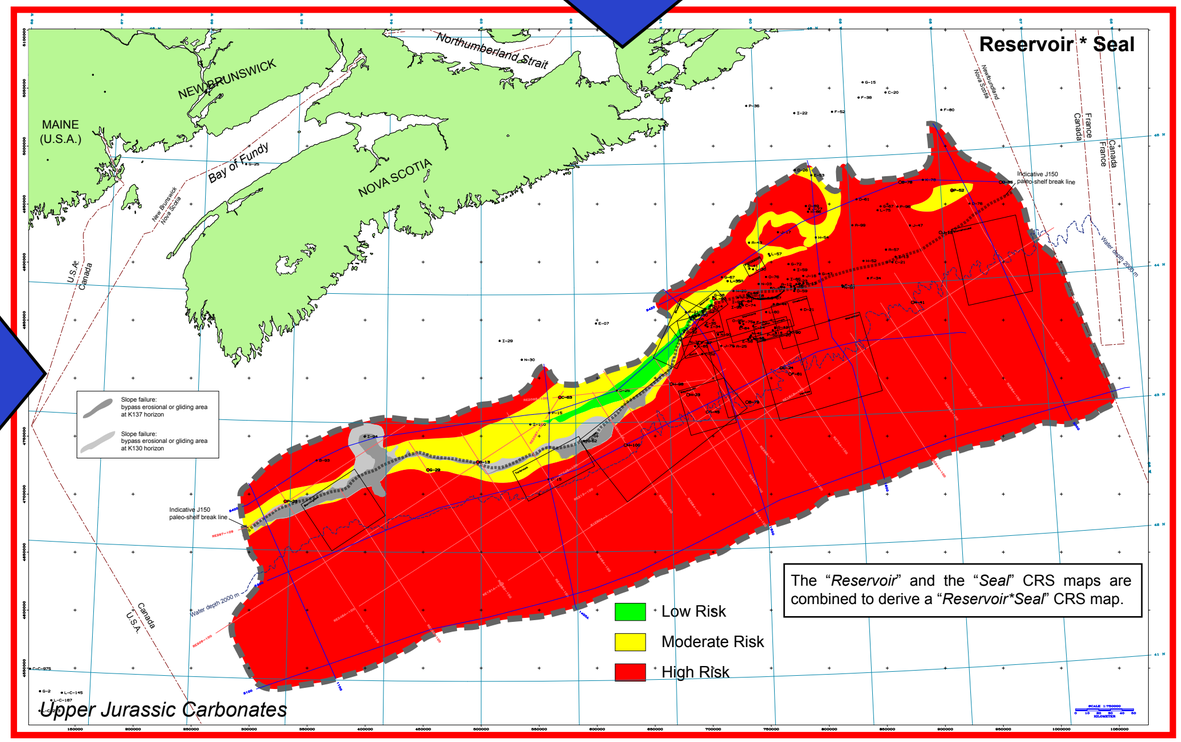




The "*Reservoir Seal Presence and Effectiveness*" CRS map is controled:
-by well data (shale content, overpressure data)
-by gross depositional environment (GDE) maps (conceptual model and Dionisos forward model-



The "*Reservoir Presence*" CRS map and the "*Reservoir Effectiveness*" CRS map are combined to derive a "*Reservoir Presence*Effectiveness*" CRS Map



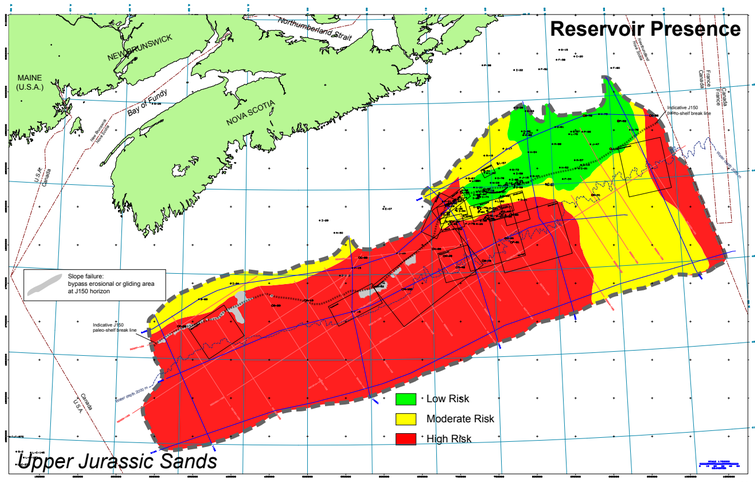
The "*Reservoir*" and the "*Seal*" CRS maps are combined to derive a "*Reservoir*Seal*" CRS map.

Upper Jurassic Carbonates - CRS Mapping - Reservoir and Seal

PL. 8-2-2

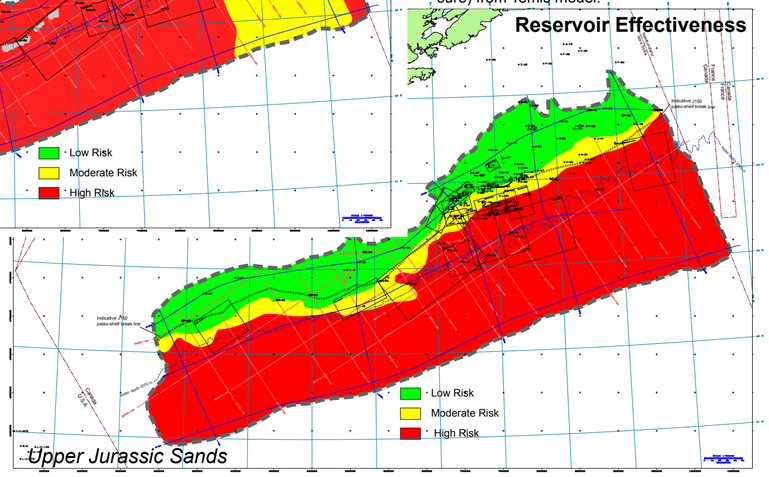
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



The "*Reservoir Presence*" CRS map is controled by:
-well data (qualitative sand-shale / carbonate ratio),
-seismic data (seismic facies and geometries),
-gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).

The "*Reservoir Effectiveness*" CRS map is controled by well data (porosity values) and by porosity prediction (compaction and overpressure) from Temis model.



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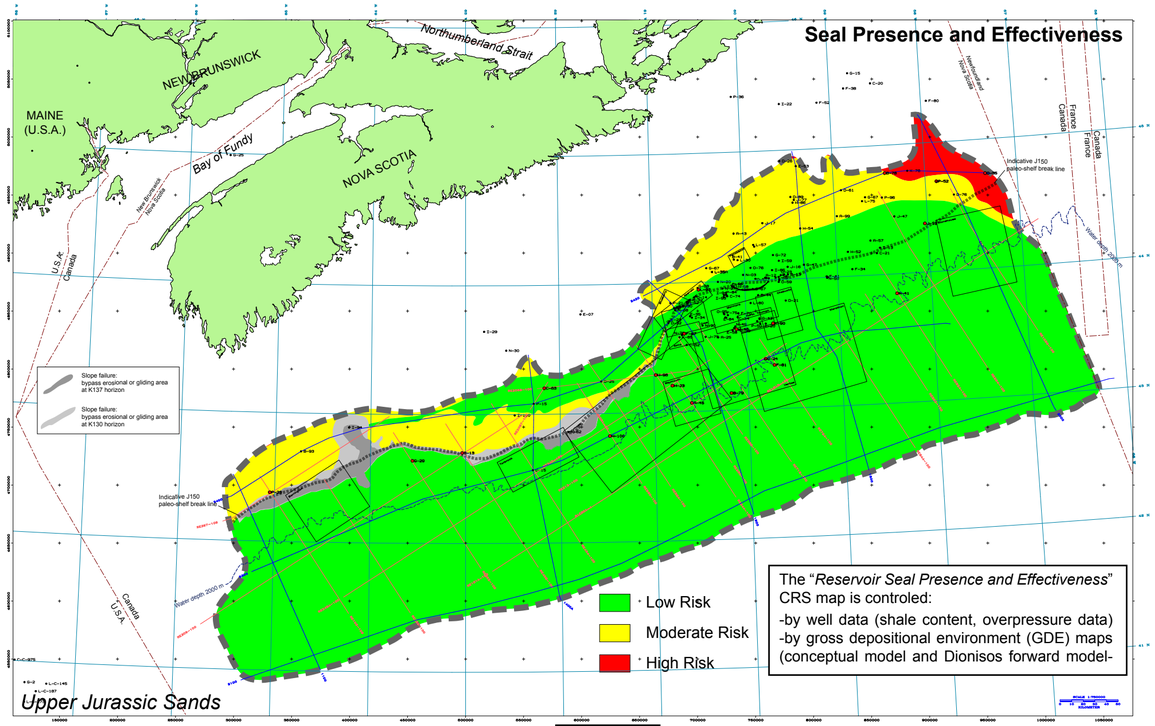
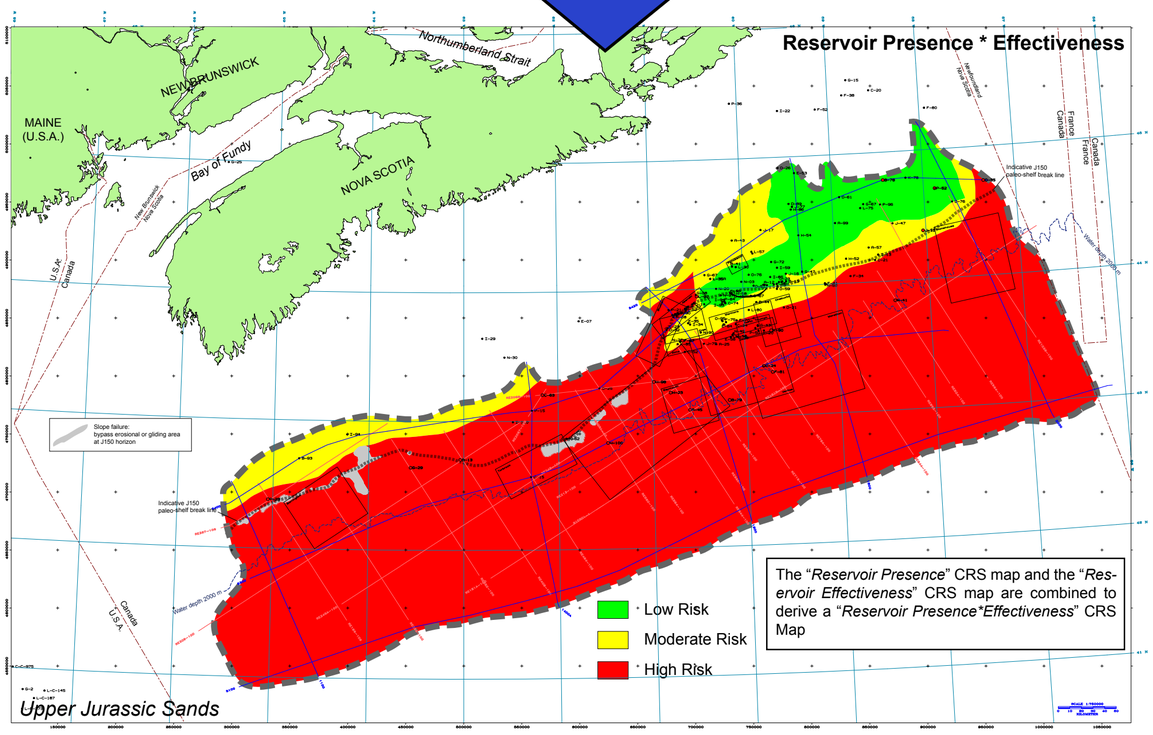
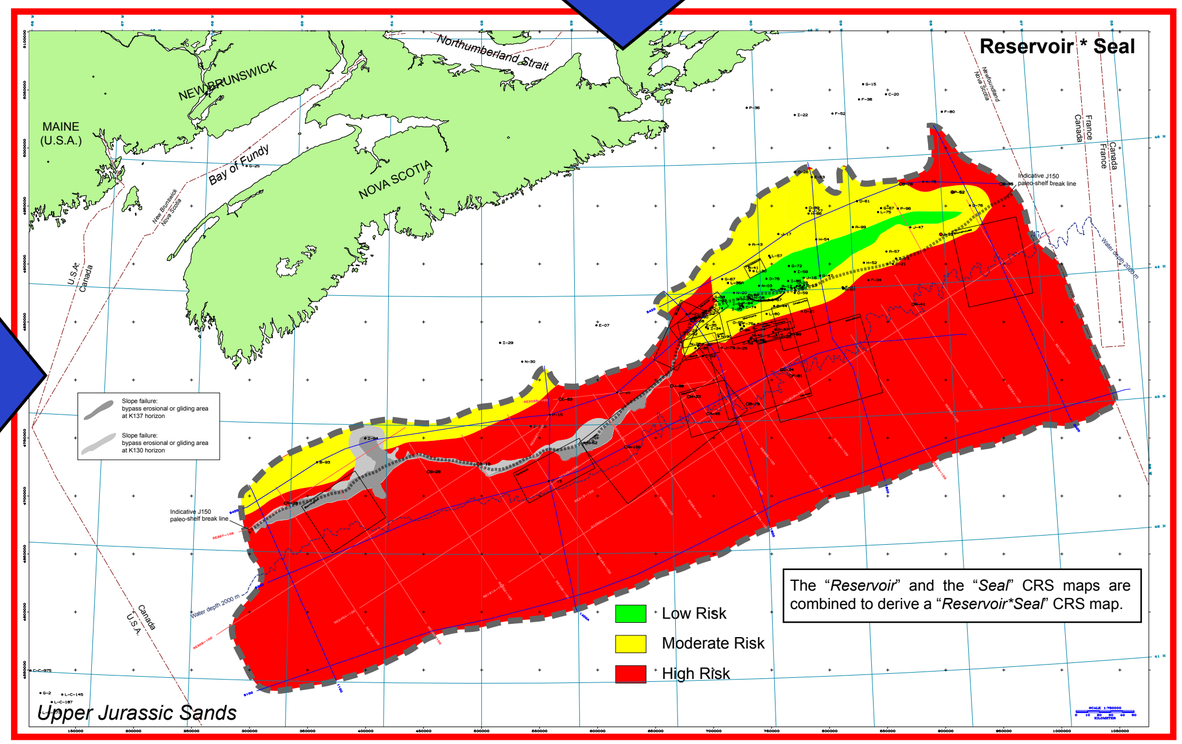


The "*Reservoir Seal Presence and Effectiveness*" CRS map is controled:
-by well data (shale content, overpressure data)
-by gross depositional environment (GDE) maps (conceptual model and Dionisos forward model-



The "*Reservoir Presence*" CRS map and the "*Reservoir Effectiveness*" CRS map are combined to derive a "*Reservoir Presence*Effectiveness*" CRS Map

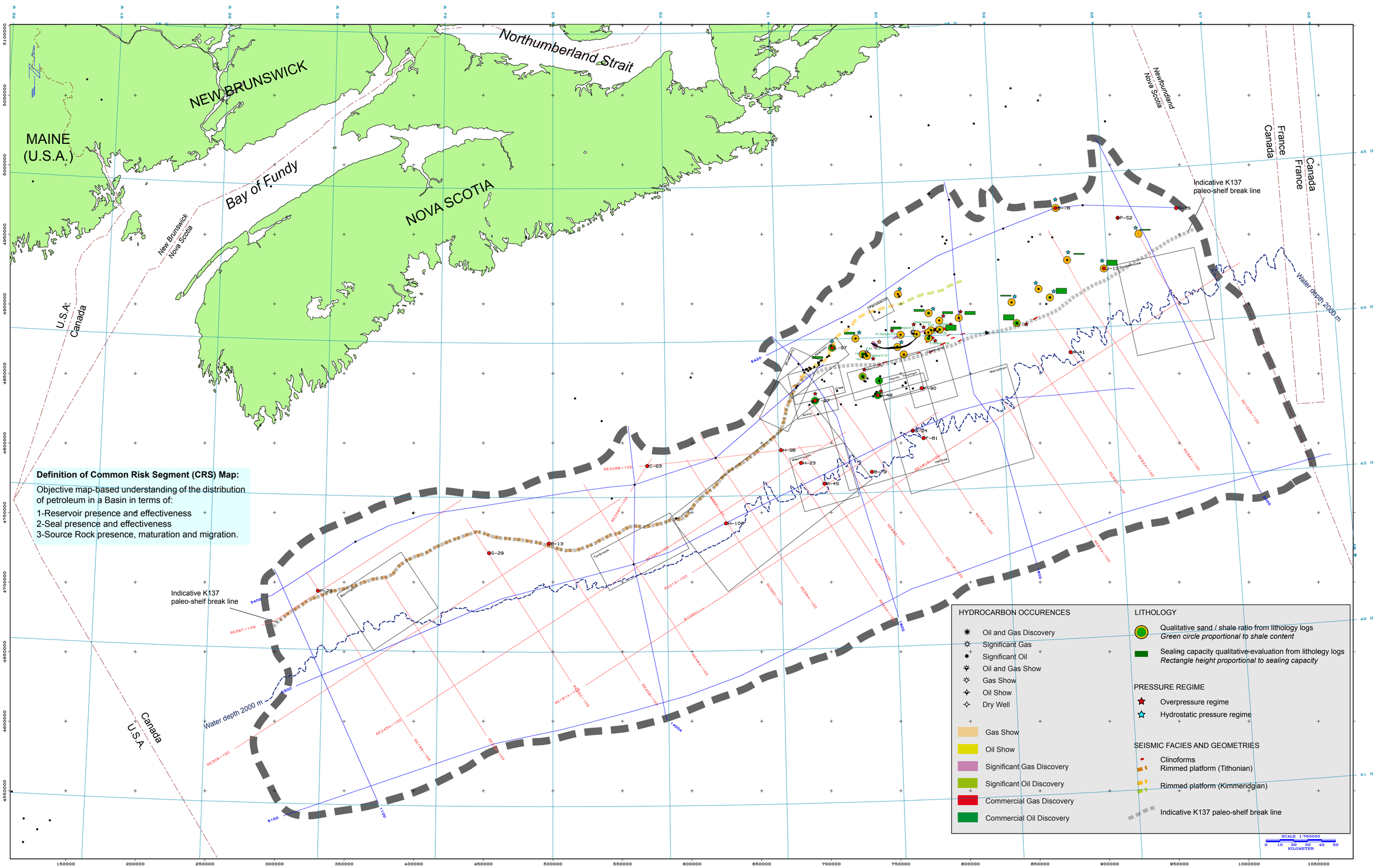


The "*Reservoir*" and the "*Seal*" CRS maps are combined to derive a "*Reservoir*Seal*" CRS map.

PL. 8-2-3 **Upper Jurassic Sands - CRS Mapping - Reservoir and Seal**

PETROLEUM EVALUATION - CRS MAPPING

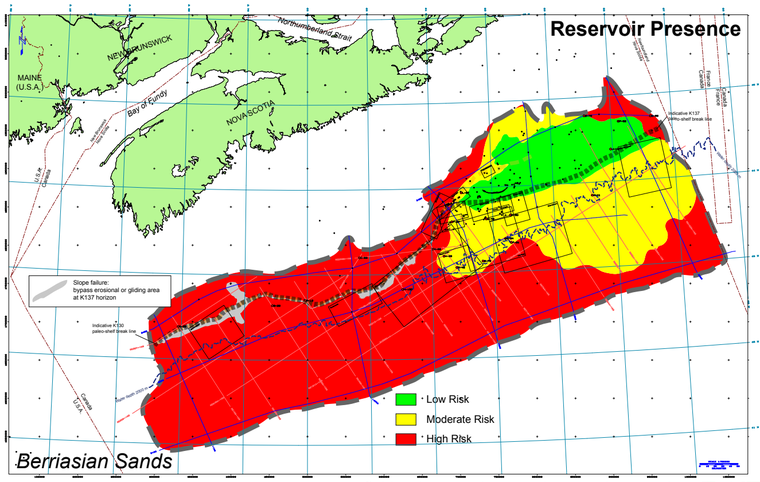
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



PL. 8-2-4 **Berriasian Sands - CRS Mapping - Well and Seismic Data**

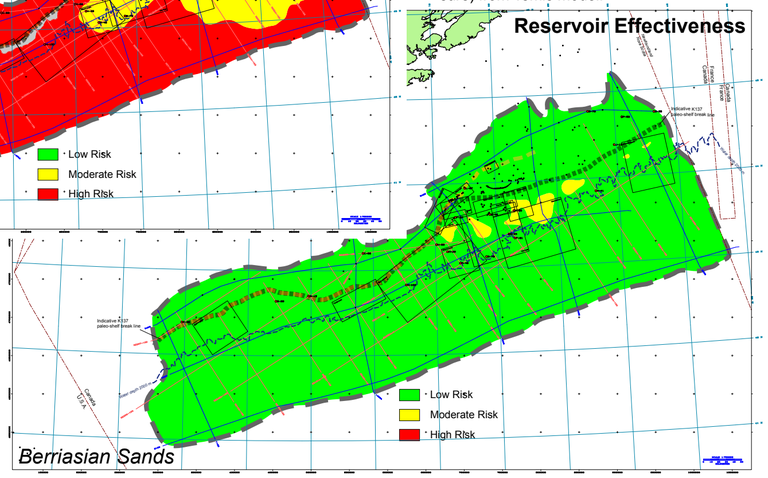
PETROLEUM EVALUATION - CRS MAPPING

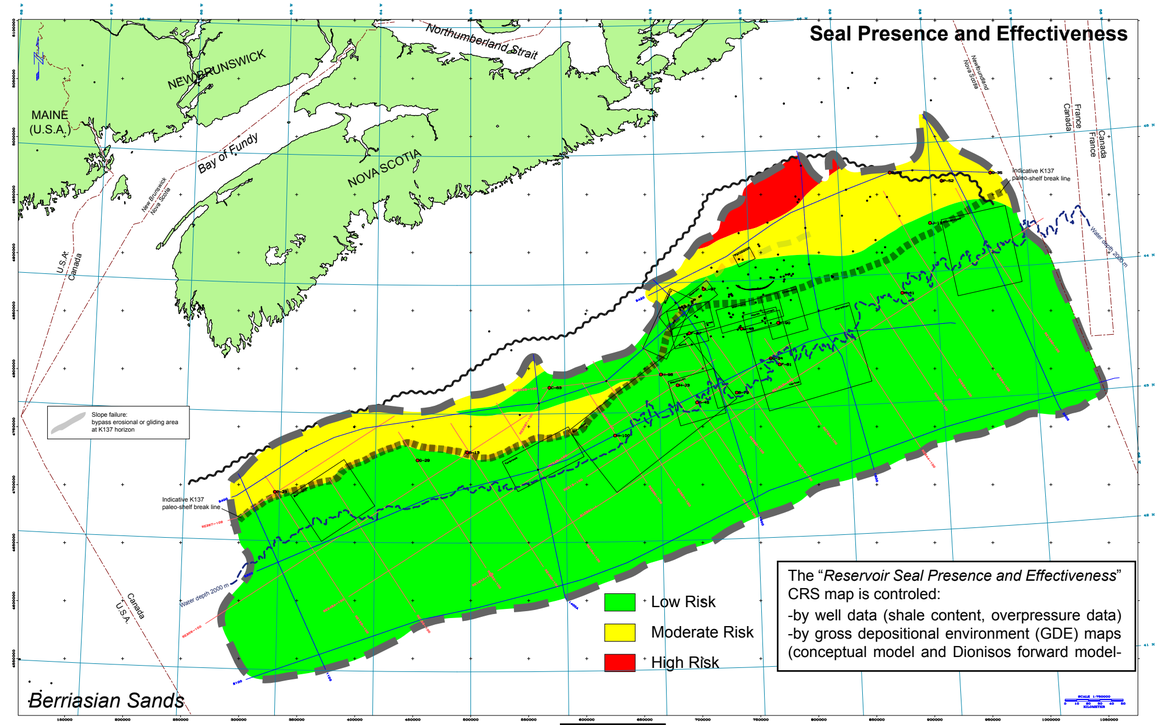
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



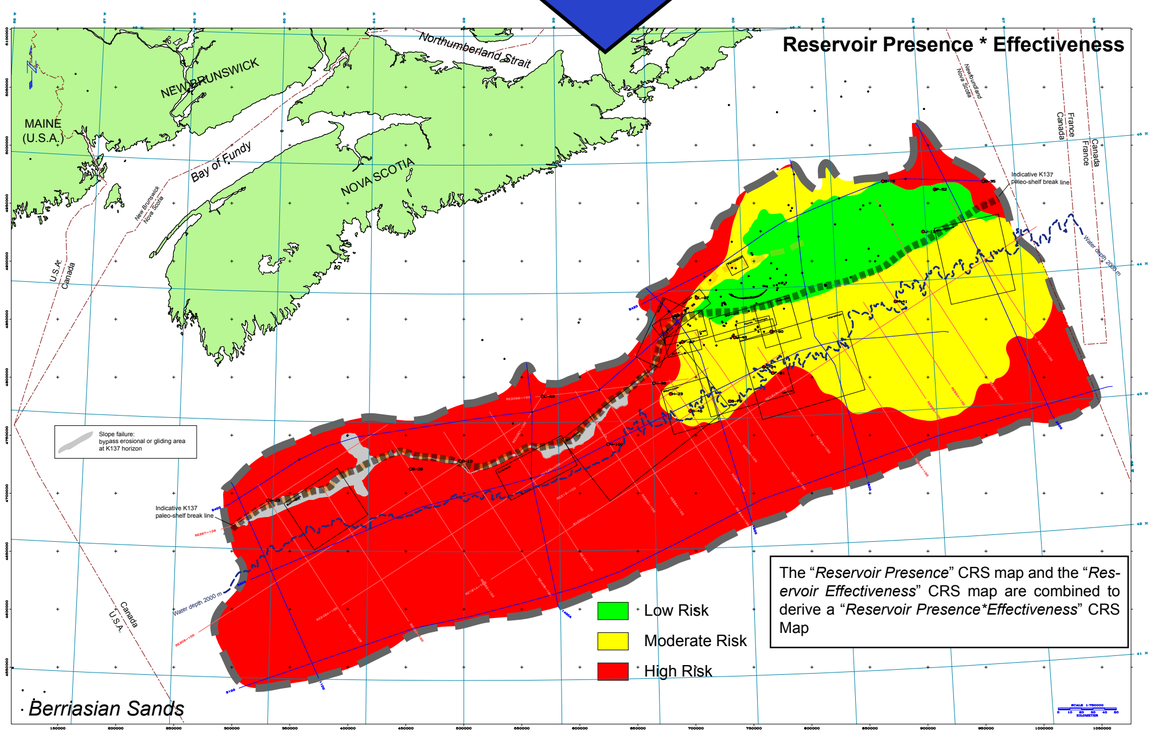
The "*Reservoir Presence*" CRS map is controled by:
-well data (qualitative sand / shale ratio),
-seismic data (seismic facies and geometries),
-gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).

The "*Reservoir Effectiveness*" CRS map is controled by well data (porosity values) and by porosity prediction (compaction and overpressure) from Temis model.

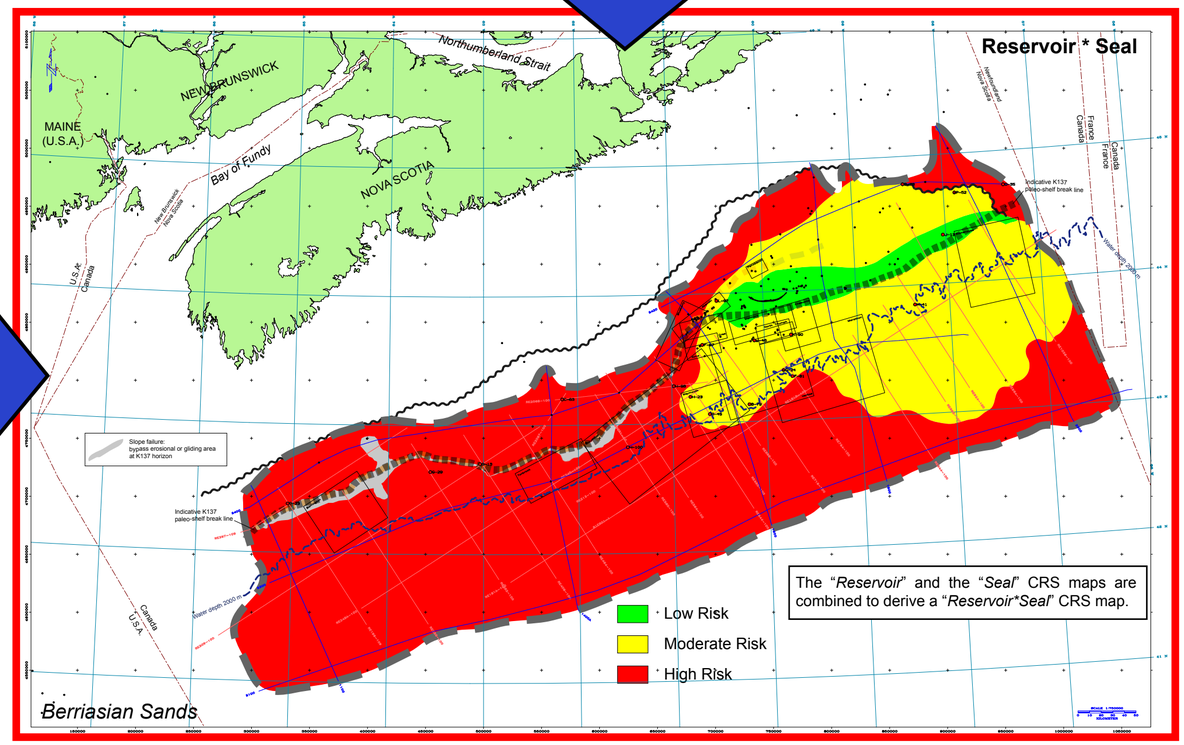




The "*Reservoir Seal Presence and Effectiveness*" CRS map is controled:
-by well data (shale content, overpressure data)
-by gross depositional environment (GDE) maps (conceptual model and Dionisos forward model-



The "*Reservoir Presence*" CRS map and the "*Reservoir Effectiveness*" CRS map are combined to derive a "*Reservoir Presence*Effectiveness*" CRS Map

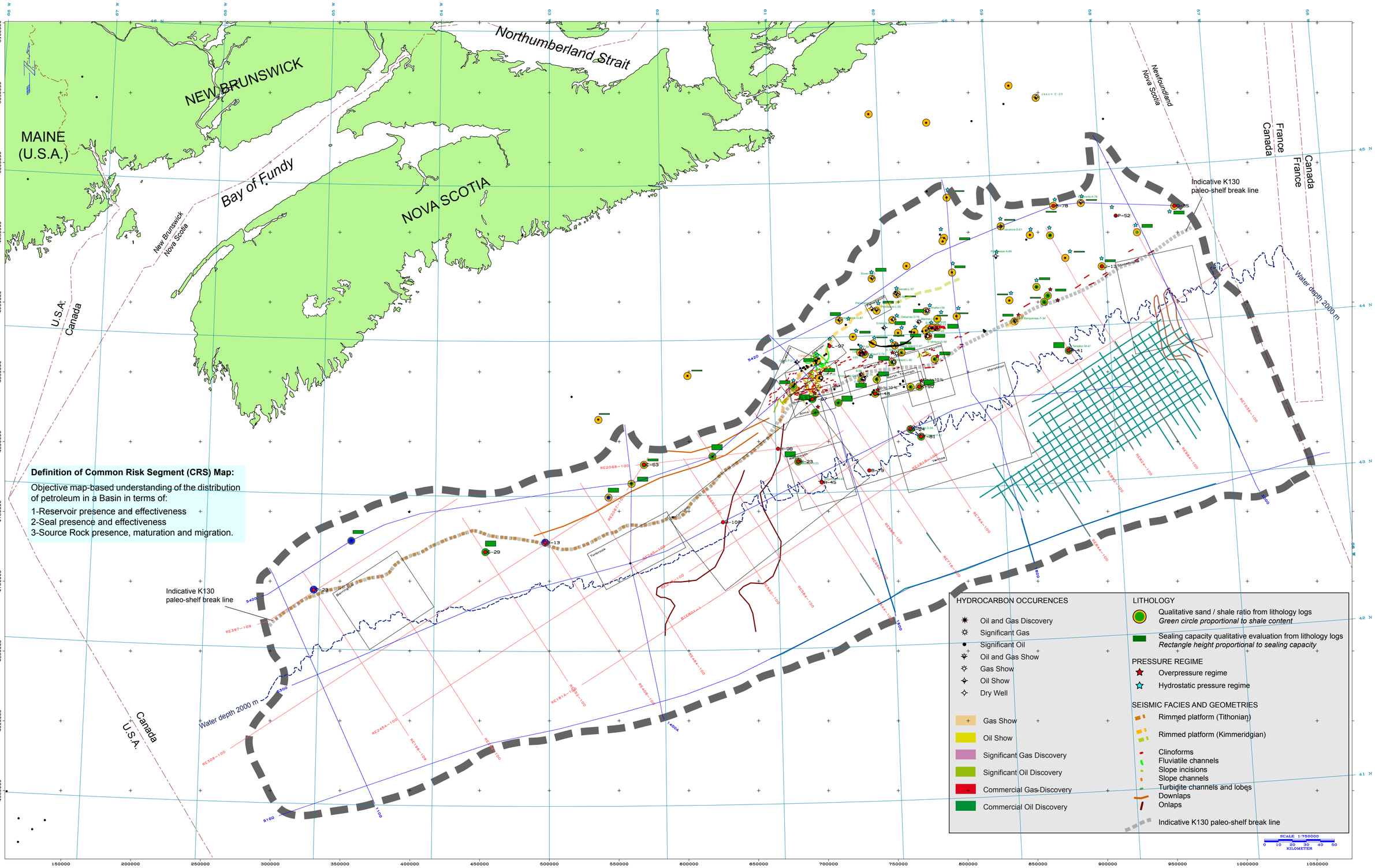


The "*Reservoir*" and the "*Seal*" CRS maps are combined to derive a "*Reservoir*Seal*" CRS map.

Berriasian Sands - CRS Mapping - Reservoir and Seal **PL. 8-2-5**

PETROLEUM EVALUATION - CRS MAPPING

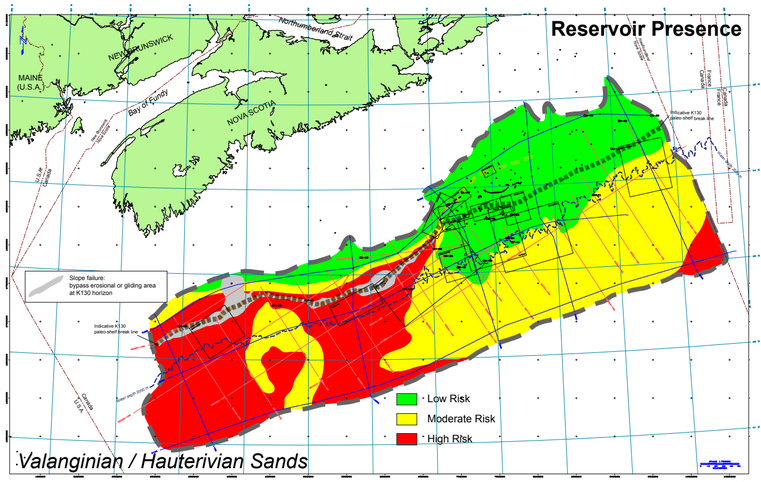
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



PL. 8-2-6 — Valanginian / Hauterivian Sands - CRS Mapping - Well and Seismic Data

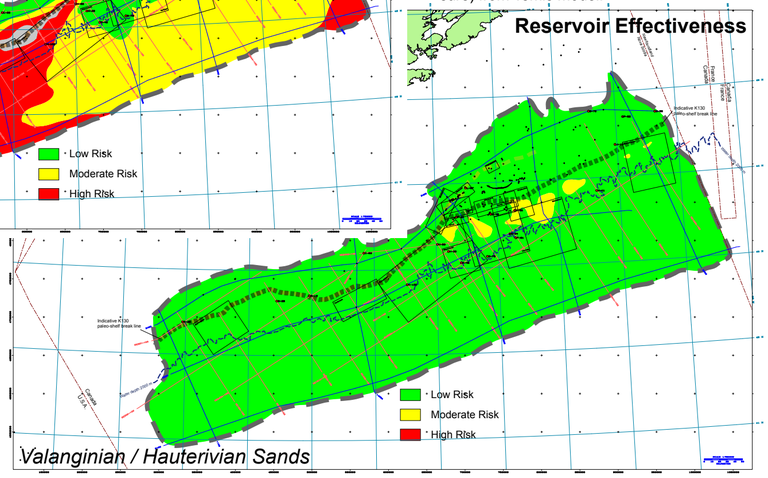
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



The "*Reservoir Presence*" CRS map is controled by:
-well data (qualitative sand / shale ratio),
-seismic data (seismic facies and geometries),
-gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).

The "*Reservoir Effectiveness*" CRS map is controled by well data (porosity values) and by porosity prediction (compaction and overpressure) from Temis model.



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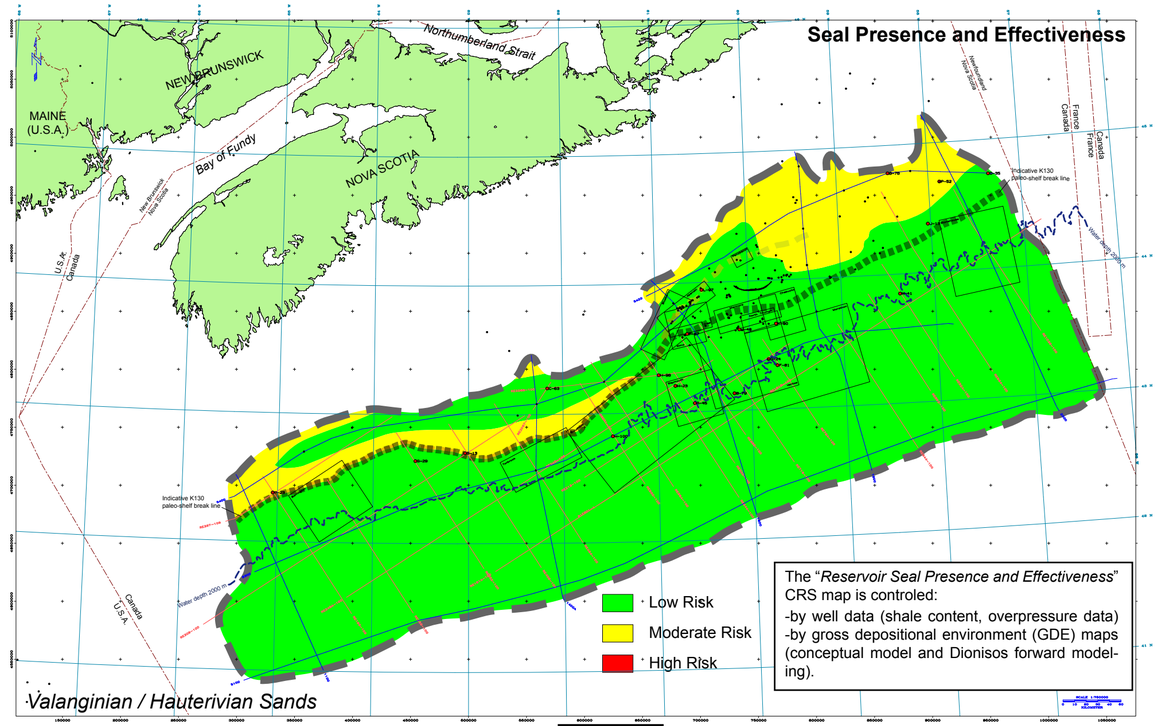
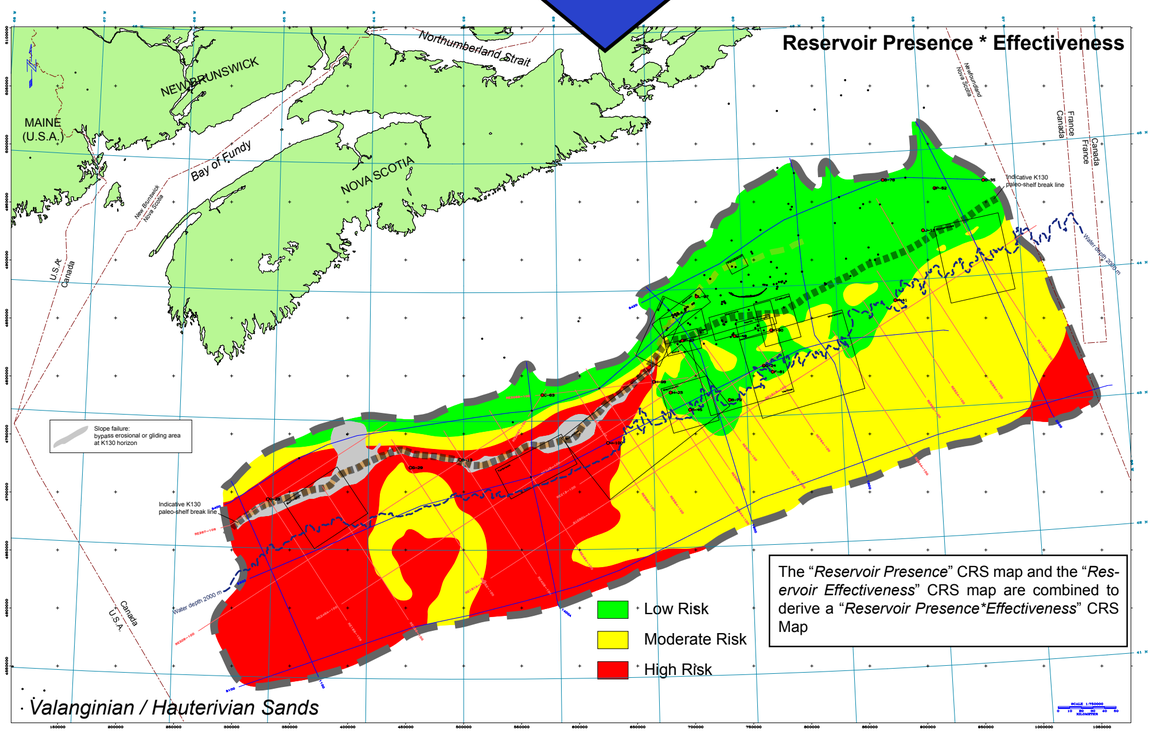
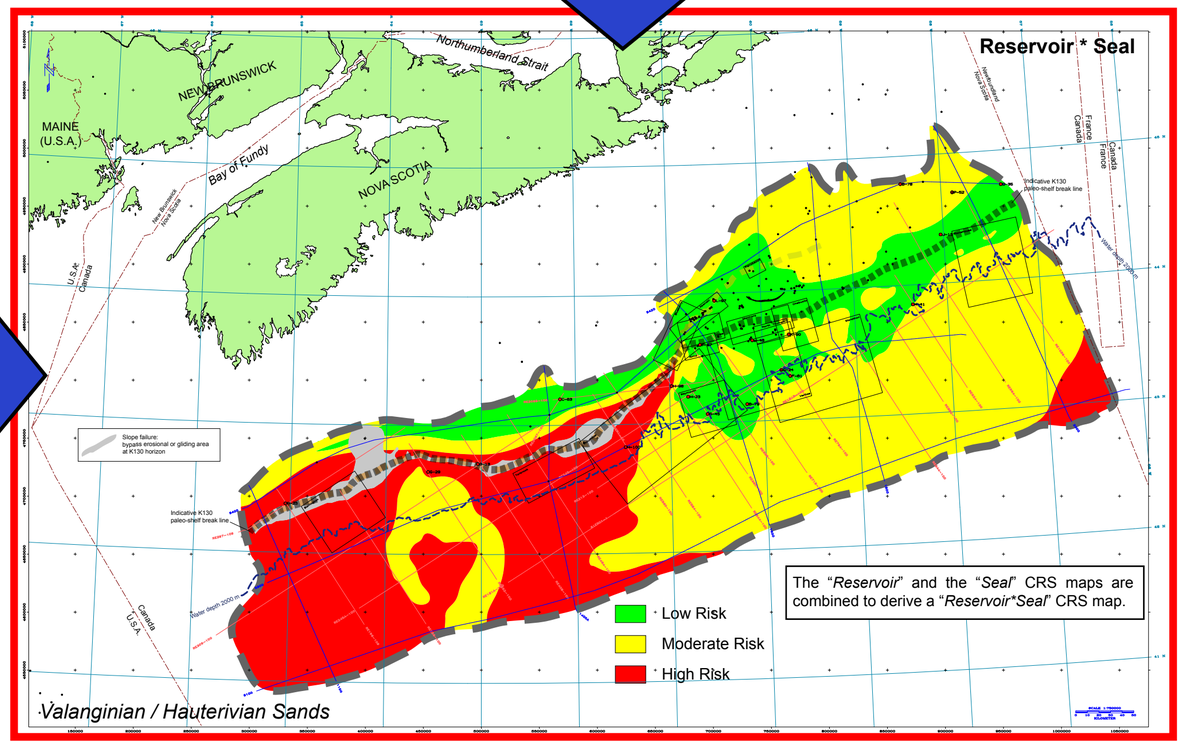


The "*Reservoir Seal Presence and Effectiveness*" CRS map is controled:
-by well data (shale content, overpressure data)
-by gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).



The "*Reservoir Presence*" CRS map and the "*Reservoir Effectiveness*" CRS map are combined to derive a "*Reservoir Presence*Effectiveness*" CRS Map

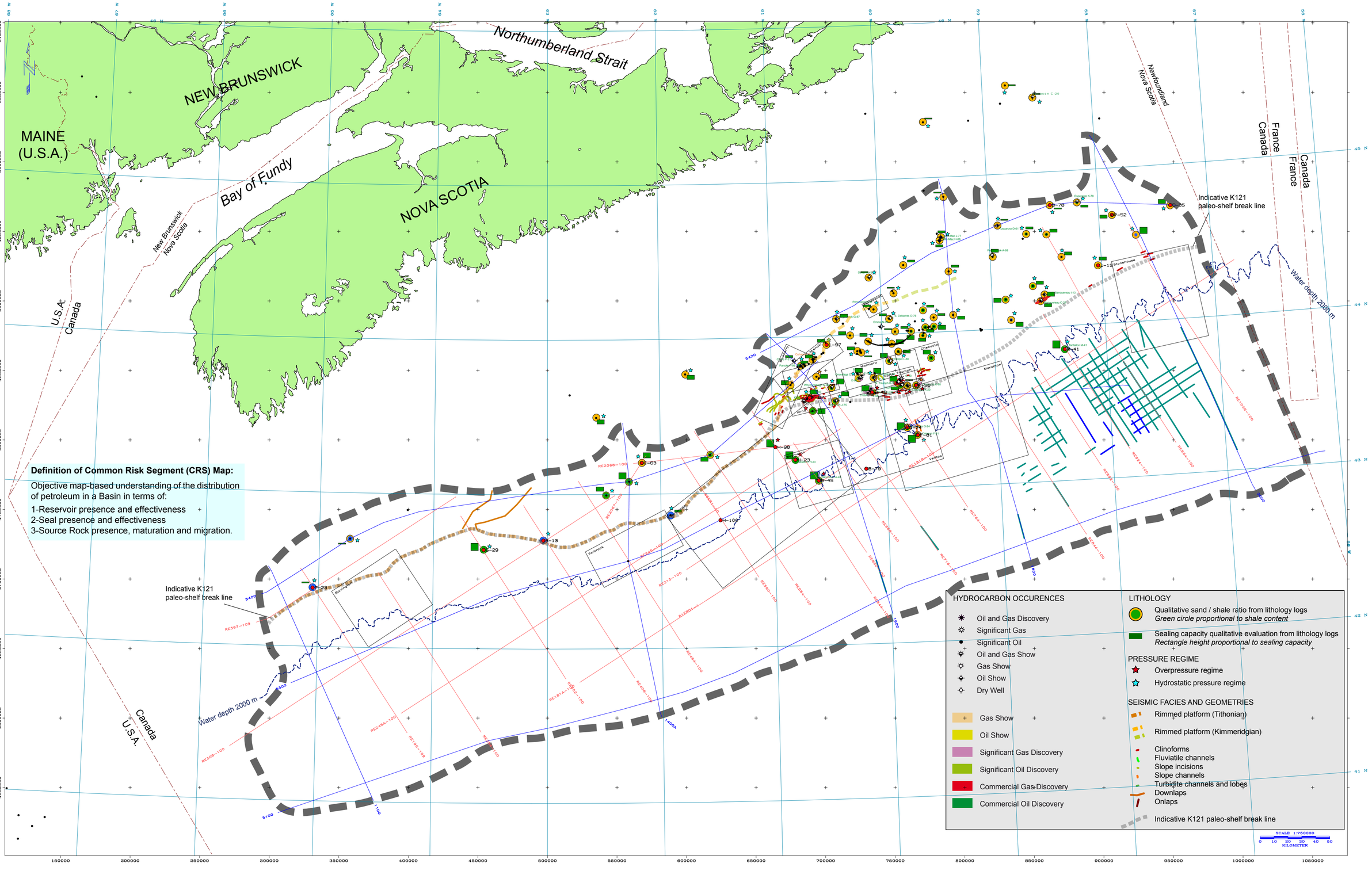


The "*Reservoir*" and the "*Seal*" CRS maps are combined to derive a "*Reservoir*Seal*" CRS map.

Valanginian / Hauterivian Sands - CRS Mapping - Reservoir and Seal **PL. 8-2-7**

PETROLEUM EVALUATION - CRS MAPPING

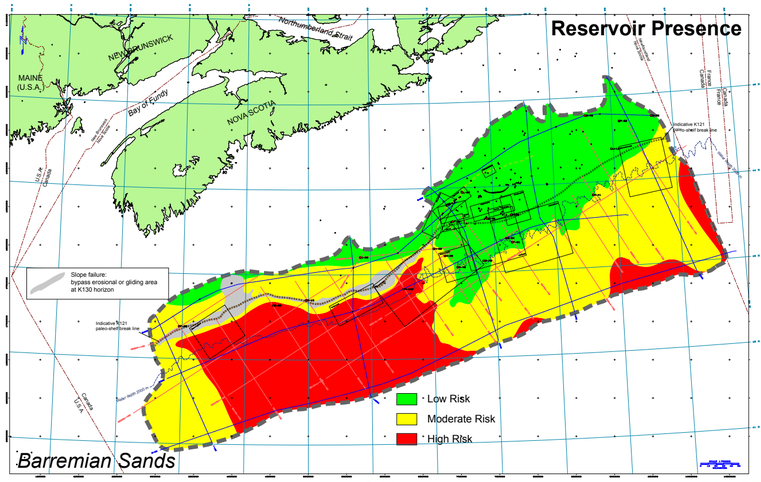
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



PL. 8-2-8 **Barremian Sands - CRS Mapping - Well and Seismic Data**

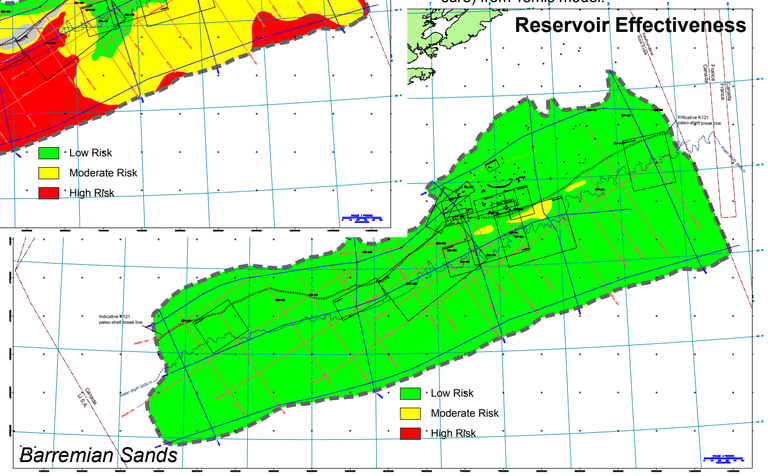
PETROLEUM EVALUATION - CRS MAPPING

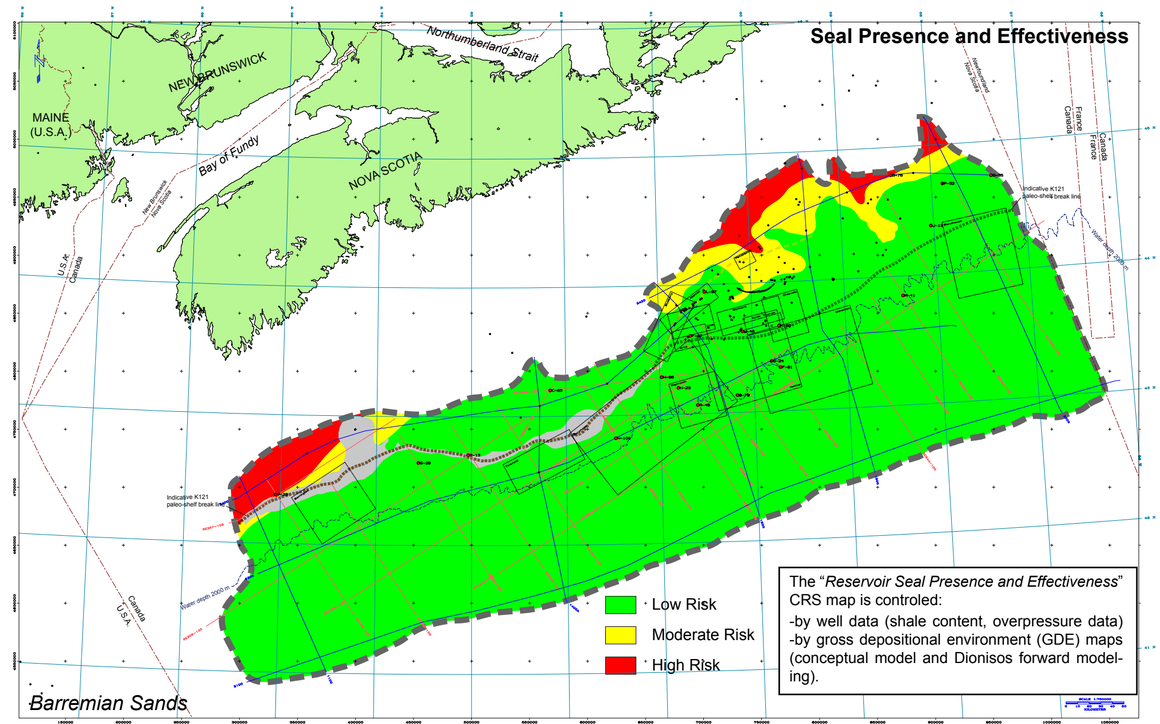
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



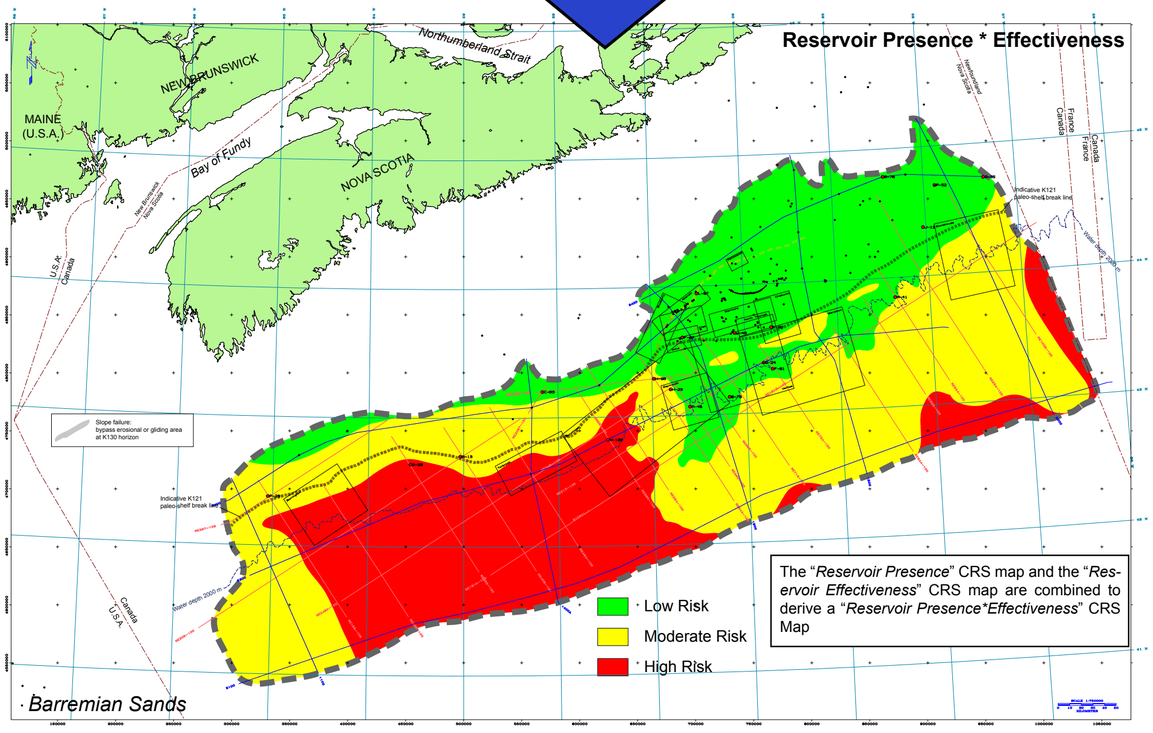
The "*Reservoir Presence*" CRS map is controled by:
-well data (qualitative sand / shale ratio),
-seismic data (seismic facies and geometries),
-gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).

The "*Reservoir Effectiveness*" CRS map is controled by well data (porosity values) and by porosity prediction (compaction and overpressure) from Temis model.

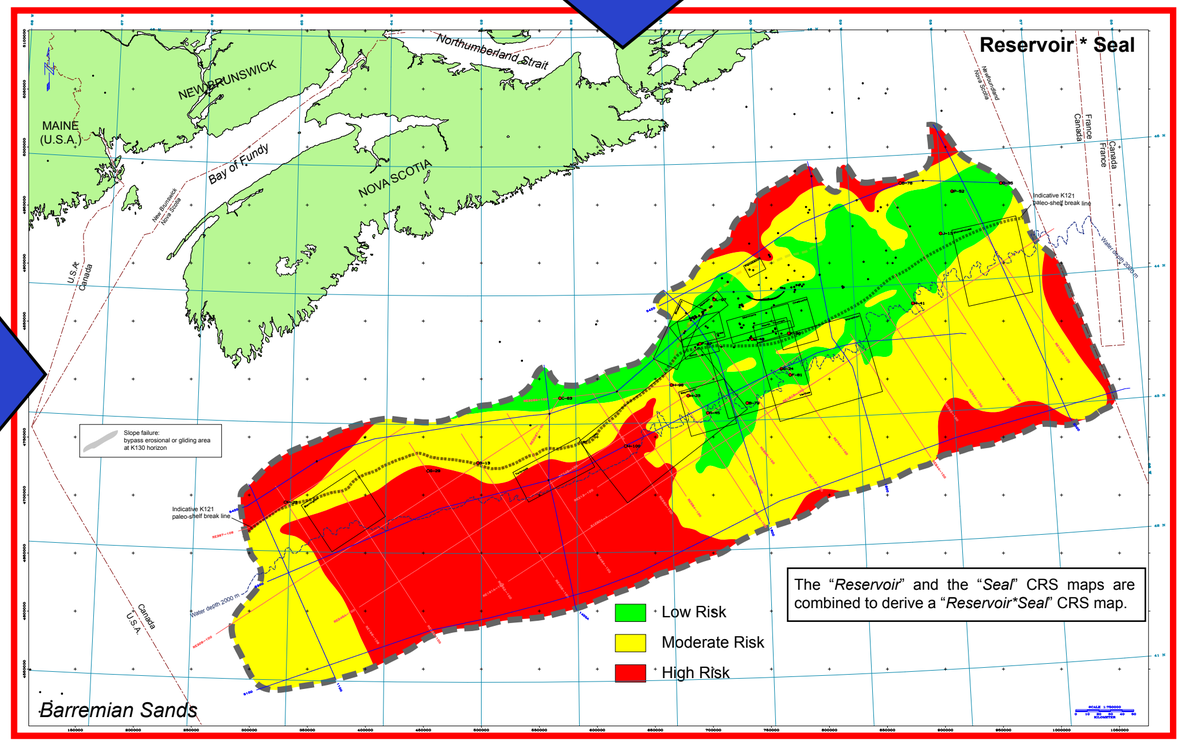




The "*Reservoir Seal Presence and Effectiveness*" CRS map is controled:
-by well data (shale content, overpressure data)
-by gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).



The "*Reservoir Presence*" CRS map and the "*Reservoir Effectiveness*" CRS map are combined to derive a "*Reservoir Presence*Effectiveness*" CRS Map*

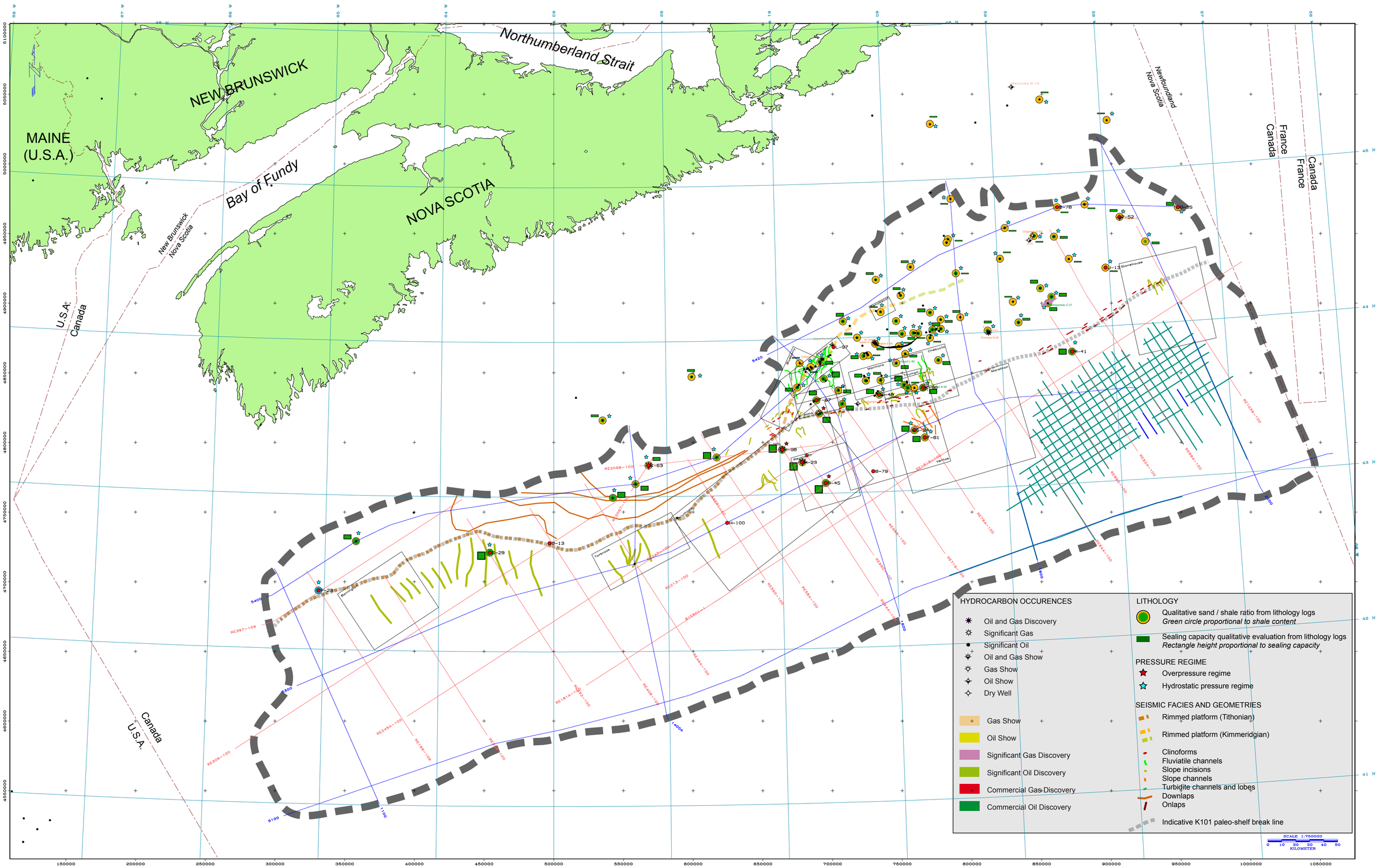


The "*Reservoir*" and the "*Seal*" CRS maps are combined to derive a "*Reservoir*Seal*" CRS map.

Barremian Sands - CRS Mapping - Reservoir and Seal **PL. 8-2-9**

PETROLEUM EVALUATION - CRS MAPPING

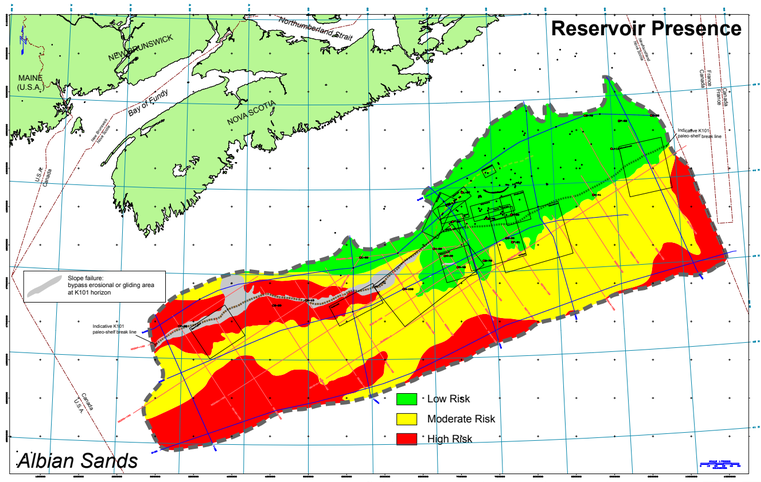
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



PL. 8-2-10 **Albian Sands - CRS Mapping - Well and Seismic Data**

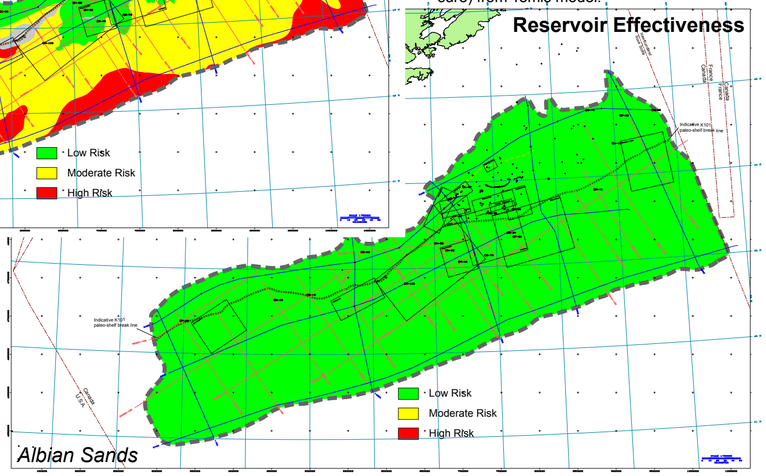
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

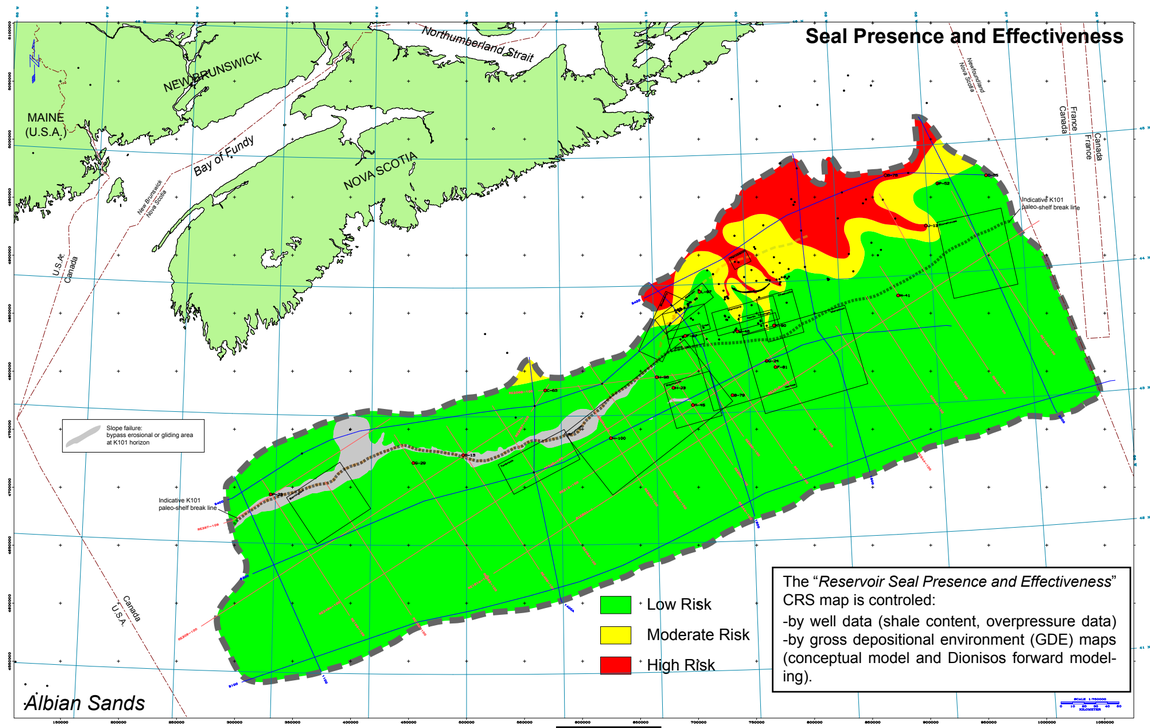


The "*Reservoir Presence*" CRS map is controled by:
-well data (qualitative sand / shale ratio),
-seismic data (seismic facies and geometries),
-gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).

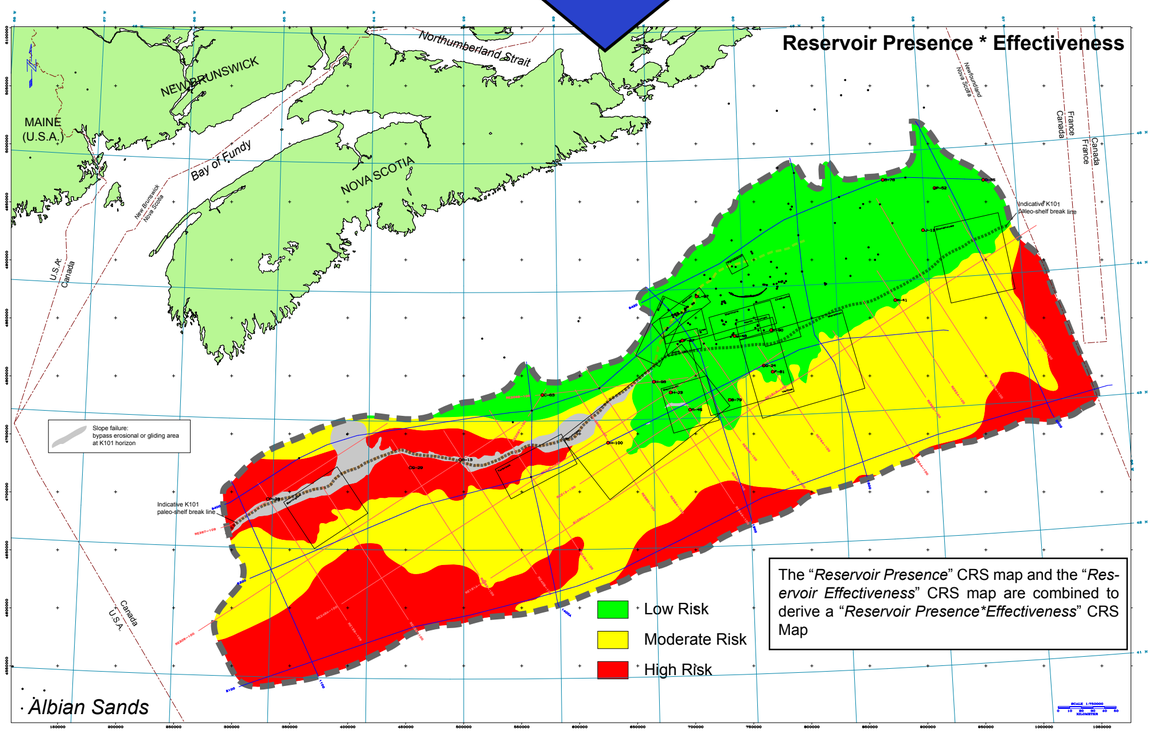
The "*Reservoir Effectiveness*" CRS map is controled by well data (porosity values) and by porosity prediction (compaction and overpressure) from Temis model.



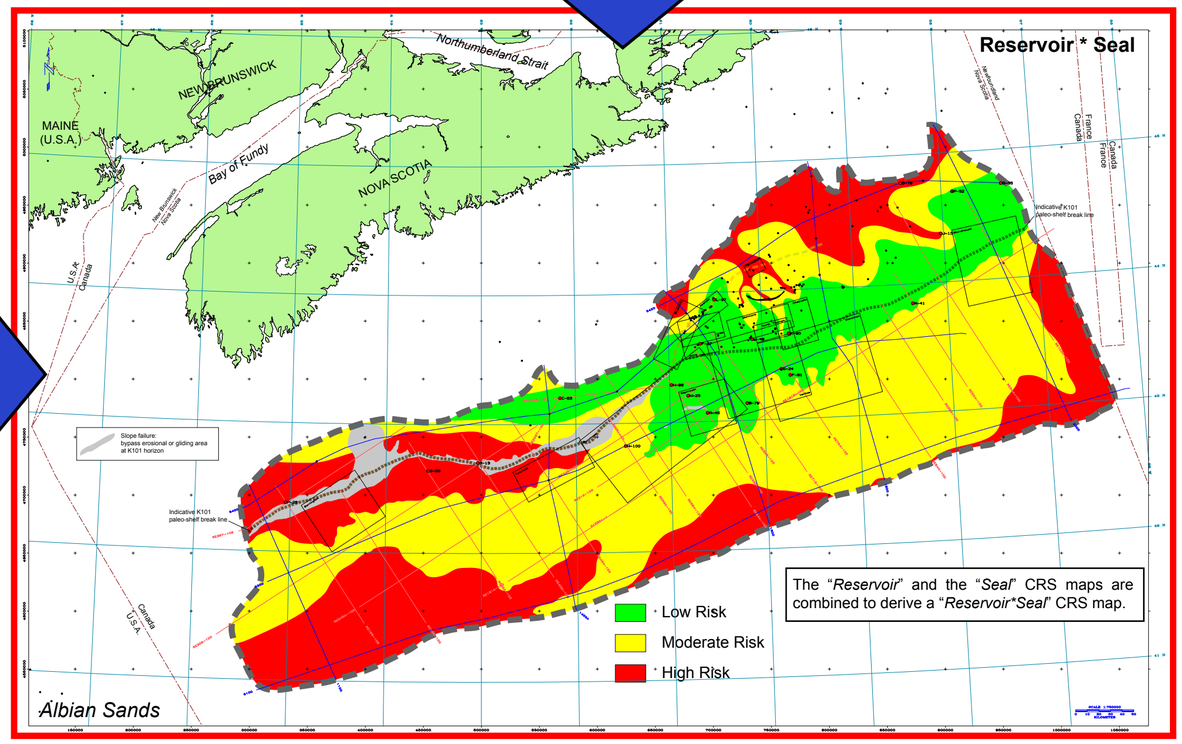
*



The "*Reservoir Seal Presence and Effectiveness*" CRS map is controled:
-by well data (shale content, overpressure data)
-by gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).



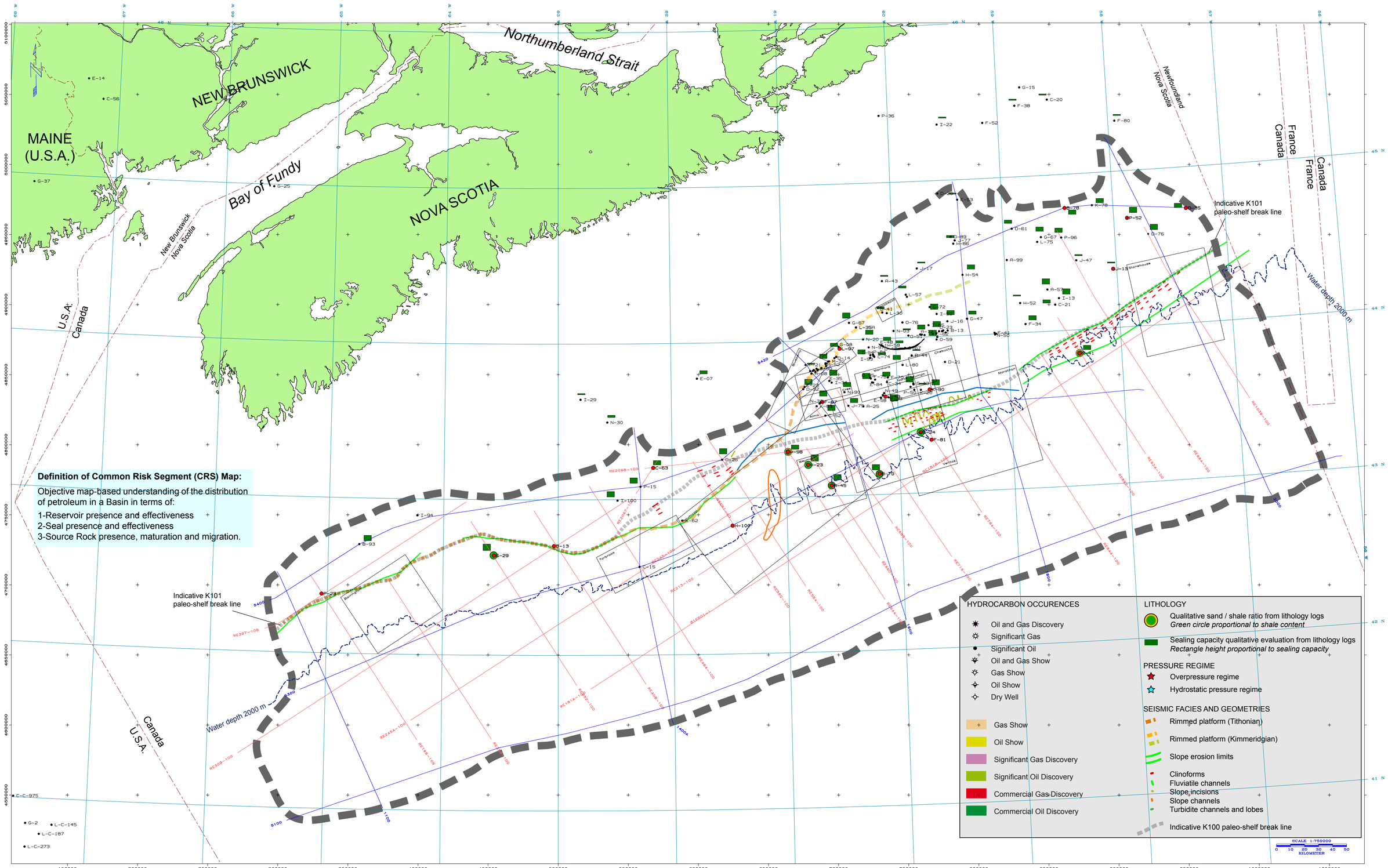
The "*Reservoir Presence*" CRS map and the "*Reservoir Effectiveness*" CRS map are combined to derive a "*Reservoir Presence*Effectiveness*" CRS Map



The "*Reservoir*" and the "*Seal*" CRS maps are combined to derive a "*Reservoir*Seal*" CRS map.

PETROLEUM EVALUATION - CRS MAPPING

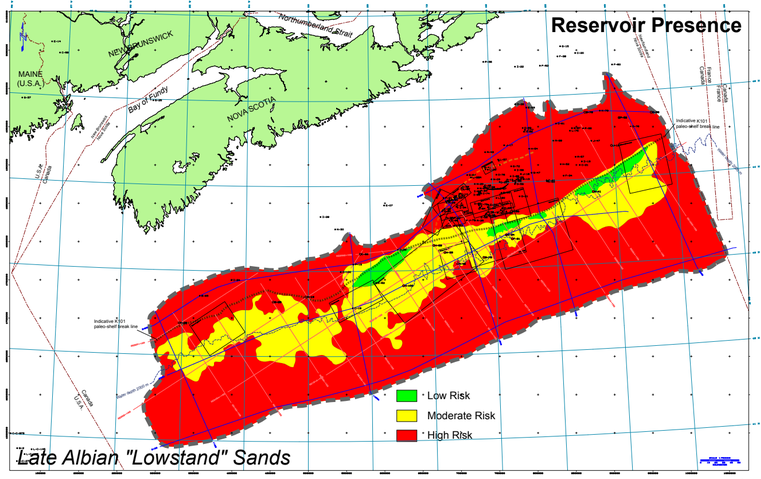
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



PL. 8-2-12 **Late Albian "Lowstand" Sands - CRS Mapping - Well and Seismic Data**

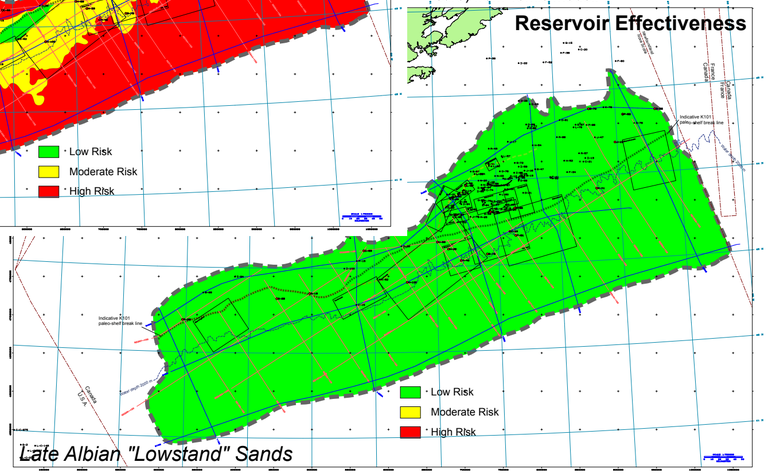
PETROLEUM EVALUATION - CRS MAPPING

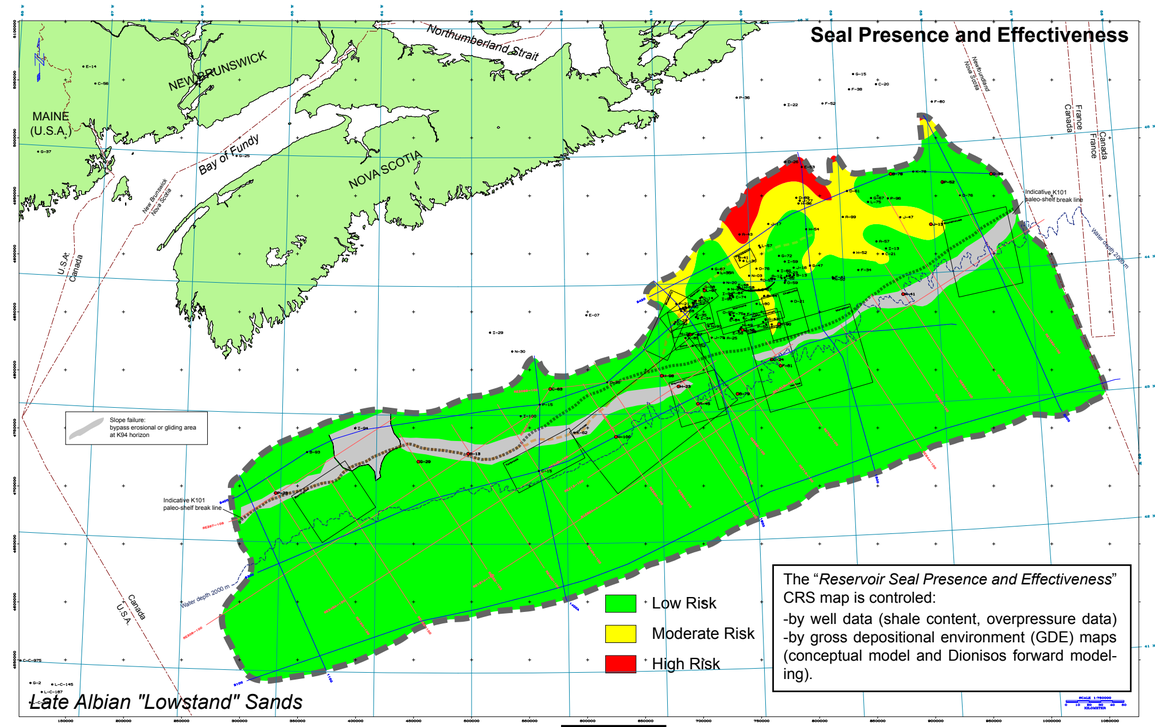
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011



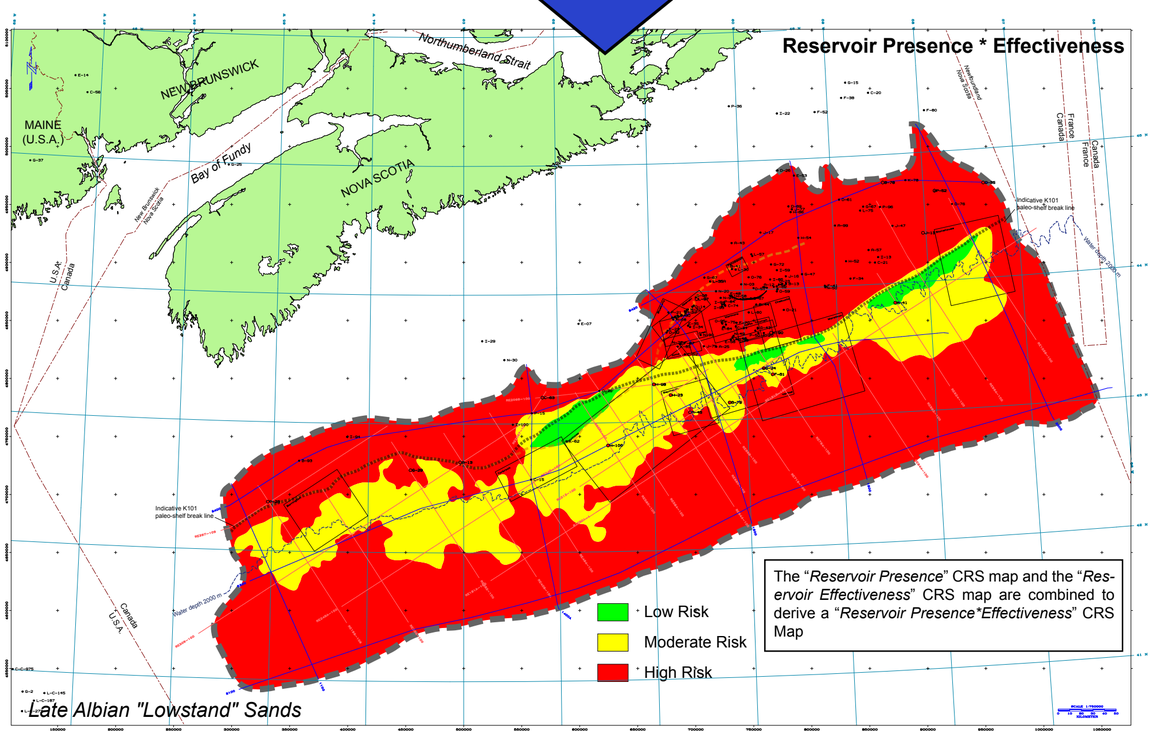
The "*Reservoir Presence*" CRS map is controled by:
-well data (qualitative sand / shale ratio),
-seismic data (seismic facies and geometries),
-gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).

The "*Reservoir Effectiveness*" CRS map is controled by well data (porosity values) and by porosity prediction (compaction and overpressure) from Temis model.

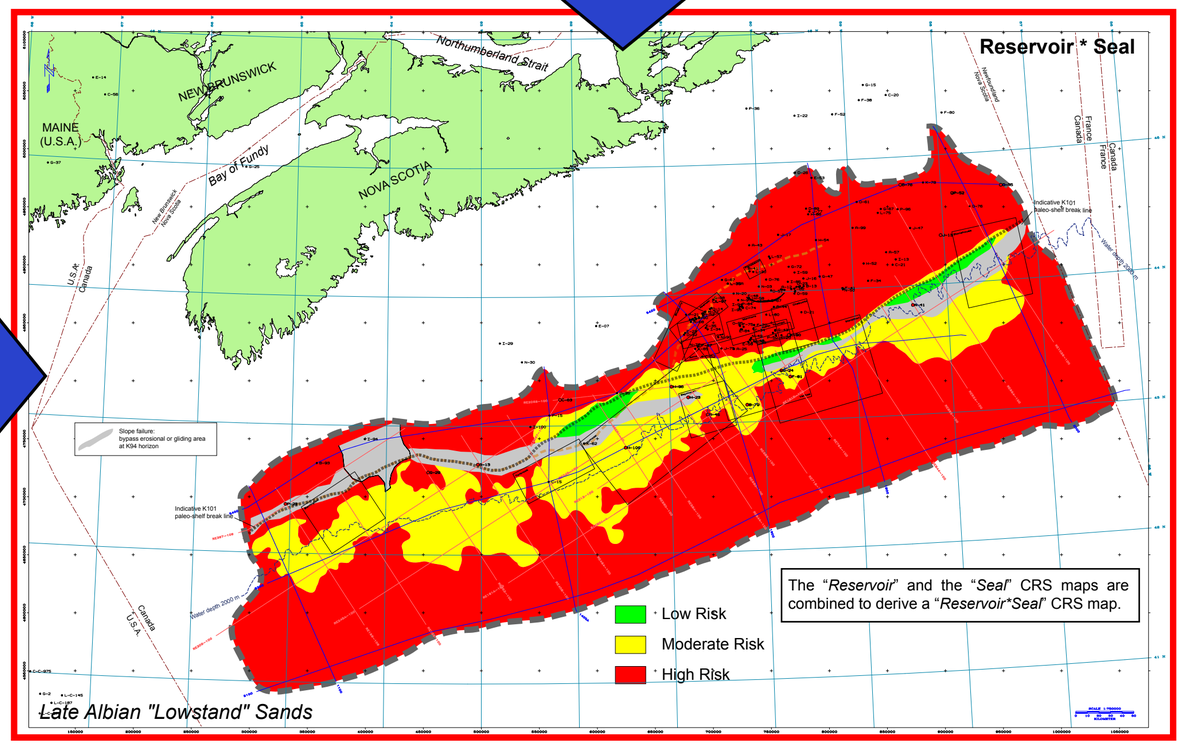




The "*Reservoir Seal Presence and Effectiveness*" CRS map is controled:
-by well data (shale content, overpressure data)
-by gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling).



The "*Reservoir Presence*" CRS map and the "*Reservoir Effectiveness*" CRS map are combined to derive a "*Reservoir Presence*Effectiveness*" CRS Map

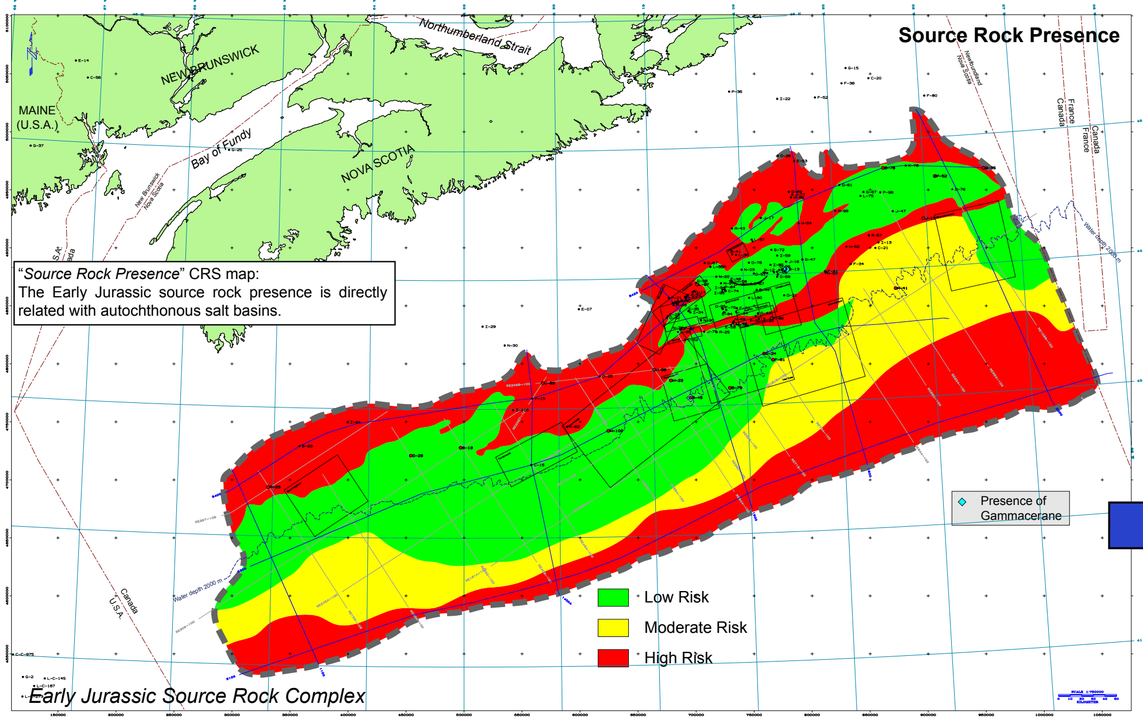


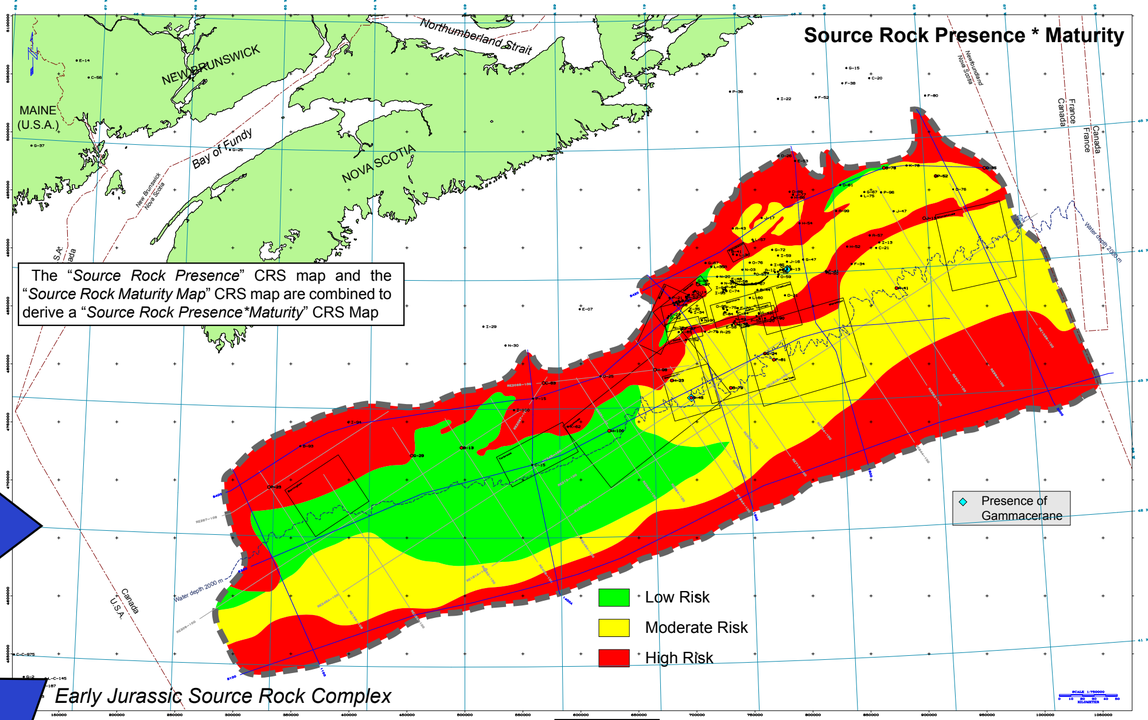
The "*Reservoir*" and the "*Seal*" CRS maps are combined to derive a "*Reservoir*Seal*" CRS map.

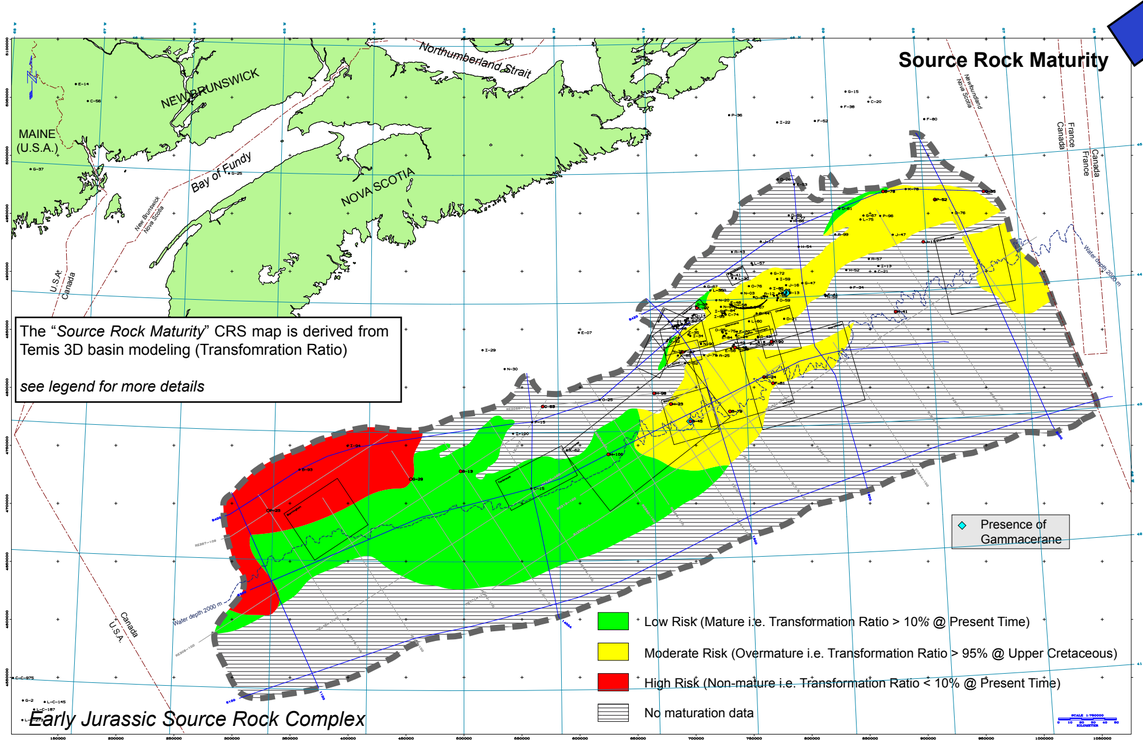
Late Albian "Lowstand" Sands - CRS Mapping - Reservoir and Seal **PL. 8-2-13**

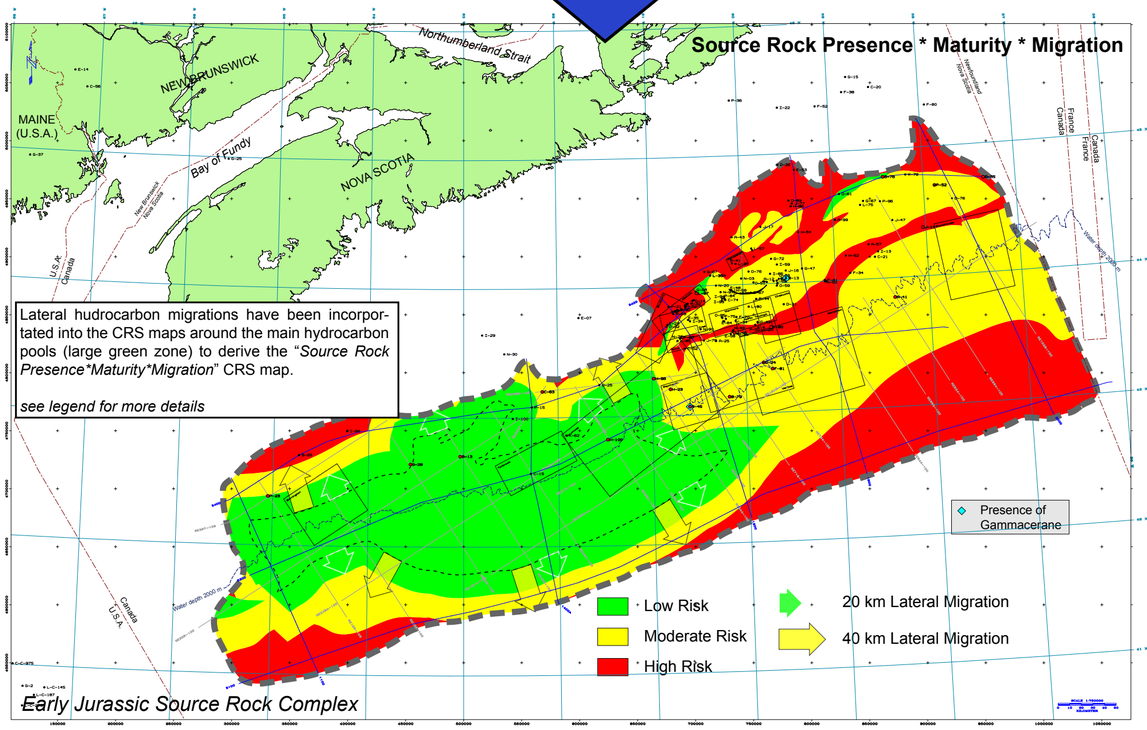
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011





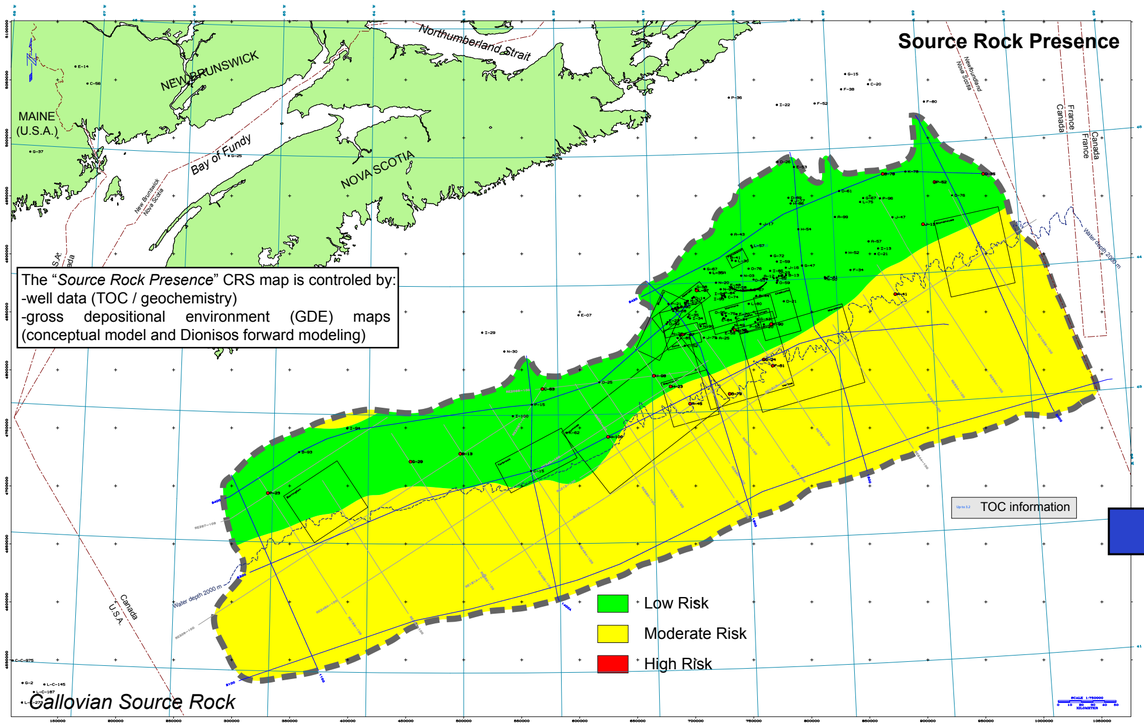


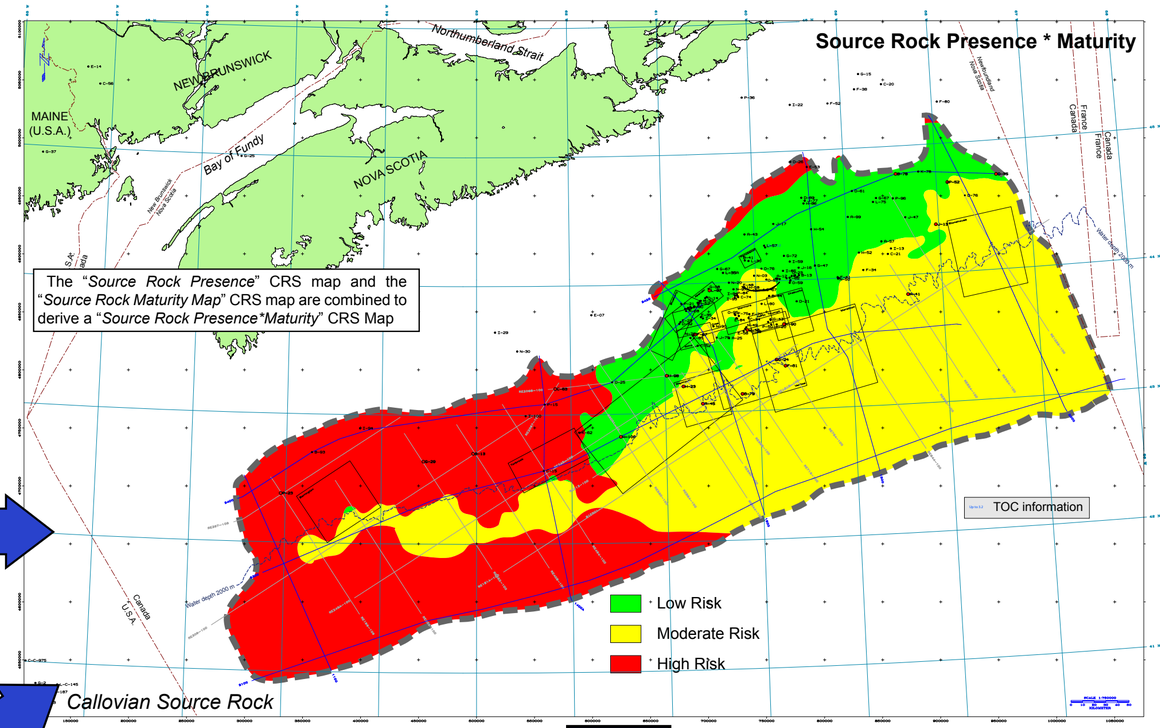


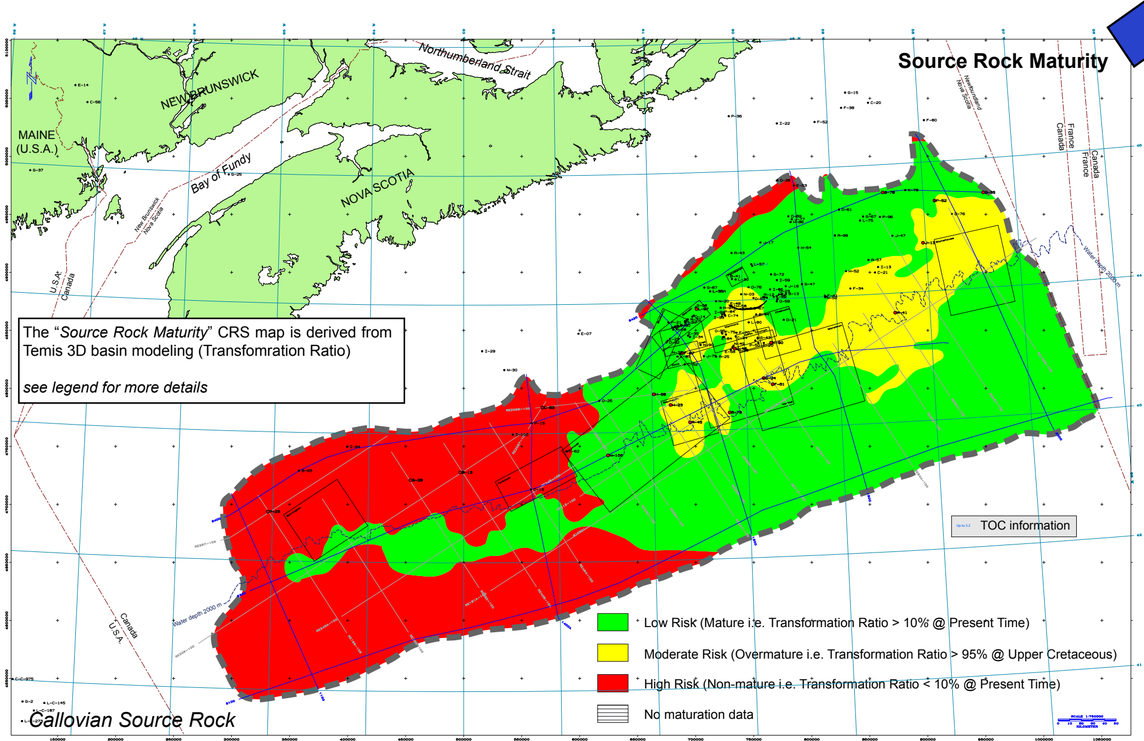
PL. 8-2-14 **Early Jurassic Source Rock Complex - CRS Mapping - Presence, Maturity and Migration**

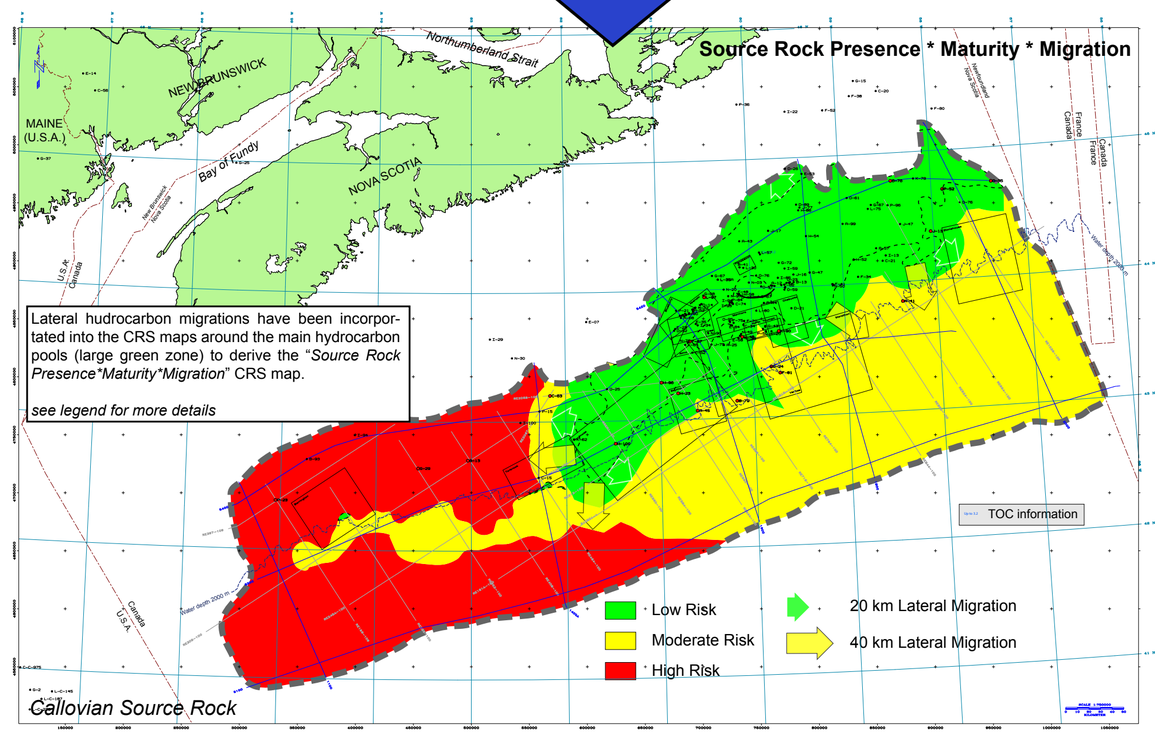
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011







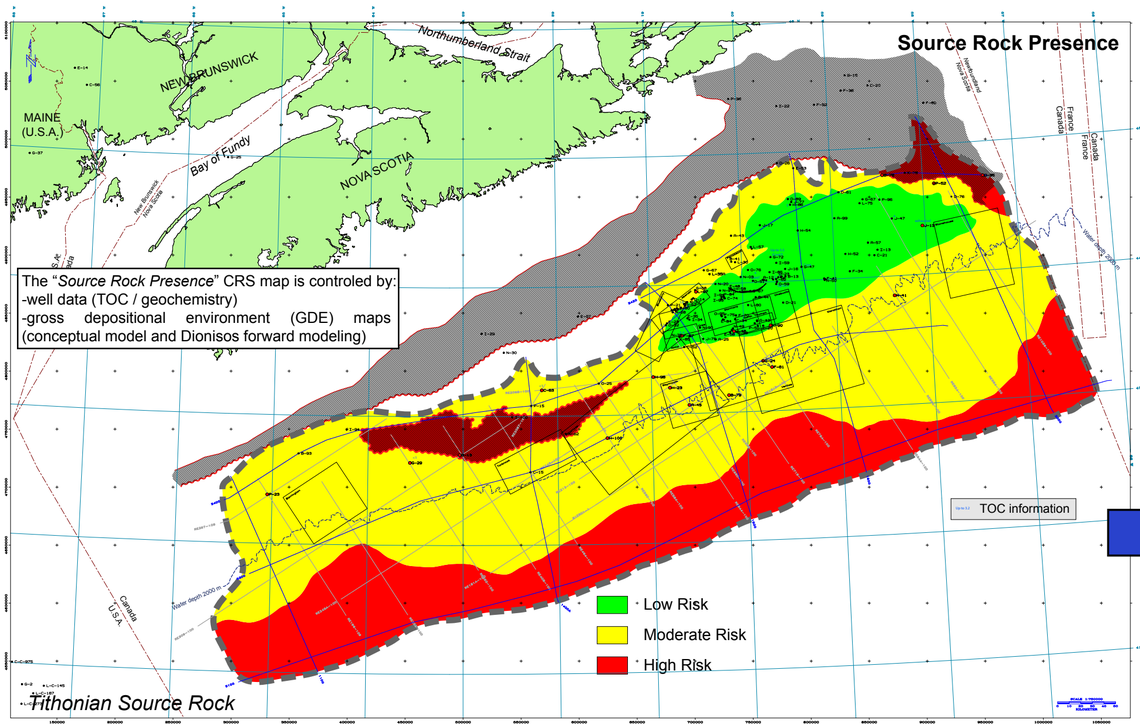


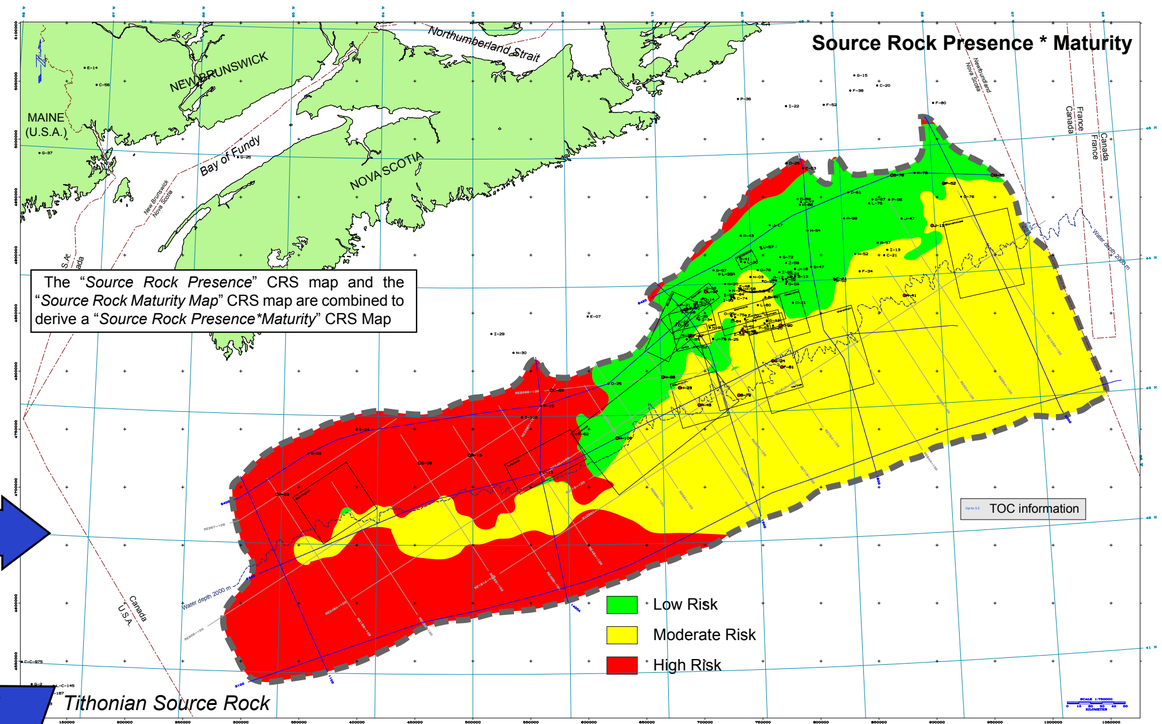
Callovian Source Rock - CRS Mapping - Presence, Maturity and Migration

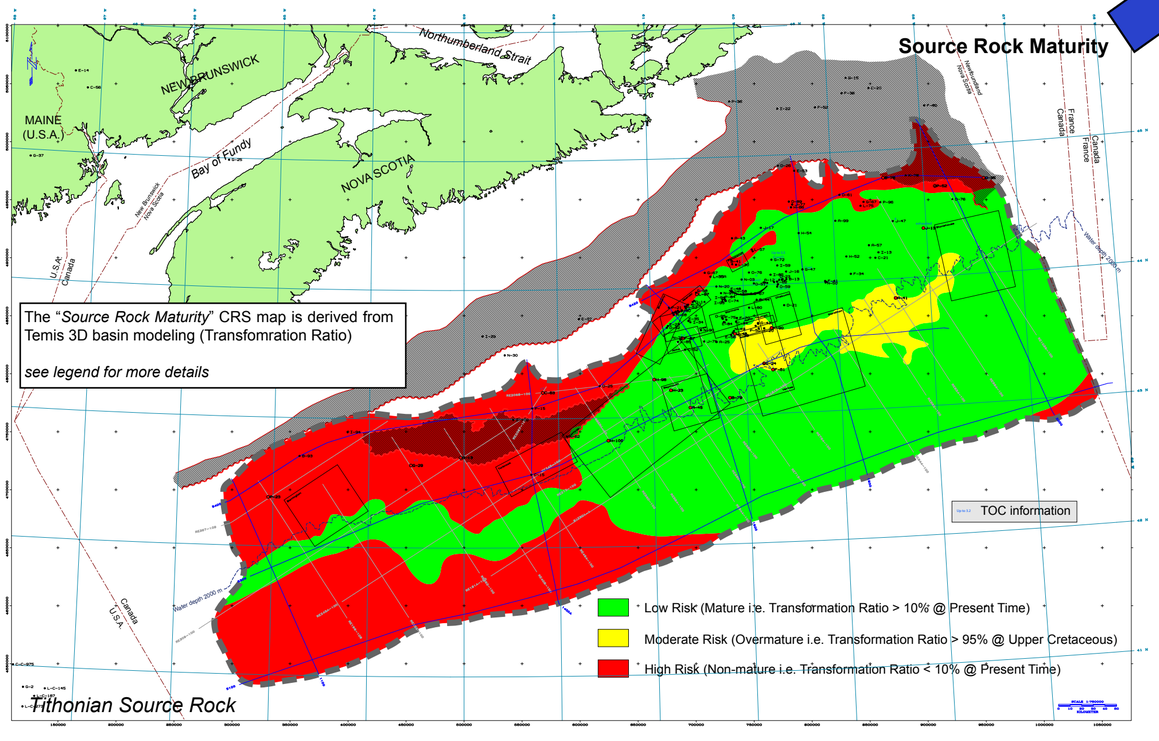
PL. 8-2-15

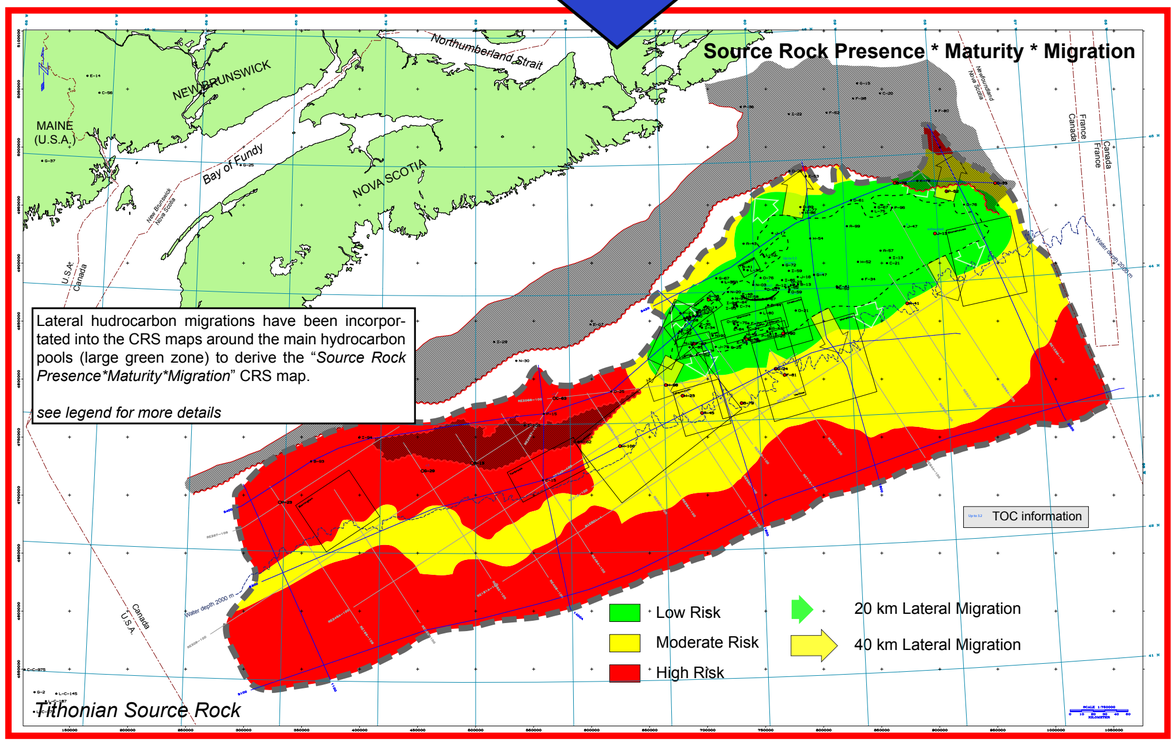
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011









PL. 8-2-16 **Tithonian Source Rock - CRS Mapping - Presence, Maturity and Migration**

PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

Source Rock Presence

The "*Source Rock Presence*" CRS map is controled by:
-well data (TOC / geochemistry)
-gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling)

TOC information

- Low Risk
- Moderate Risk
- High Risk

Valanginian Source Rock

*

Source Rock Presence * Maturity

The "*Source Rock Presence*" CRS map and the "*Source Rock Maturity Map*" CRS map are combined to derive a "*Source Rock Presence*Maturity*" CRS Map

TOC information

- Low Risk
- Moderate Risk
- High Risk

Valanginian Source Rock

Source Rock Maturity

The "*Source Rock Maturity*" CRS map is derived from Temis 3D basin modeling (Transfomration Ratio)

see legend for more details

TOC information

- Low Risk (Mature i.e. Transformation Ratio > 10% @ Present Time)
- Moderate Risk (Overmature i.e. Transformation Ratio > 95% @ Upper Cretaceous)
- High Risk (Non-mature i.e. Transformation Ratio < 10% @ Present Time)

Valanginian Source Rock

Source Rock Presence * Maturity * Migration

Lateral hudrocarbon migrations have been incorportated into the CRS maps around the main hydrocarbon pools (large green zone) to derive the "*Source Rock Presence*Maturity*Migration*" CRS map.

see legend for more details

TOC information

- Low Risk
- Moderate Risk
- High Risk
- 20 km Lateral Migration
- 40 km Lateral Migration

Valanginian Source Rock

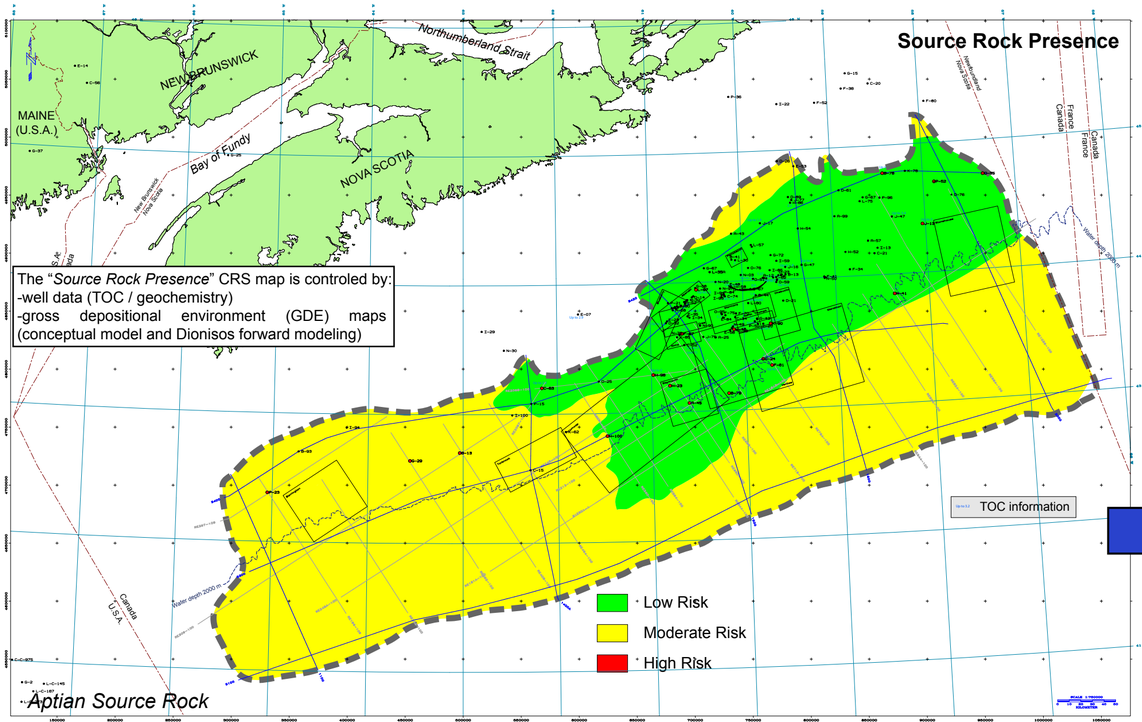
Valanginian Source Rock - CRS Mapping - Presence, Maturity and Migration **PL. 8-2-17**

PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

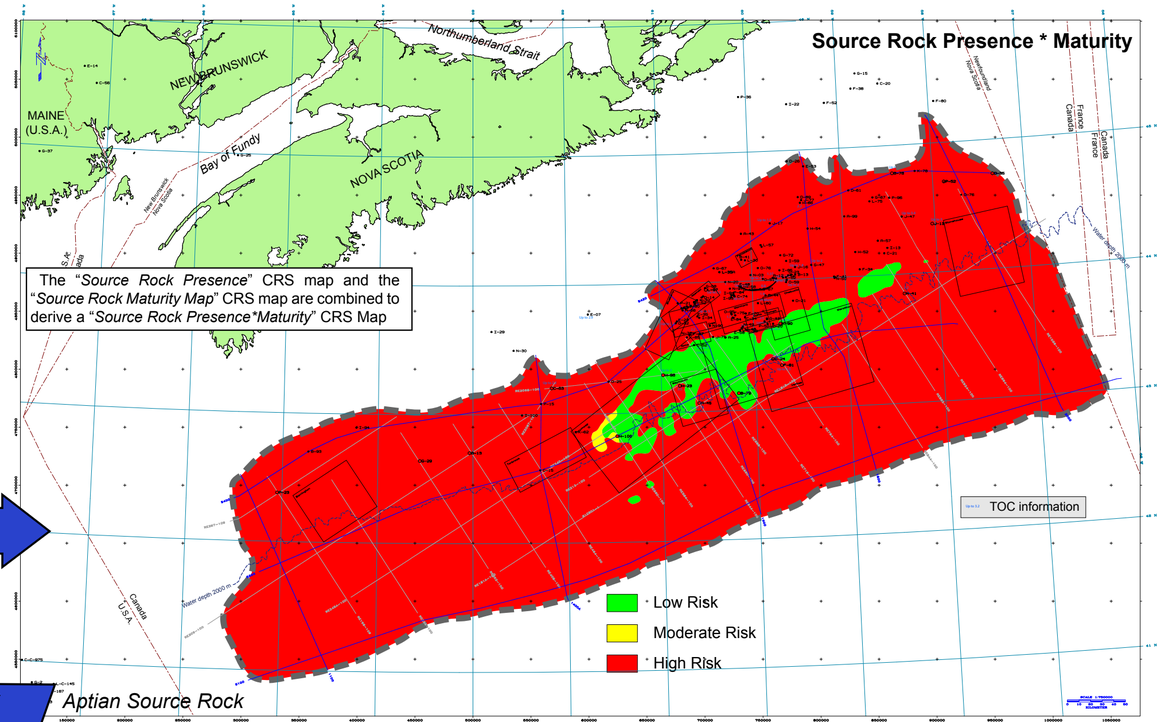
Source Rock Presence

The "*Source Rock Presence*" CRS map is controled by:
-well data (TOC / geochemistry)
-gross depositional environment (GDE) maps (conceptual model and Dionisos forward modeling)



Source Rock Presence * Maturity

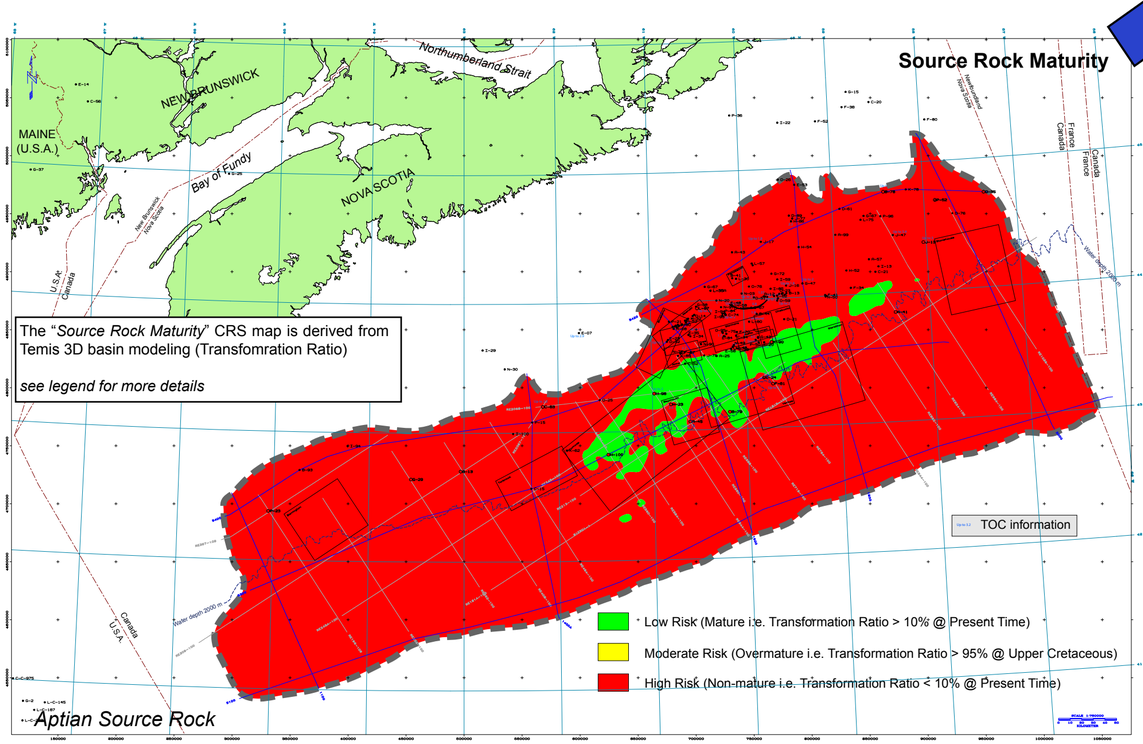
The "*Source Rock Presence*" CRS map and the "*Source Rock Maturity Map*" CRS map are combined to derive a "*Source Rock Presence***Maturity*" CRS Map



Source Rock Maturity

The "*Source Rock Maturity*" CRS map is derived from Temis 3D basin modeling (Transfomration Ratio)

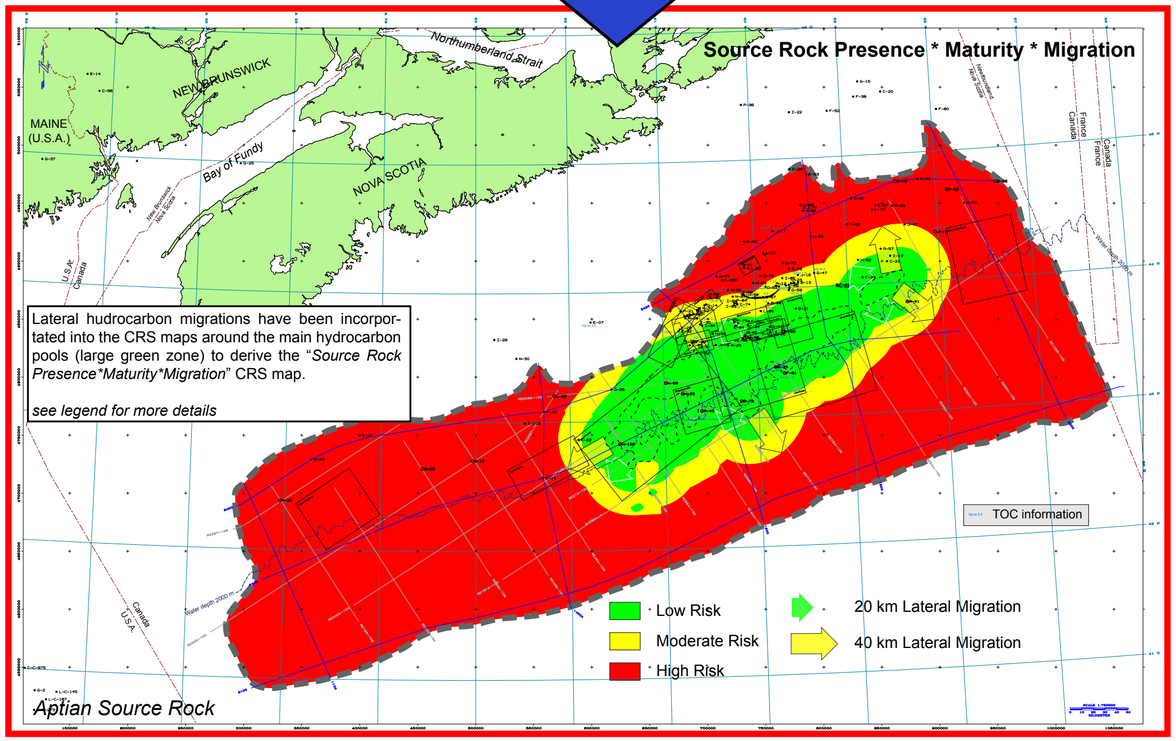
see legend for more details



Source Rock Presence * Maturity * Migration

Lateral hydrocarbon migrations have been incorportated into the CRS maps around the main hydrocarbon pools (large green zone) to derive the "*Source Rock Presence***Maturity***Migration*" CRS map.

see legend for more details



PL. 8-2-18 **Aptian Source Rock - CRS Mapping - Presence, Maturity and Migration**

PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

CRS - Source Rock Presence * Maturity * Migration

Source Rocks: Aptian / Valanginian / Tithonian / Callovian / Early Jurassic

Low Risk
Moderate Risk
High Risk

*

CRS - Source Rock Presence * Maturity * Migration

Source Rocks: Aptian / Valanginian / Tithonian / Callovian / Early Jurassic

Low Risk
Moderate Risk
High Risk

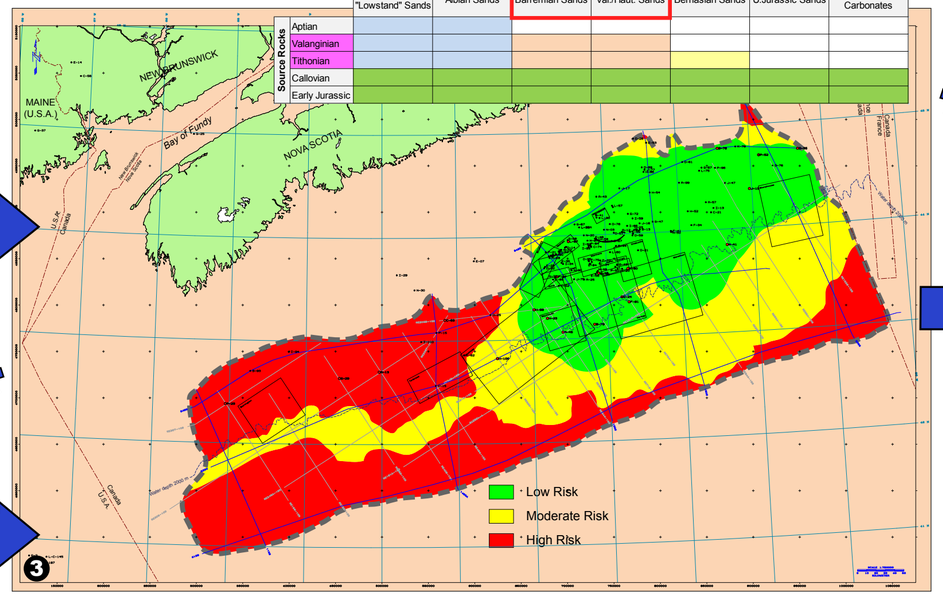
*

CRS - Source Rock Presence * Maturity * Migration

Source Rocks: Aptian / Valanginian / Tithonian / Callovian / Early Jurassic

Low Risk
Moderate Risk
High Risk

=



Source Rocks	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							

Plays

Source Rocks	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							

Plays

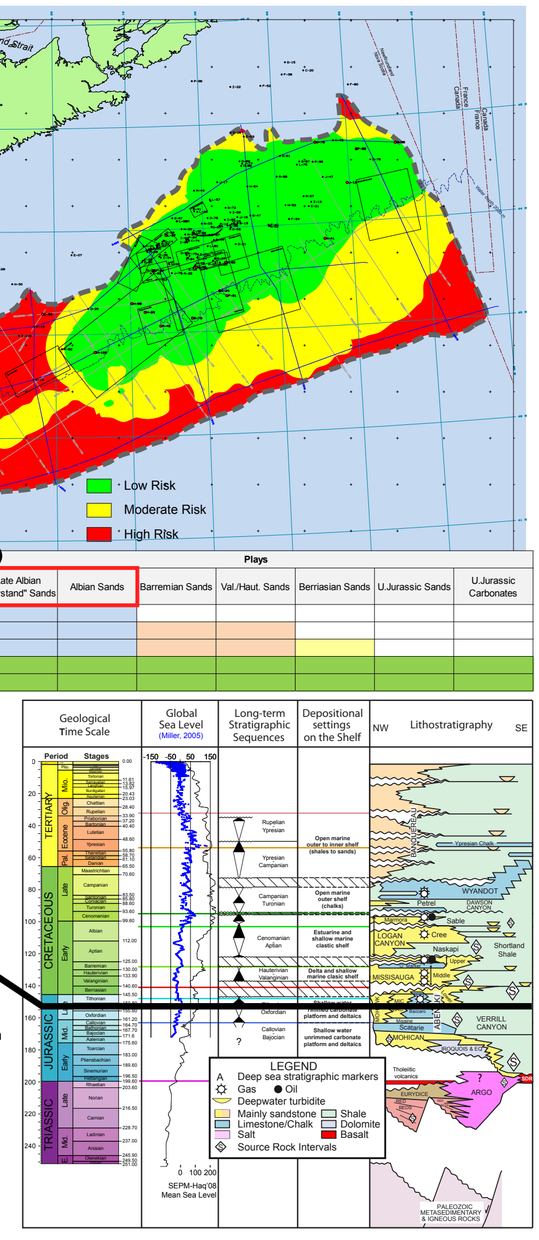
Source Rocks	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							

Upper Jurassic to Early Cretaceous Source Rock Petroleum System

4 Combined Aptian+Tithonian+Valanginian source rock petroleum system valid for Albian and Late Albian "Lowstand" Sands Plays

3 Combined Aptian+Tithonian+Valanginian source rock petroleum system valid for Albian and Late Albian "Lowstand" Sands Plays

2 Tithonian source rock petroleum system valid for Berriasian Sands Play



Early to Middle Jurassic Source Rock Petroleum System

1 Combined Early Jurassic + Callovian source rock petroleum system valid for all plays

Two source rock petroleum systems have been considered in the PFA study to map petroleum charge risk:

-The Early to Middle Jurassic Source Rock Petroleum System which includes both Early Jurassic and Callovian source rocks.
-The Upper Jurassic to Early Cretaceous Source Rock Petroleum System, which includes the Tithonian, Valanginian and Aptian source rocks.

They will be compiled with the reservoir and seal CRS maps of each play to summarize the play risks into final composite CRS maps in the next plates (Plates 8-2-20 to 8-2-26)

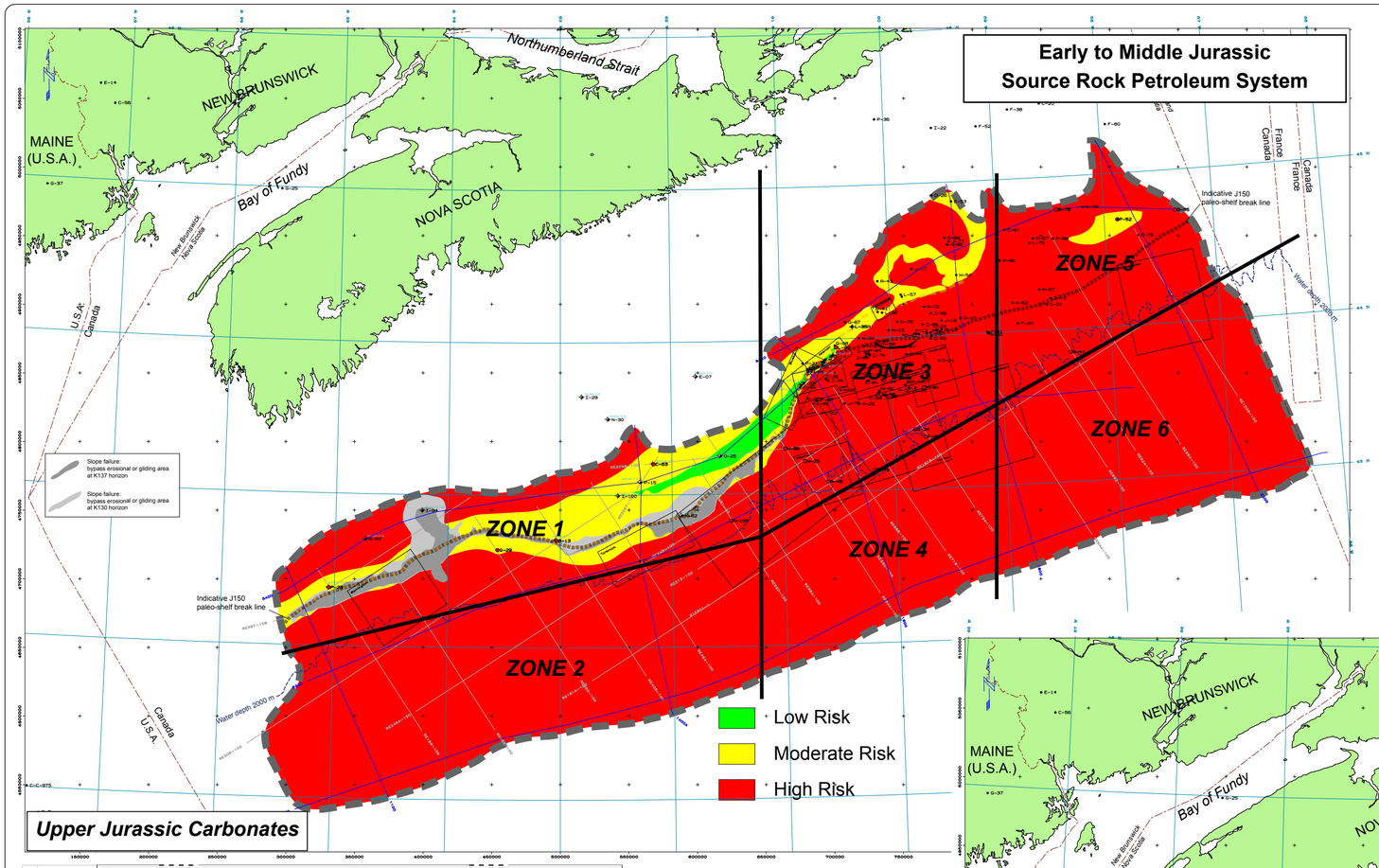
Source Rock Petroleum Systems - Composite CRS Mapping

PL. 8-2-19

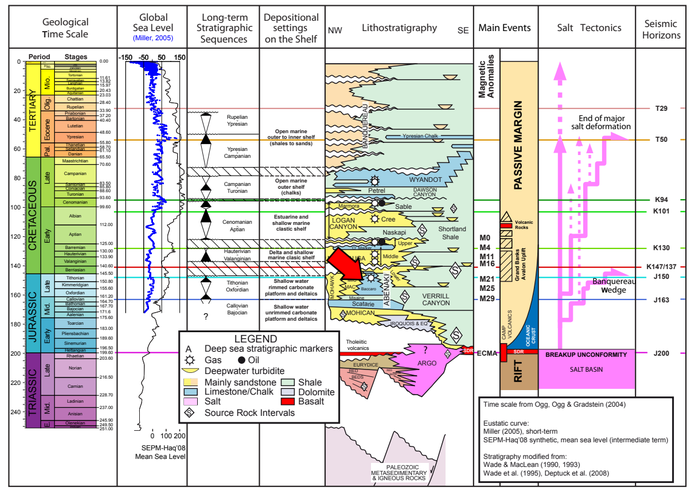
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

Early to Middle Jurassic Source Rock Petroleum System

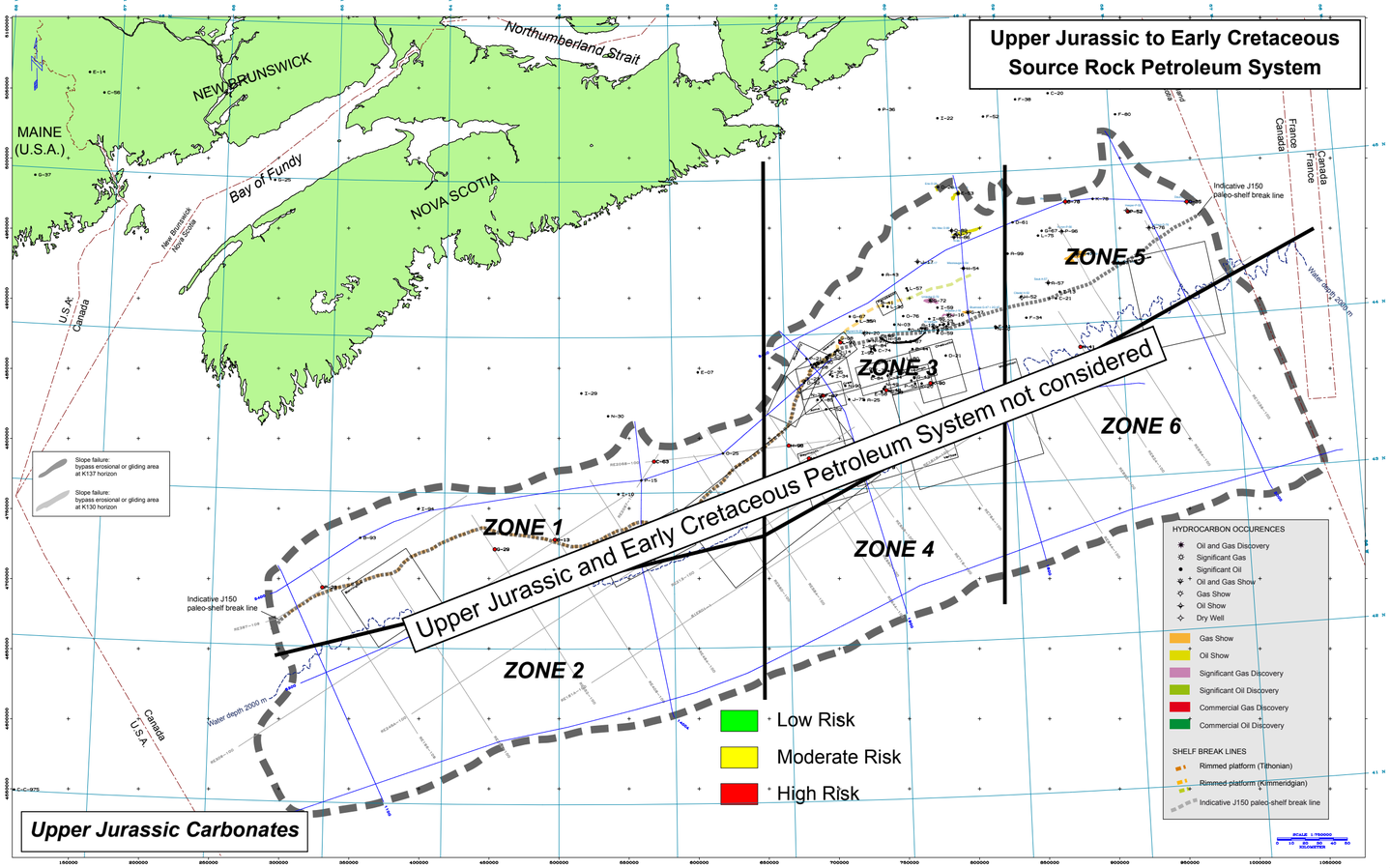


Source Rocks	Plays: Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							



Source Rocks	Plays: Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							

Upper Jurassic to Early Cretaceous Source Rock Petroleum System



The final composite CRS maps summarize the play risks in terms of:

-Reservoir presence and effectiveness,
-Seal presence and effectivennes
-Petroleum charge (source rock presence, maturation and laterla migration).

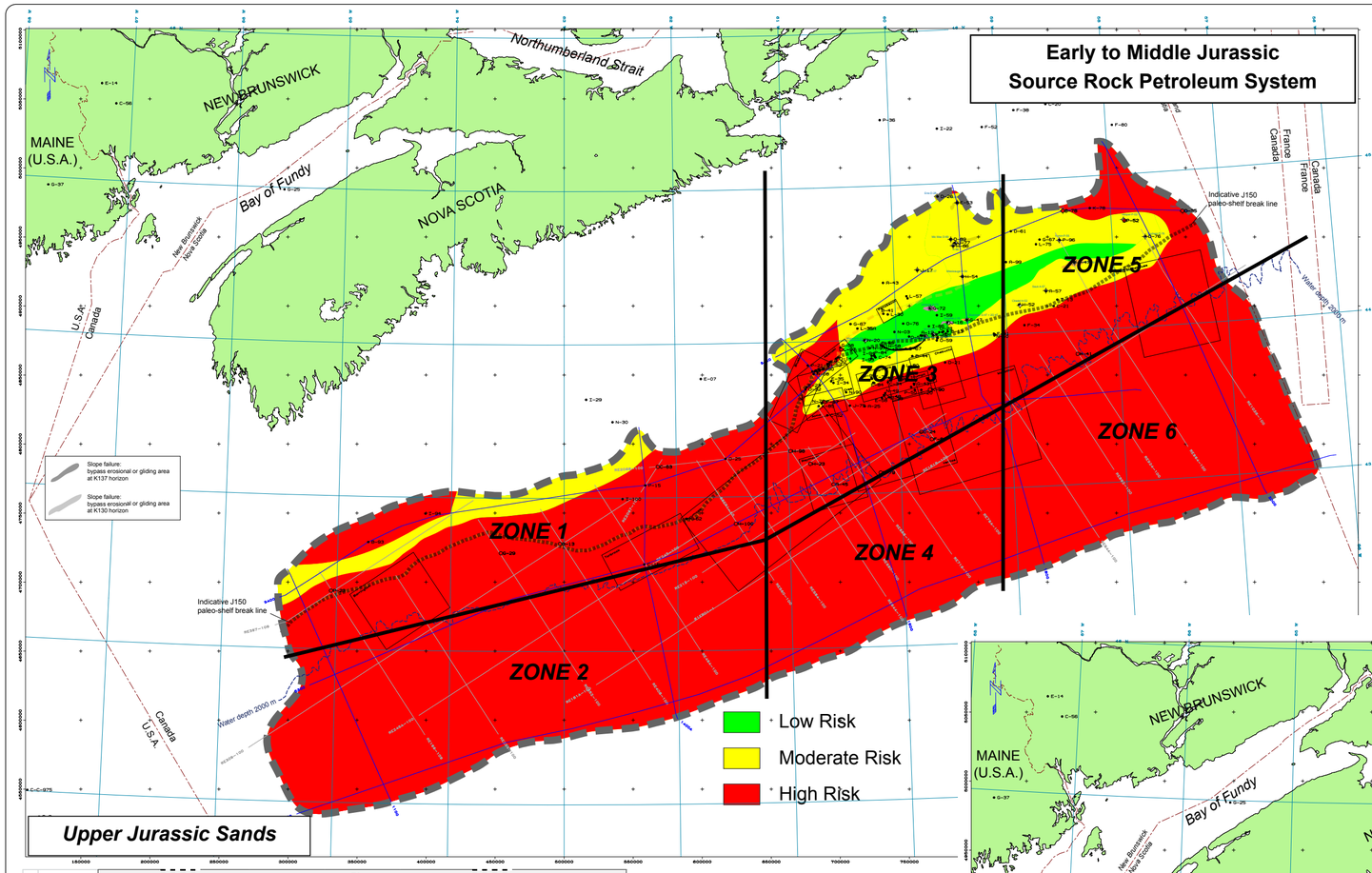
A set of two composite CRS maps has been generated for each play per source rock petroleum system

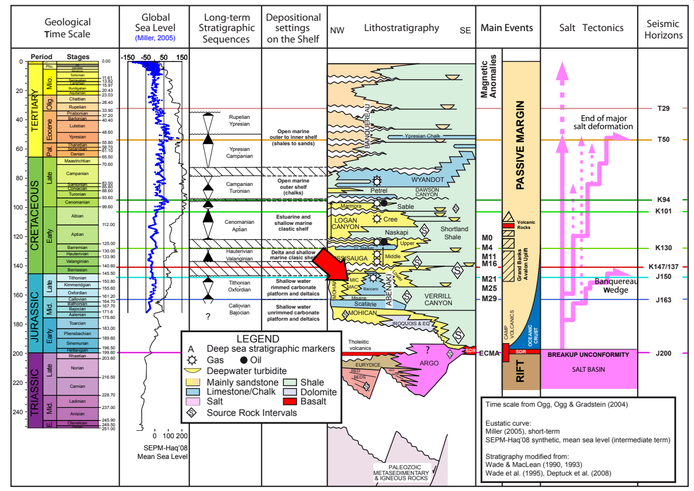
-Early to Middle Jurassic Source Rock Petroleum System
-Upper Jurassic to Early Cretaceous Source Rock Petroleum System

PL. 8-2-20 **Upper Jurassic Carbonate Play - Final Composite CRS Mapping**

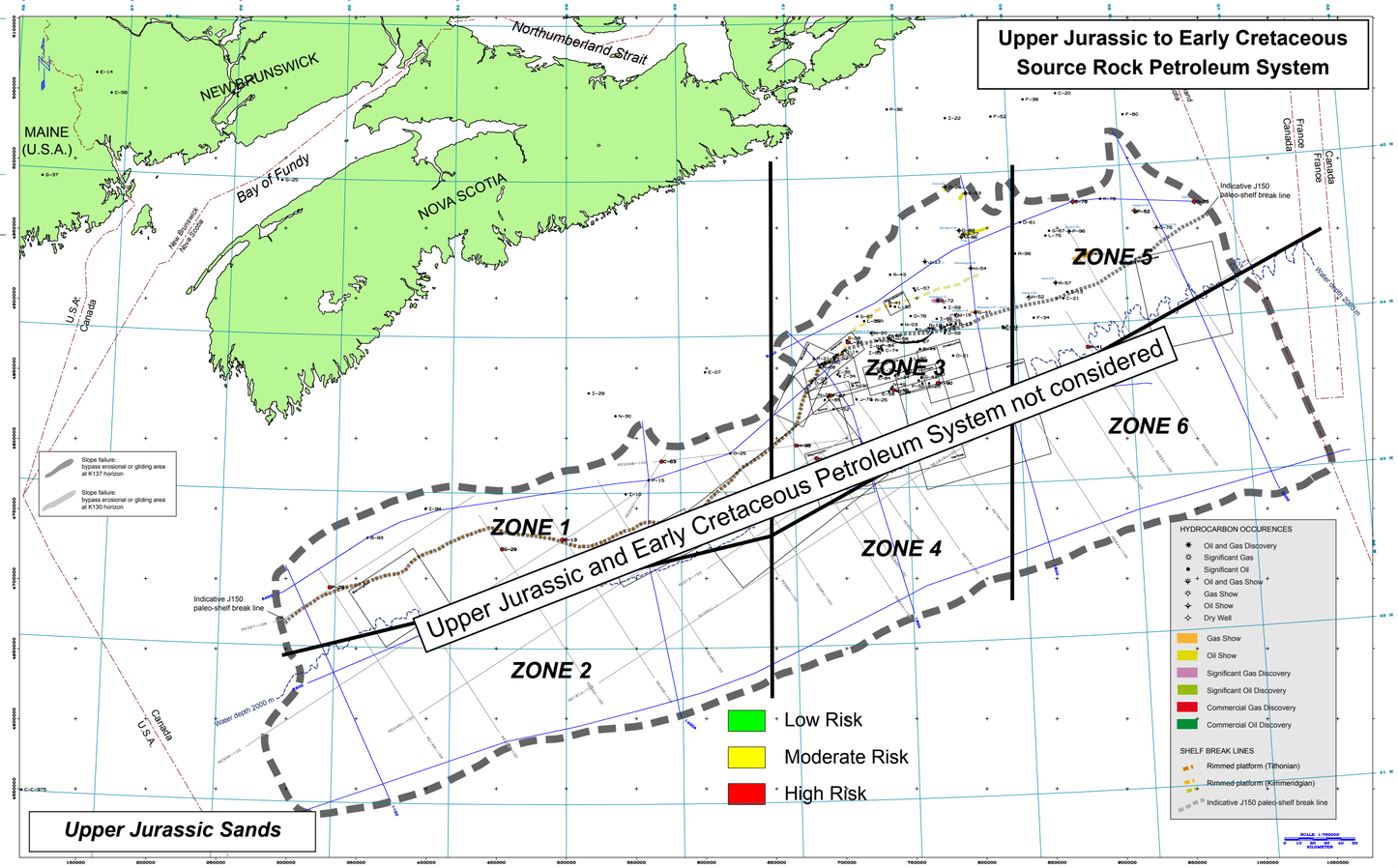
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011





Source Rocks	Plays						
	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							



Source Rocks	Plays						
	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							

The final composite CRS maps summarize the play risks in terms of:

-Reservoir presence and effectiveness,
-Seal presence and effectivennes
-Petroleum charge (source rock presence, maturation and laterla migration).

A set of two composite CRS maps has been generated for each play per source rock petroleum system

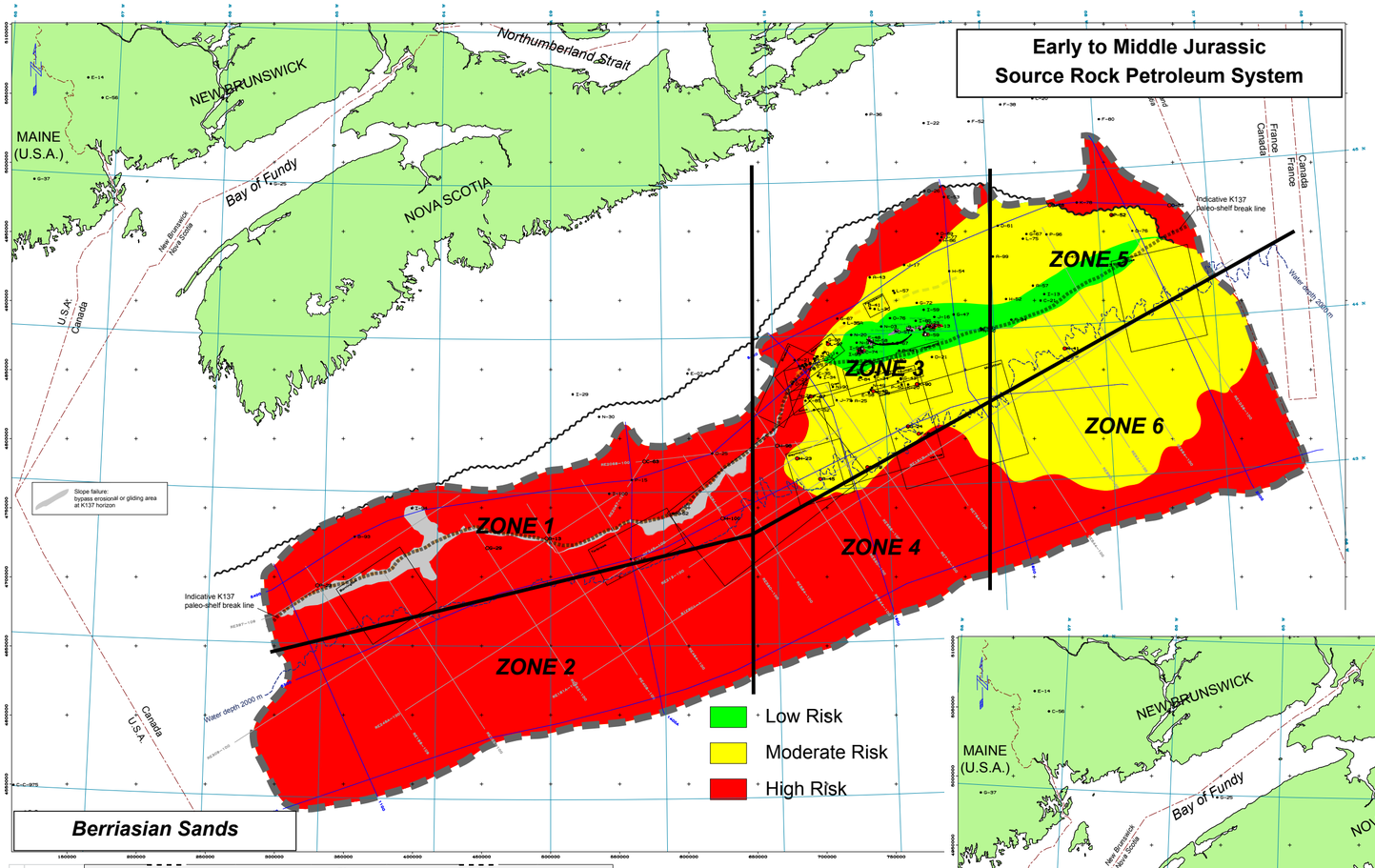
-Early to Middle Jurassic Source Rock Petroleum System
-Upper Jurassic to Early Cretaceous Source Rock Petroleum System

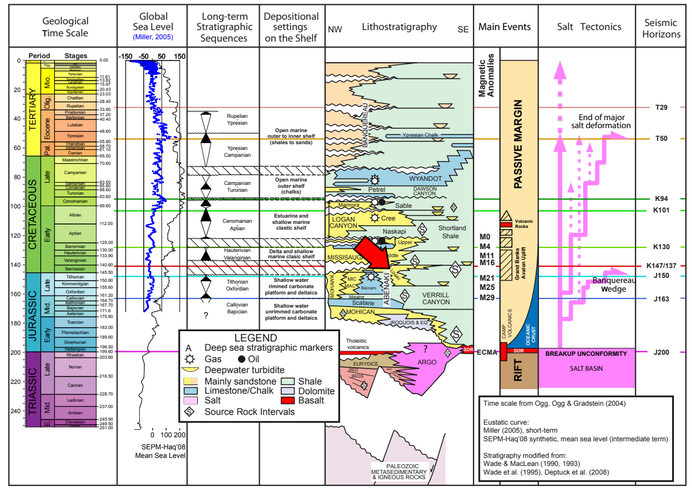
Upper Jurassic Sand Play - Final Composite CRS Mapping

PL. 8-2-21

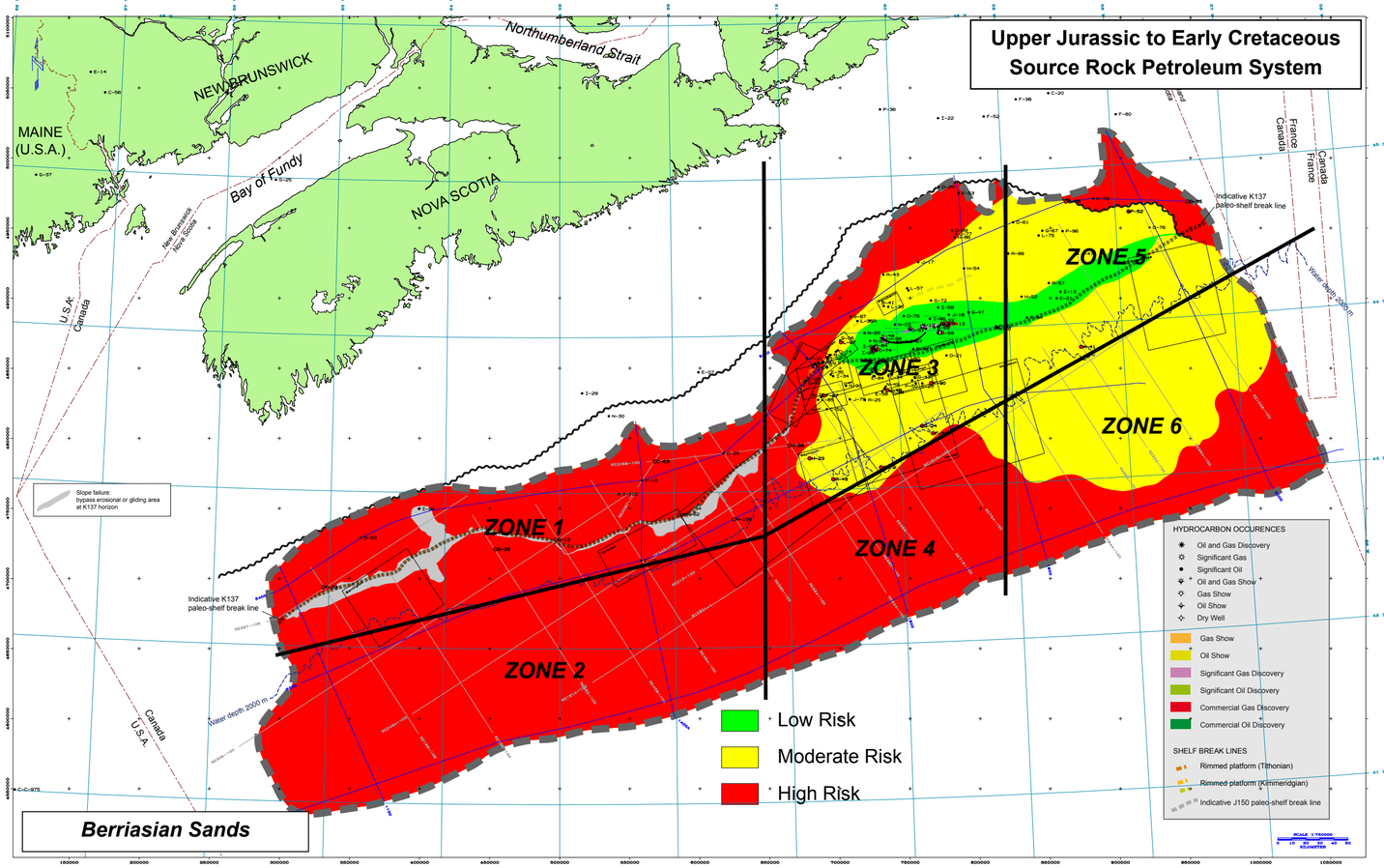
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011





Source Rocks	Plays						
	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							



The final composite CRS maps summarize the play risks in terms of:

-Reservoir presence and effectiveness,
-Seal presence and effectivennes
-Petroleum charge (source rock presence, maturation and laterla migration).

A set of two composite CRS maps has been generated for each play per source rock petroleum system

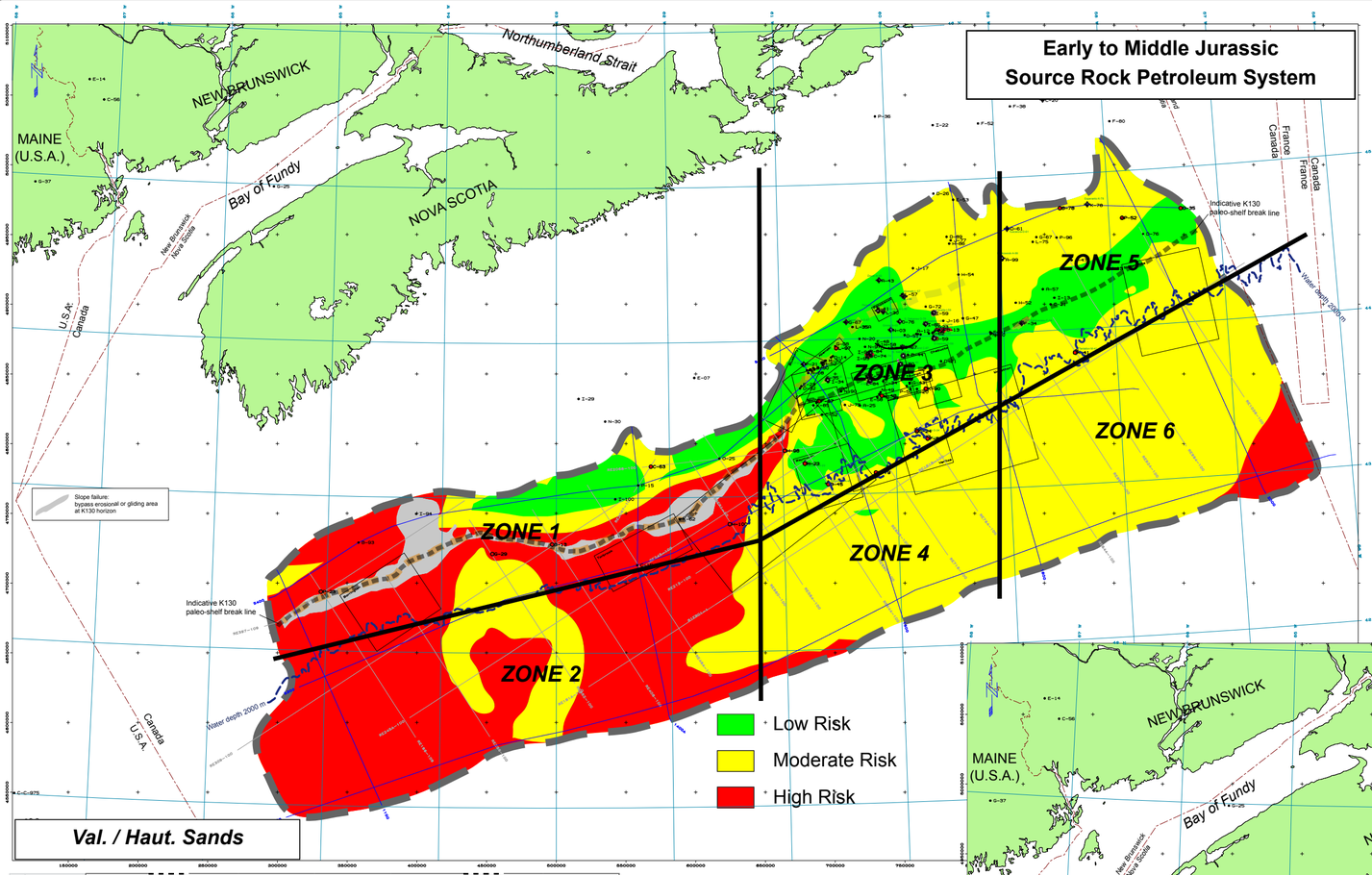
-Early to Middle Jurassic Source Rock Petroleum System
-Upper Jurassic to Early Cretaceous Source Rock Petroleum System

PL. 8-2-22 **Berriasian Sand Play - Final Composite CRS Mapping**

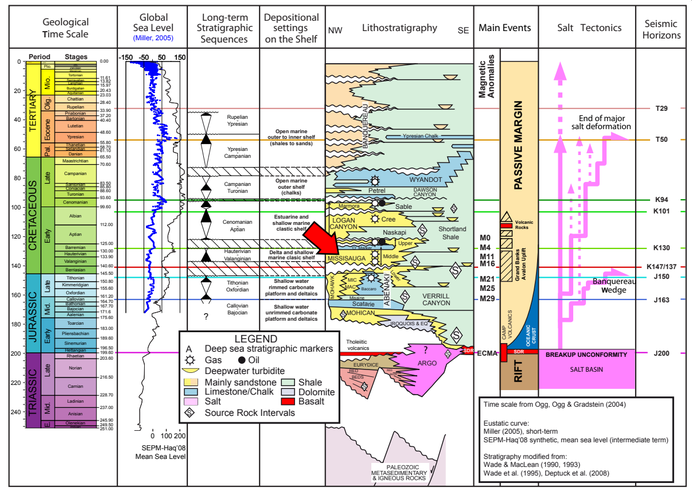
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

Early to Middle Jurassic Source Rock Petroleum System

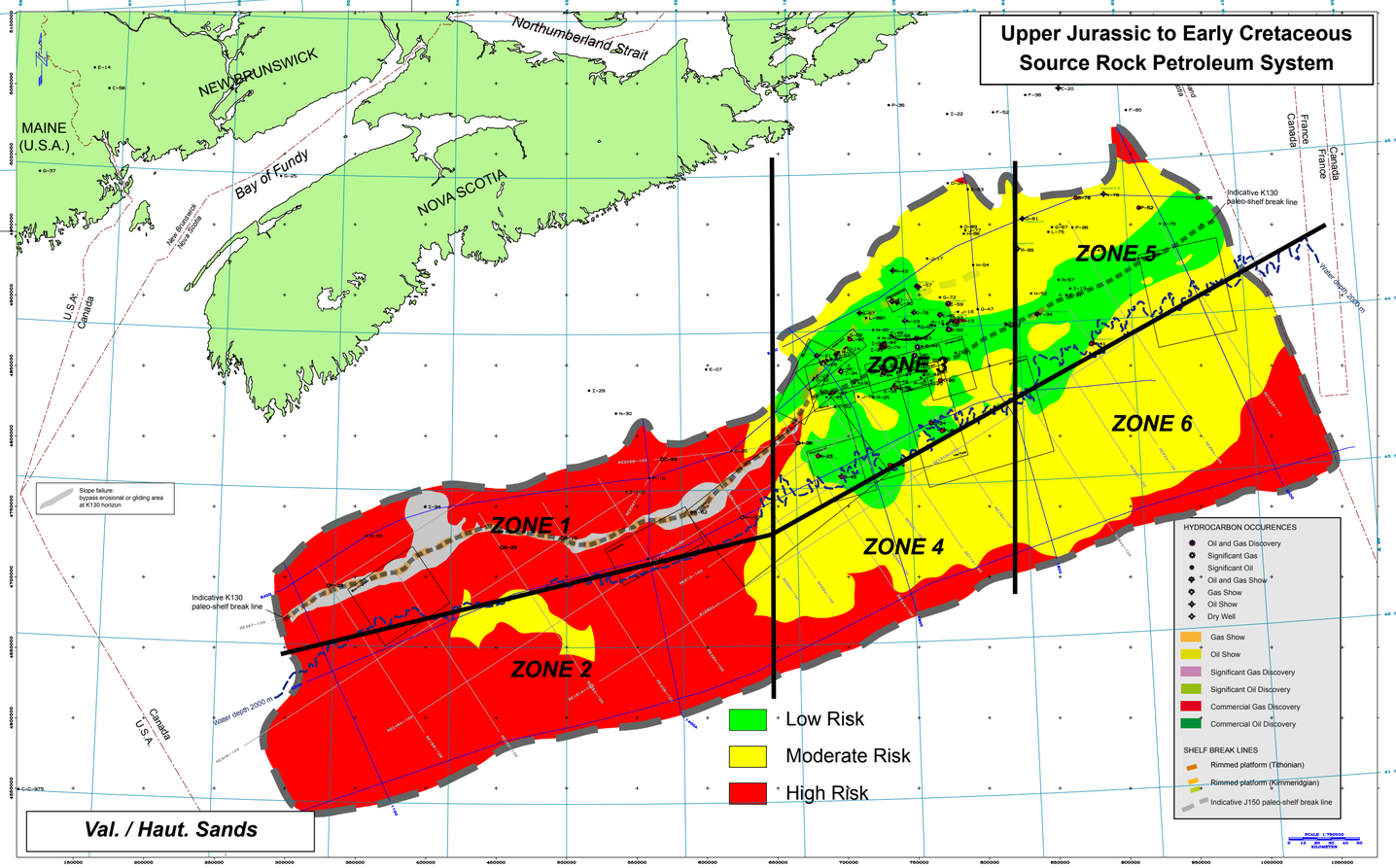


Source Rocks	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							



Source Rocks	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							

Upper Jurassic to Early Cretaceous Source Rock Petroleum System



The final composite CRS maps summarize the play risks in terms of:

-Reservoir presence and effectiveness,
-Seal presence and effectivennes
-Petroleum charge (source rock presence, maturation and laterla migration).

A set of two composite CRS maps has been generated for each play per source rock petroleum system

-Early to Middle Jurassic Source Rock Petroleum System
-Upper Jurassic to Early Cretaceous Source Rock Petroleum System

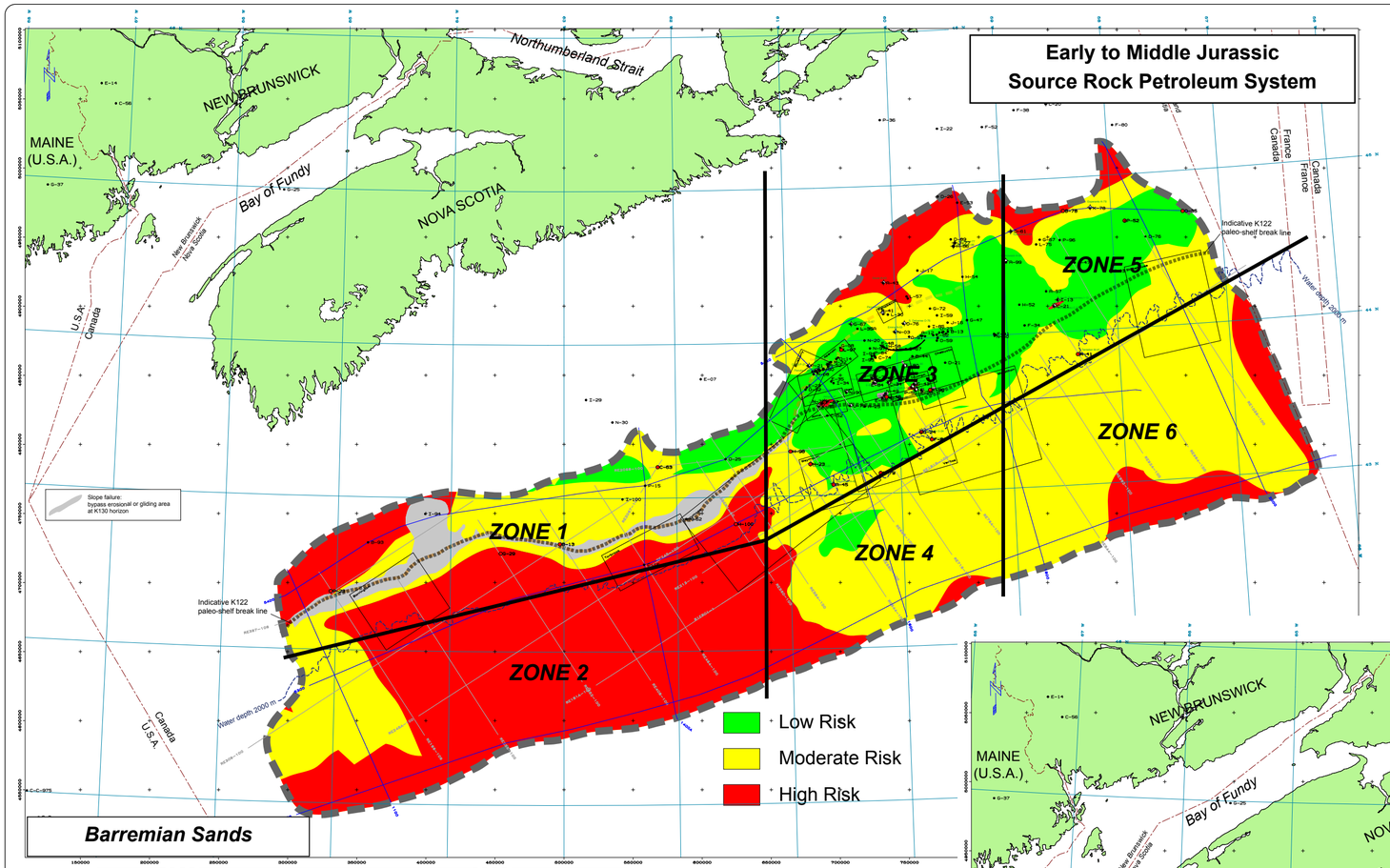
Valanginian / Hauterivian Sand Play - Final Composite CRS Mapping

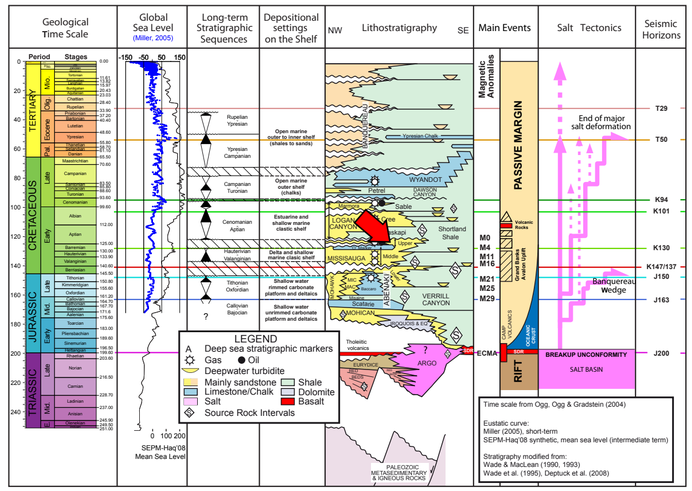
PL. 8-2-23

PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

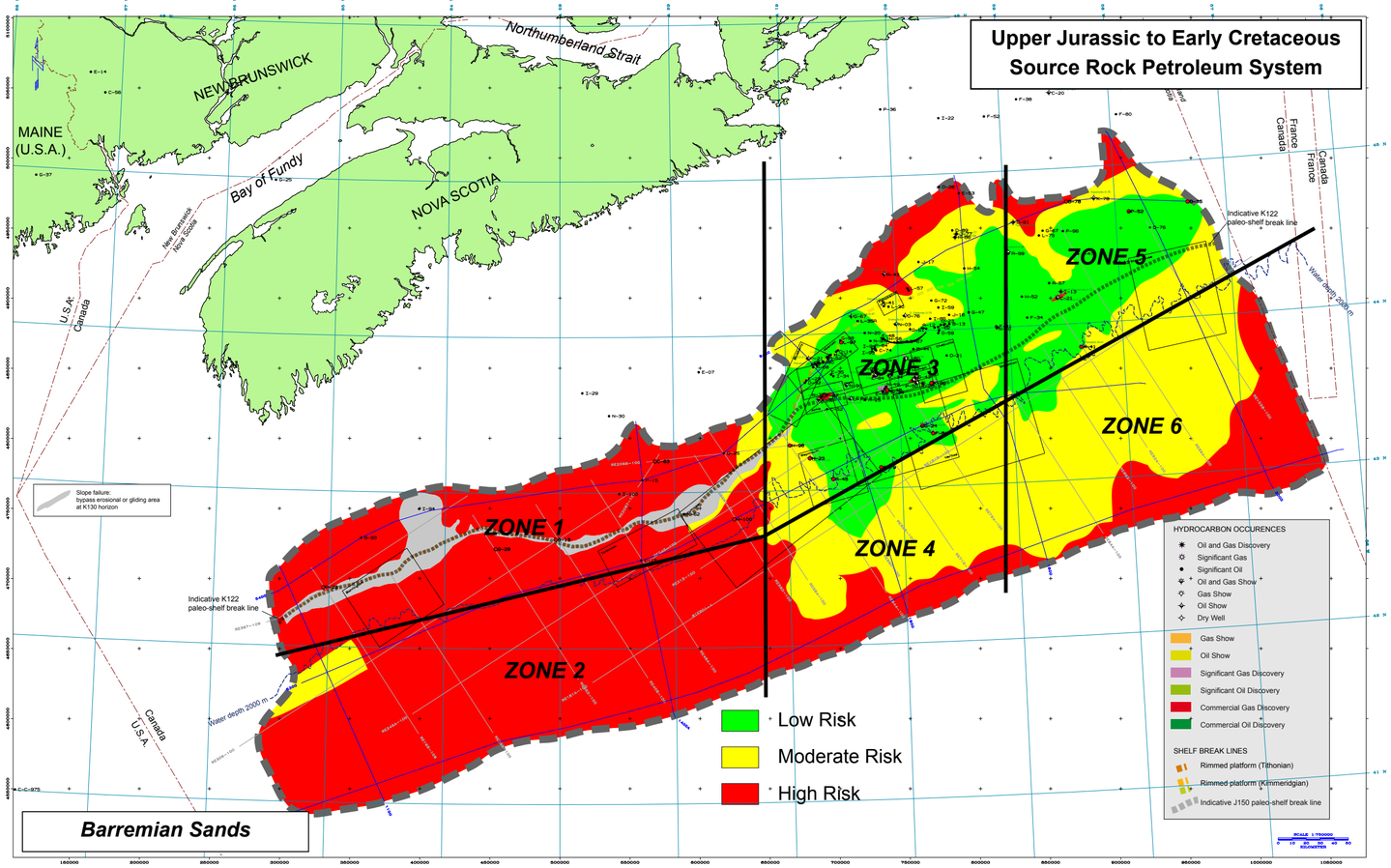
Early to Middle Jurassic Source Rock Petroleum System





Source Rocks	Plays						
	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							

Upper Jurassic to Early Cretaceous Source Rock Petroleum System



Source Rocks	Plays						
	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							

The final composite CRS maps summarize the play risks in terms of:

-Reservoir presence and effectiveness,
-Seal presence and effectivennes
-Petroleum charge (source rock presence, maturation and laterla migration).

A set of two composite CRS maps has been generated for each play per source rock petroleum system

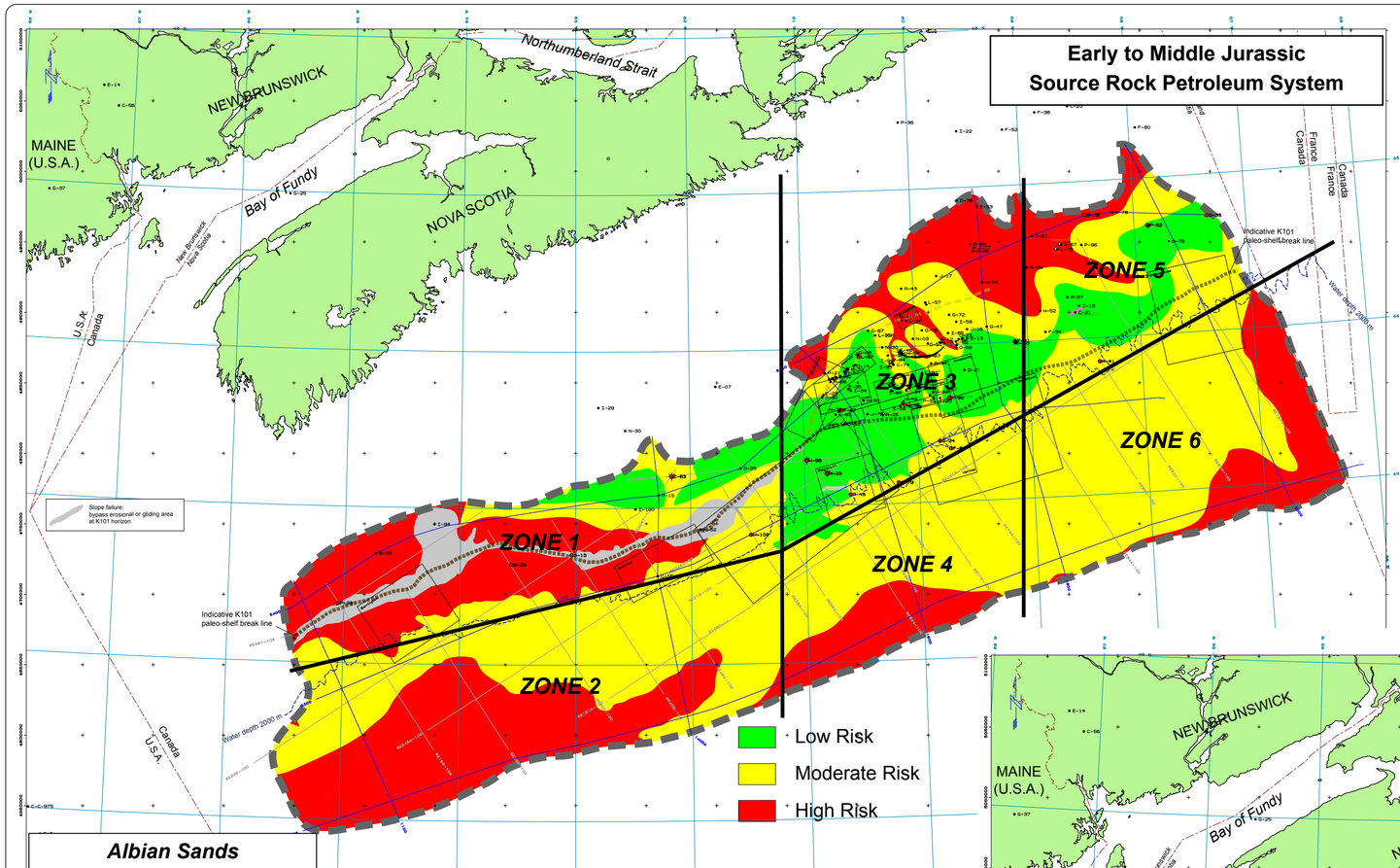
-Early to Middle Jurassic Source Rock Petroleum System
-Upper Jurassic to Early Cretaceous Source Rock Petroleum System

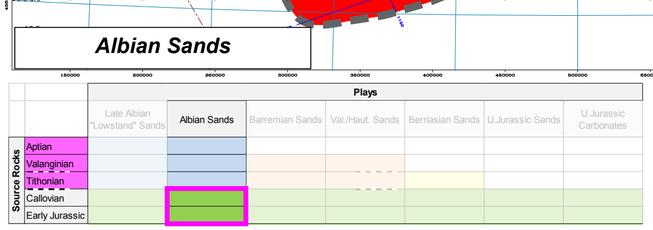
PL. 8-2-24 **Barremian Sand Play - Final Composite CRS Mapping**

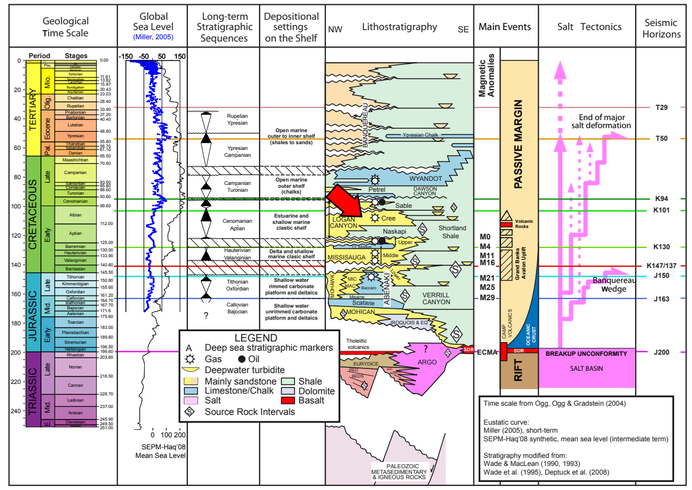
PETROLEUM EVALUATION - CRS MAPPING

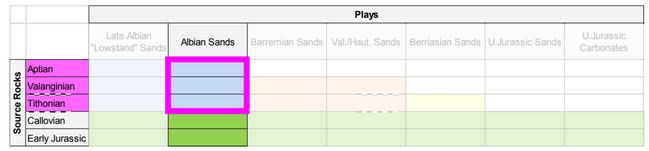
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

Early to Middle Jurassic Source Rock Petroleum System

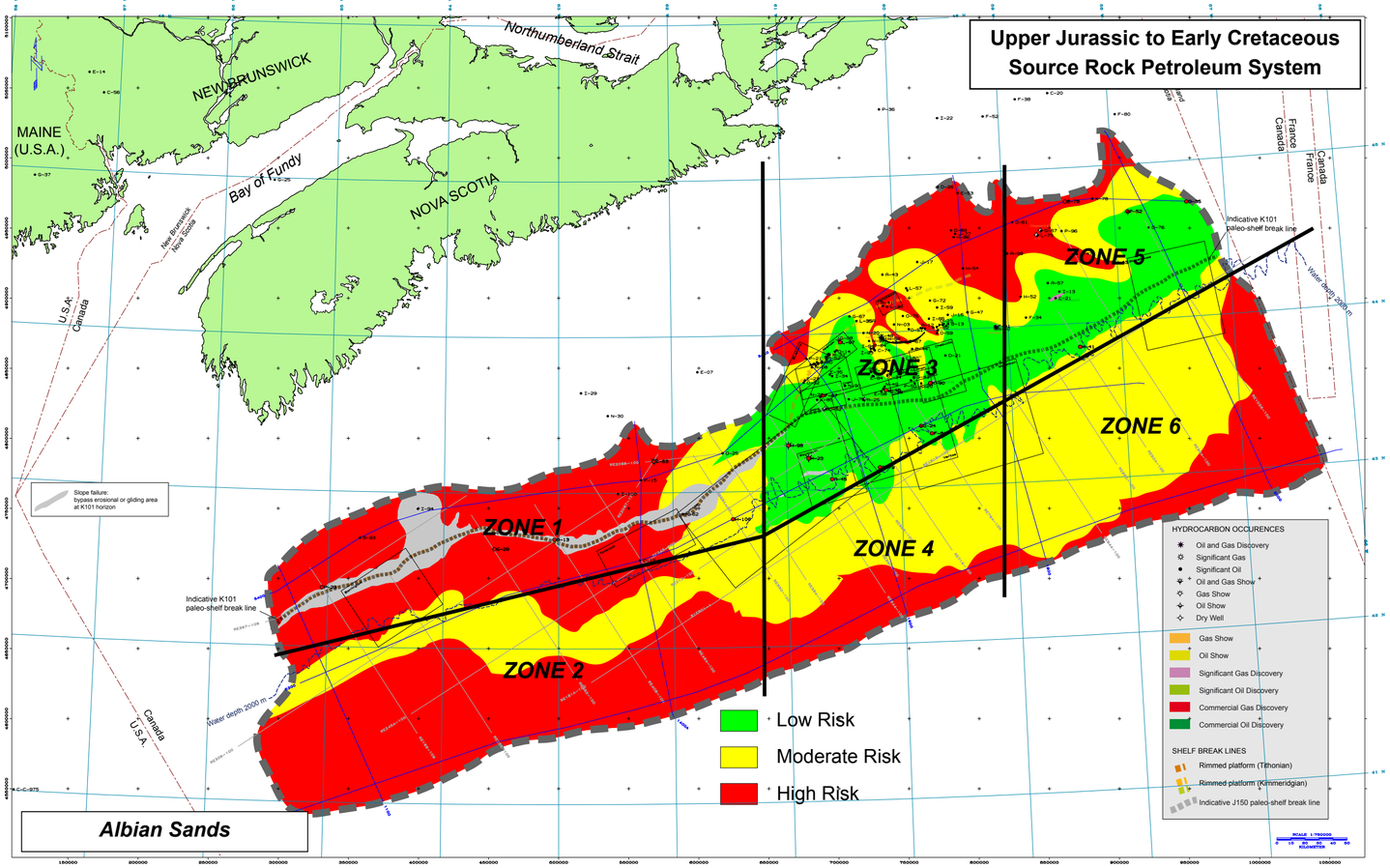








Upper Jurassic to Early Cretaceous Source Rock Petroleum System



The final composite CRS maps summarize the play risks in terms of:

-Reservoir presence and effectiveness,
-Seal presence and effectivennes
-Petroleum charge (source rock presence, maturation and laterla migration).

A set of two composite CRS maps has been generated for each play per source rock petroleum system

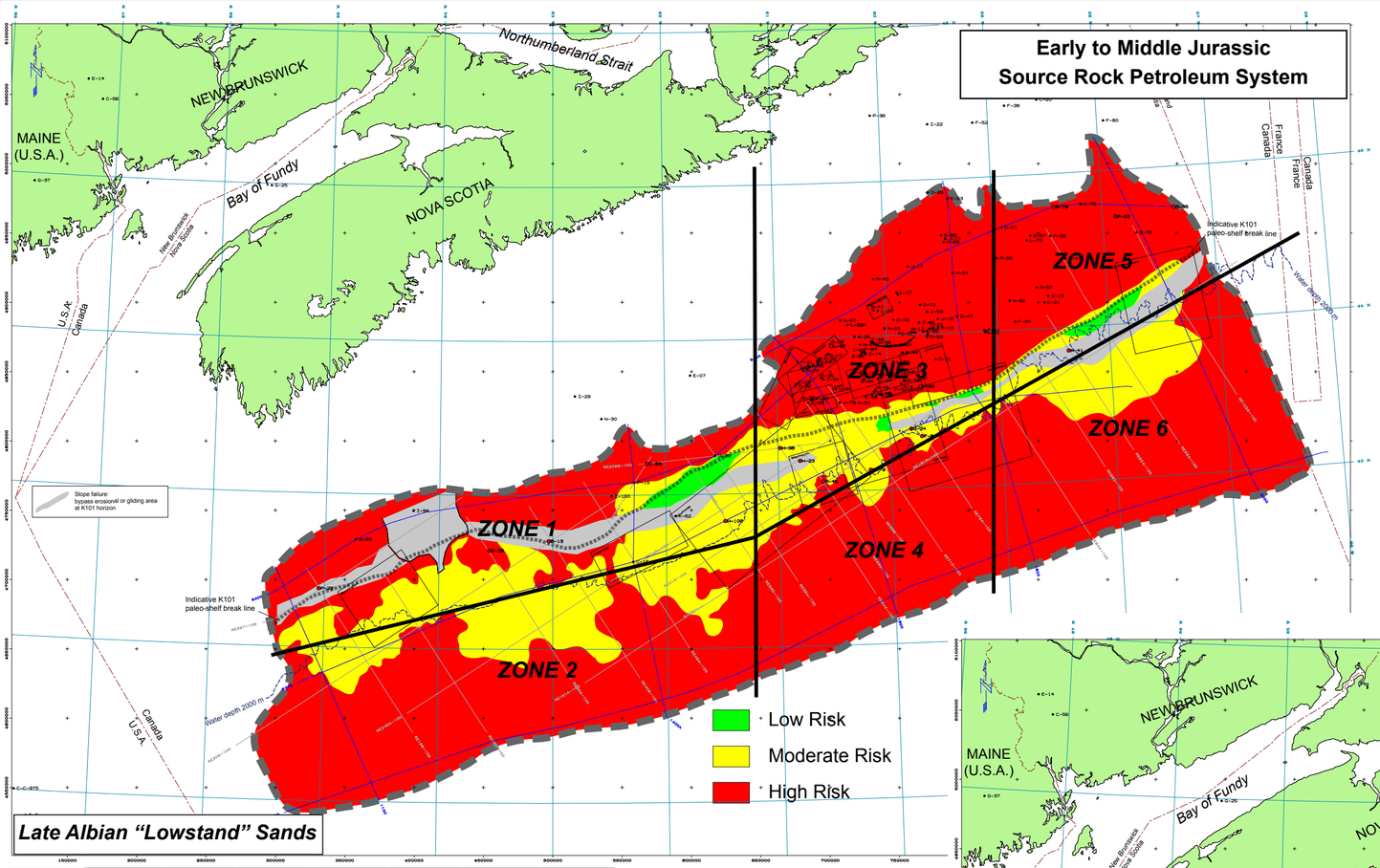
-Early to Middle Jurassic Source Rock Petroleum System
-Upper Jurassic to Early Cretaceous Source Rock Petroleum System

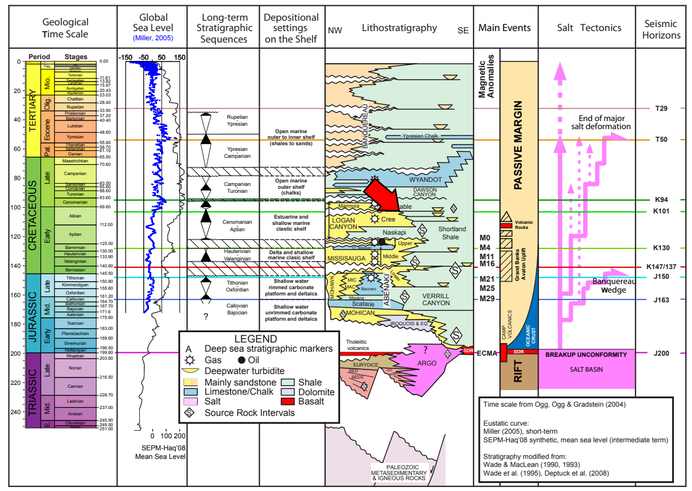
Albian Sand Play - Final Composite CRS Mapping

PL. 8-2-25

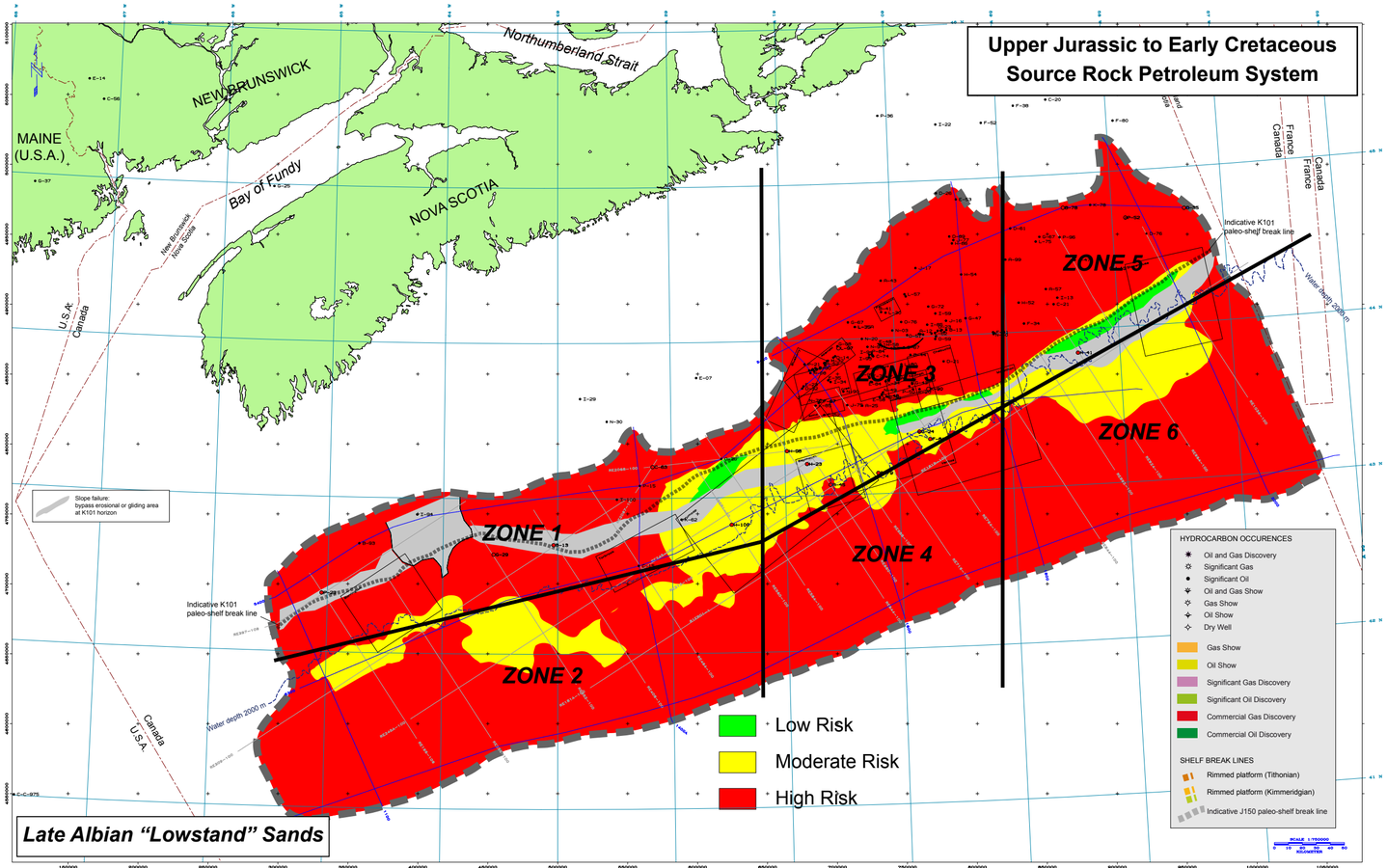
PETROLEUM EVALUATION - CRS MAPPING

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011





Source Rocks	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							



Source Rocks	Late Albian "Lowstand" Sands	Albian Sands	Barremian Sands	Val./Haut. Sands	Berriasian Sands	U.Jurassic Sands	U.Jurassic Carbonates
Aptian							
Valanginian							
Tithonian							
Callovian							
Early Jurassic							

The final composite CRS maps summarize the play risks in terms of:

-Reservoir presence and effectiveness,
-Seal presence and effectivennes
-Petroleum charge (source rock presence, maturation and laterla migration).

A set of two composite CRS maps has been generated for each play per source rock petroleum system

-Early to Middle Jurassic Source Rock Petroleum System
-Upper Jurassic to Early Cretaceous Source Rock Petroleum System

PL. 8-2-26 **Late Albian "Lowstand" Sand Play - Final Composite CRS Mapping**

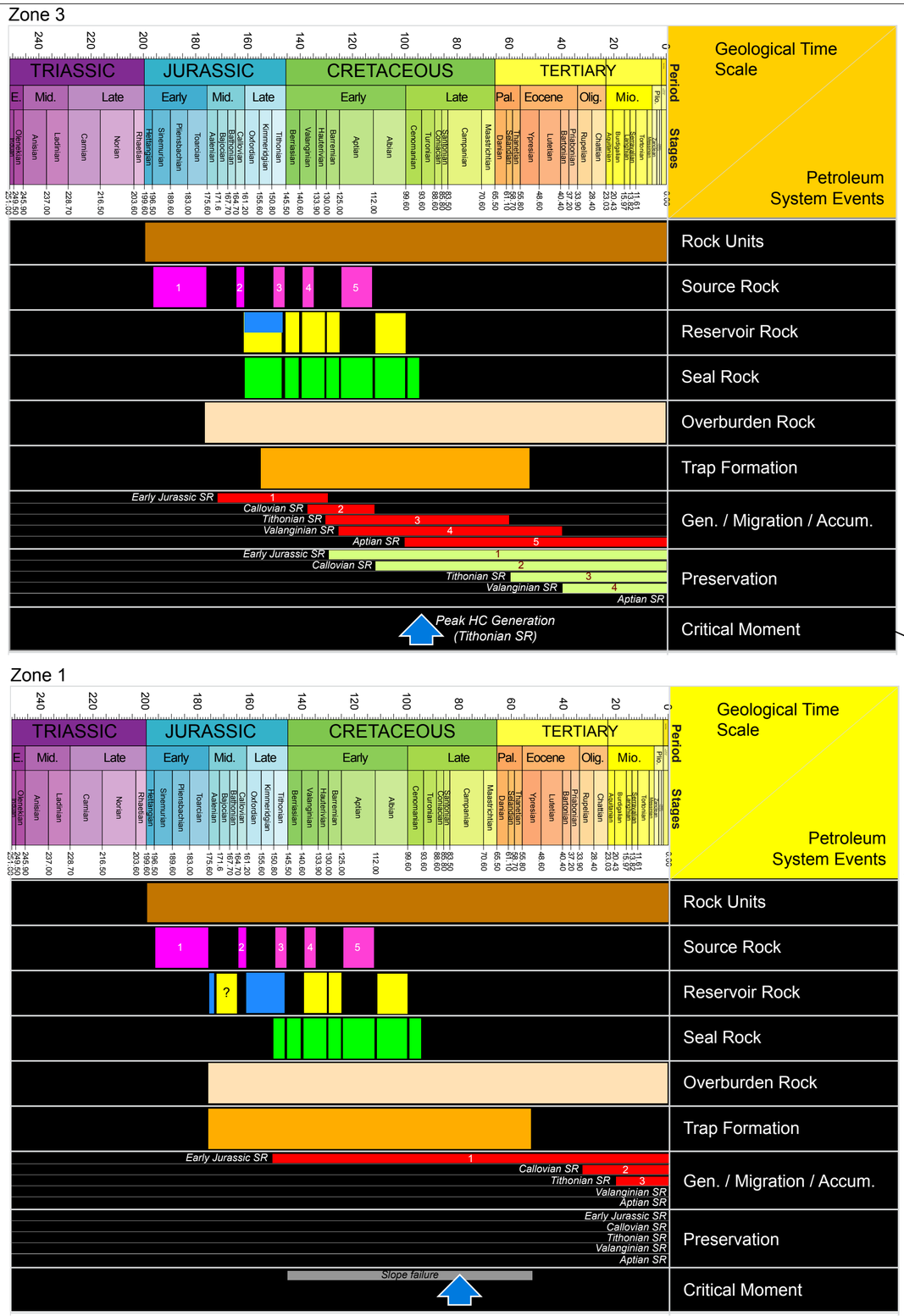
CHAPTER 8-3

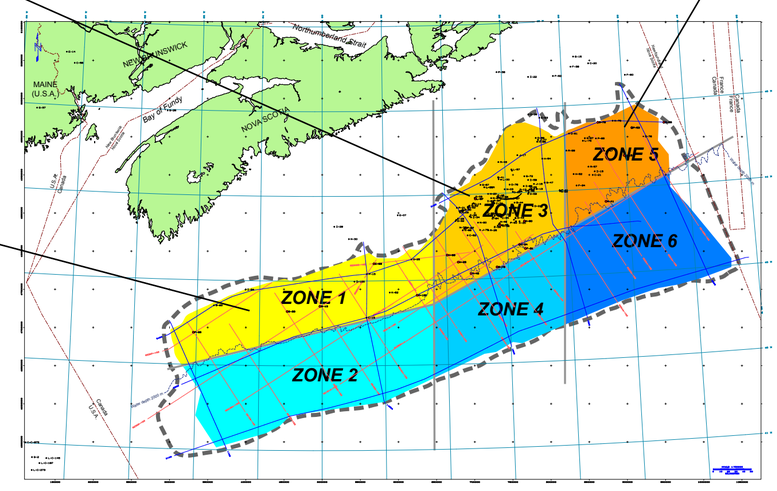
PETROLEUM EVALUATION

EVENT CHARTS

PETROLEUM EVALUATION - PETROLEUM EVENT CHARTS

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011





Trap formation:

Traps were formed from Early Jurassic to present. On the shelf and slope area (zones 1, 3 and 5), most of the traps developed from Early Jurassic up to Eocene.

In zones 3 and 5, most of the traps are growth fault related traps. Younger traps are mainly related to salt diapirism.

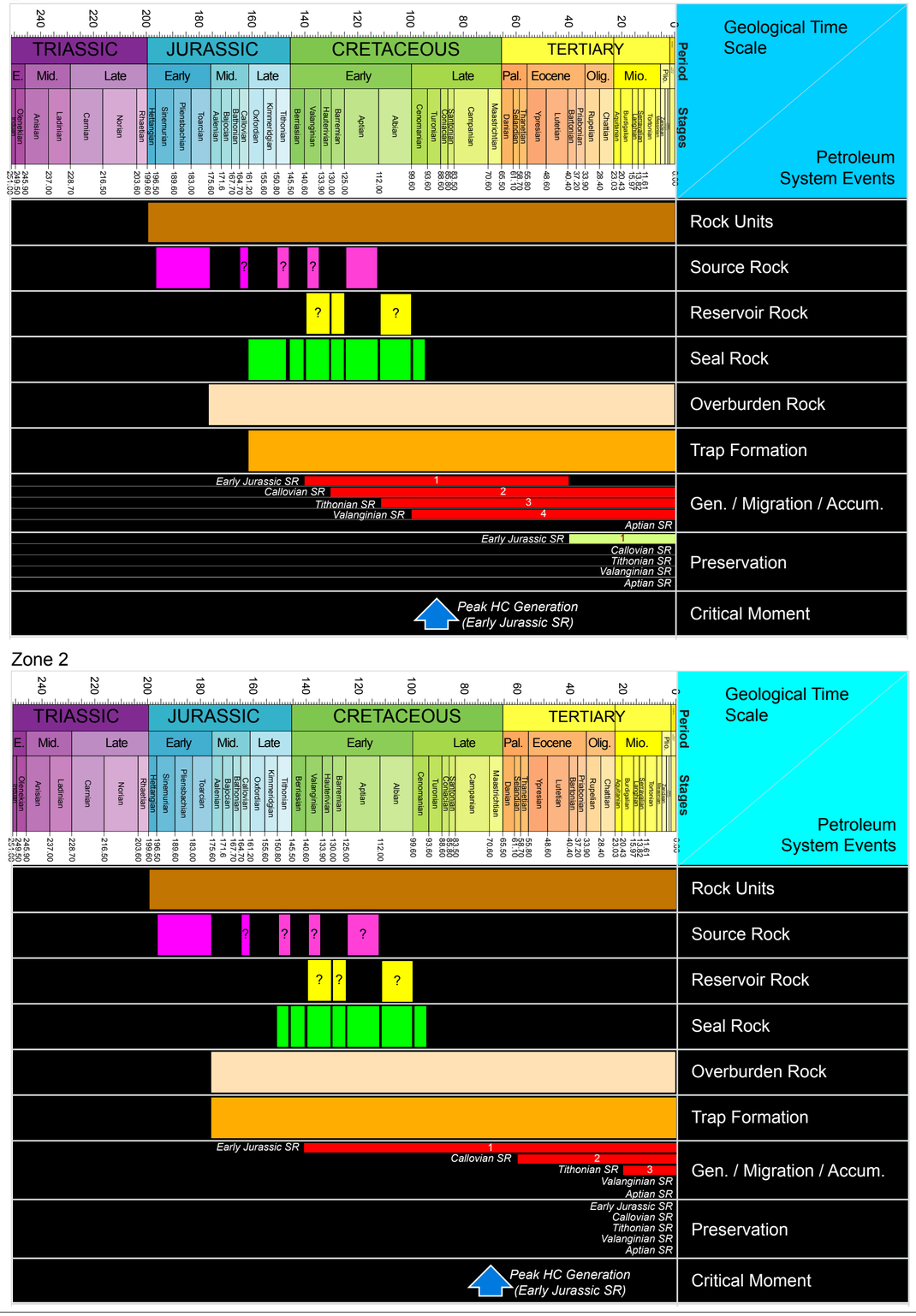
Growth faults related traps (zones 3 and 5) mainly formed from Mid-Jurassic to Early Cretaceous (before the peak of hydrocarbon generation) even if the faults remain active up to Eocene times. Younger traps could have occured later than the main generation and migration of hydrocarbons.

PL. 8-3-1 **Petroleum System Event Charts - Shelf and Slope Areas - Zones 1, 3 and 5**

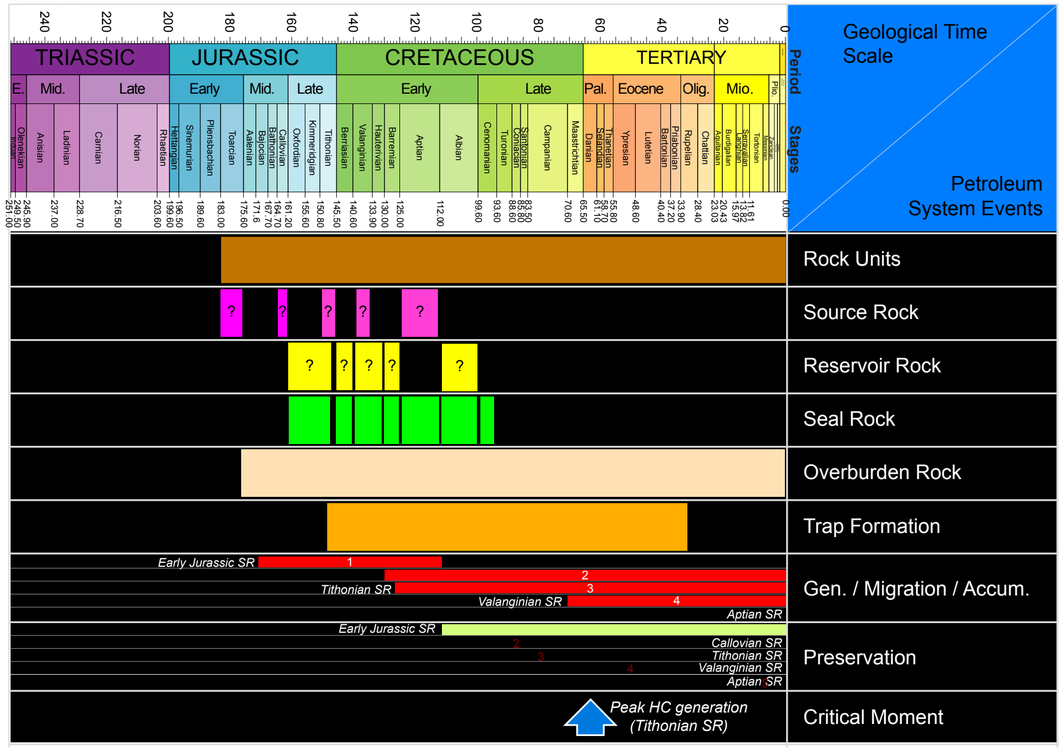
PETROLEUM EVALUATION - PETROLEUM EVENT CHARTS

PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

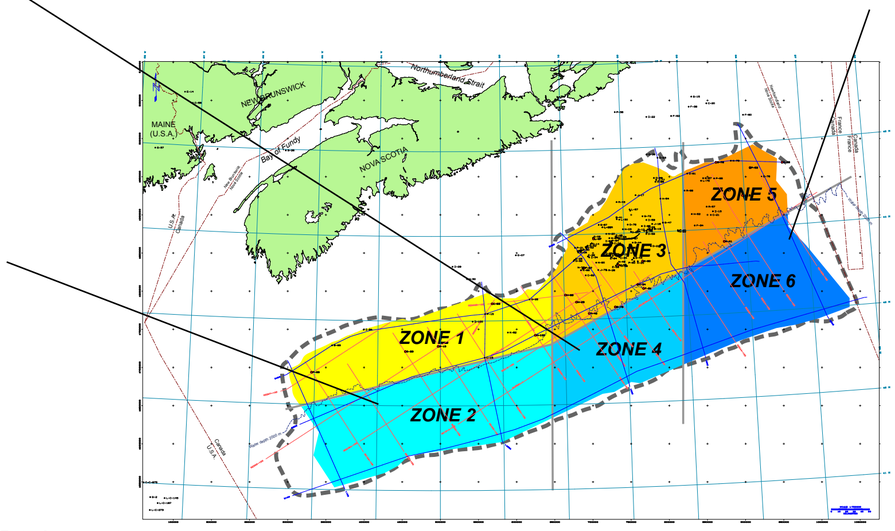
Zone 4



Zone 6



Zone 2



Petroleum systems

The peak of hydrocarbon generation always occured later than the deposition of reservoir and seal rocks.

In zone 1, a continuous slope failure (bypass erosion gliding) occured during Cretaceous and Early Tertiary with a paroxysmal event dated Ypresian time (Montagnais event). This process implies reduced sealing effectiveness for the Jurassic Carbonate play.

In zone 1, the petroleum system completely depends on the Early Jurassic source rock presence.

In zones 3 and 5, all the elements and processes are present. The petroleum systems have passed their hydrocarbon peak generation.

Oolitic limestones and possible Mid Jurassic sands could be present in the Mohican graben area and can be charged by the contiguous Early Jurassic source rocks

CHAPTER 8-4

PETROLEUM EVALUATION

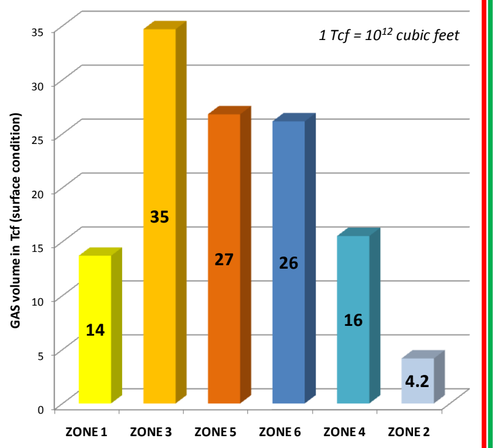
HYDROCARBON VOLUMES

PETROLEUM EVALUATION - HYDROCARBON VOLUMES

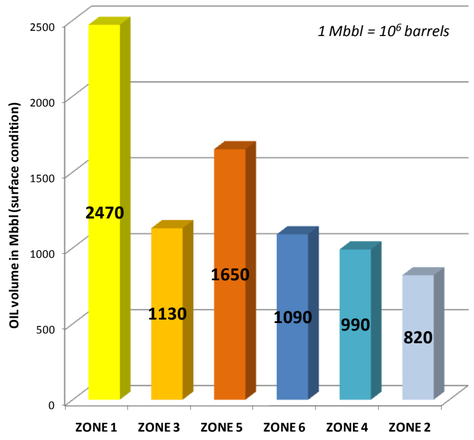
PLAY FAIRWAY ANALYSIS - OFFSHORE NOVA SCOTIA - CANADA - June 2011

GRAND TOTAL

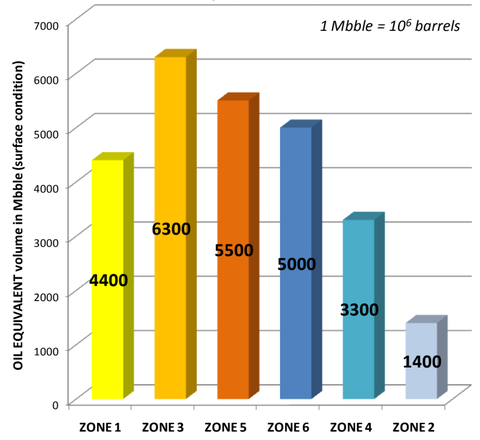
GAS



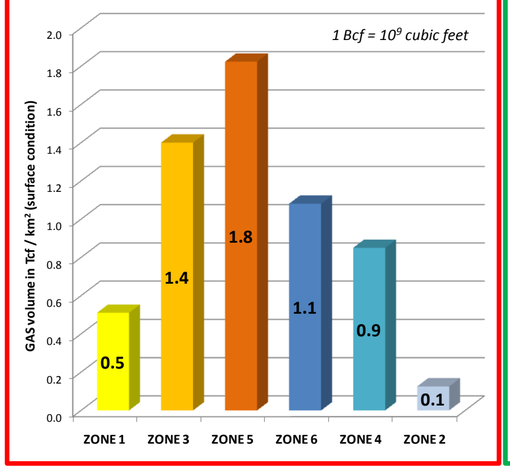
OIL

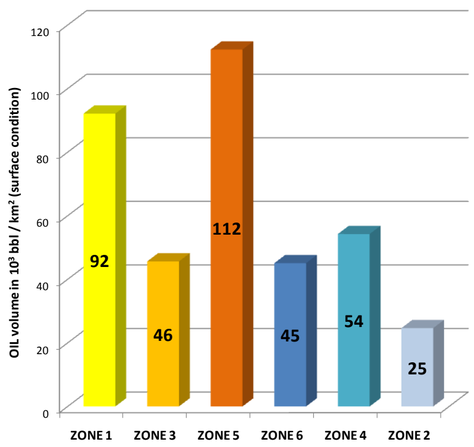


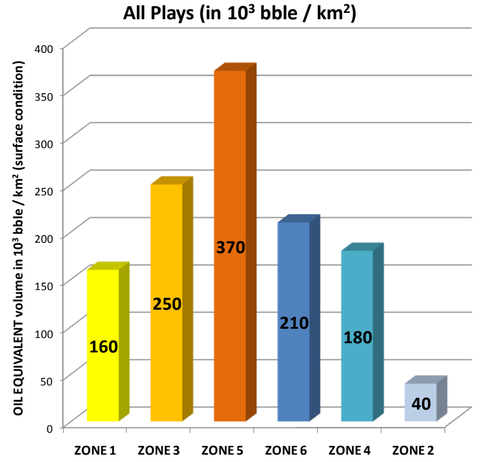
OIL EQUIVALENT



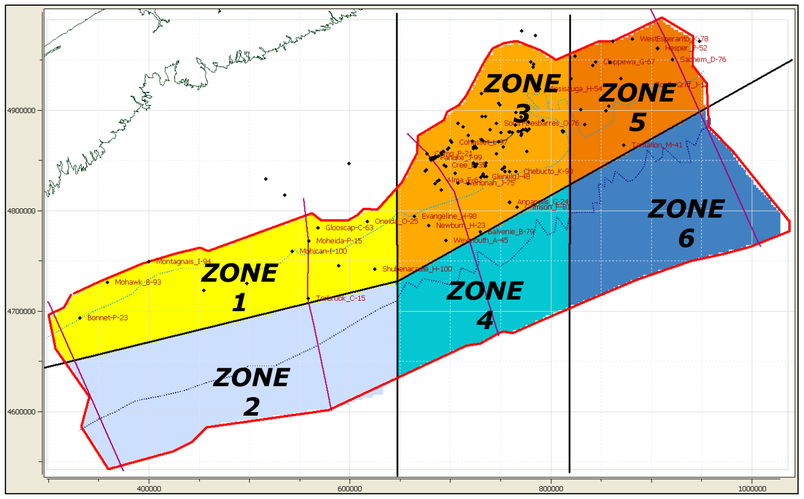
PER AREA







By ZONE	GRAND TOTAL (Volume)			VOLUME PER UNIT SURFACE (volume / km2)		
	TOTAL GAS volume in surface (Tcf) IN PLACE UNRISKED	*TOTAL OIL volume in surface (Mbbl) IN PLACE UNRISKED*	*TOTAL OIL EQUIVALENT volume in surface (Mbble) IN PLACE UNRISKED*	*TOTAL GAS volume in surface per AREA (Gcf / km²) IN PLACE UNRISKED*	*TOTAL OIL volume in surface (10³bbl / km²) IN PLACE UNRISKED*	*TOTAL OIL EQUIVALENT volume (10³bble / km²) IN PLACE UNRISKED*
ZONE 1	14	2470	**4400**	**0.5**	**92**	**160**
ZONE 3	35	1130	**6300**	**1.4**	**46**	**250**
ZONE 5	27	1650	**5500**	**1.8**	**112**	**370**
ZONE 6	26	1090	**5000**	**1.1**	**45**	**210**
ZONE 4	16	990	**3300**	**0.9**	**54**	**180**
ZONE 2	4.2	820	**1400**	**0.1**	**25**	**40**
Whole Basin	**121**	**8150**	**25900**	**0.9**	**57.4**	**180**



ZONE RANKING (Total Volume / Volume Per Area)

Assumptions

Volumes calculated by Temis® are **In Place** and **Unrisked**.
Main assumptions are:

- **5 potential source rocks** are considered.
  Aptian SR, Valanginian SR, Tithonian SR, Callovian SR, Pliensbachian SR.
  Source rocks distribution, richness, and thickness are uncertain, presence of organic-rich layers is not proven at the scale of the Basin (particularly the Pliensbachian SR).
- **5 active play systems** are considered.
  Aptian-Albian-Cenomanian (K112-K94), Hauterivian-Barremian (K130-K123), Berriasian-Valanginian-Hauterivian (J150-K130), Oxfordian-Tithonian (J63-J150), Early-Middle-Jurassic (J200-J163).
  Reservoir layers distribution, quality, and thickness are uncertain, particularly for Jurassic play systems, and in deep water zones.

Note 1: All closed structures (4 ways traps) are considered if the closure area exceeds 2 km², even subtle ones (in term of closure height and reservoir thickness). All reservoir layers, whether scattered in the play system or with low "net to gross", which may be considered non economic and/or insignificant in production tests, are accounted for in the calculation of unrisked volumes of oil and gas in place. In addition, volume calculation takes into account reservoir porosity whatever porosity, without discrimination by any sort of minimum porosity threshold above zero.

Note 2: There is no indication on the distribution of HC within each zone. This distribution may be heterogeneous, particularly in Zone 1, where trap charge is more likely east of the zone.

Zone 3 which contains the Sable Sub Basin is the richest in term of total hydrocarbon volume (oil equivalent) and in term of gas volume (1st rank). The global GOR is high in **Zone 3** and also in **Zone 6**, due to secondary cracking in deep reservoirs, very high maturity of deep source rocks, and the presence of gas-prone Cretaceous source rocks.

The largest amount of oil would be found in **Zone 1**. In that zone the main contributor is the oil-prone Pliensbachian SR. **Zone 1** partly drains **zones 2** and **4**, and Jurassic source rocks are immature to mature (oil window) only. Considering drainage area maps and maturity maps, the easternmost part of **Zone 1** seems more attractive.

If volumes are divided by surfaces of each zone ("volume per area" or "volume per unit surface"), **Zone 5** is ranked 1st for both oil and gas volumes. **Zone 5** would contain the highest density of hydrocarbon accumulations. **Zone 3** is in 2nd position for total hydrocarbon volume.

Zone 2 appears the least prospective zone both for oil and gas in total volume and volume per area. This is due to the fact that small drainage areas in salt mini-basins limits concentration of hydrocarbons.