Geological context and parcel prospectivity for Call for Bids NS13-1; seismic Interpretation, source rocks and maturation, exploration history and potential play types of the central and eastern Scotian Shelf.

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1. Introduction and scope

The six Parcels included within the NS13-1 Call for Bids are distributed across the north-central and eastern Scotian Shelf as illustrated in Figure 1.1. The Parcels are located predominantly in water depths of less than 100 m except on the Misaine Bank where Pleistocene tunnel valley depths can approach 200 m along the northern portions of Parcels 2 to 5. The Parcels cover an area where Late Jurassic Mic Mac and Early Cretaceous Missisauga formations have excellent reservoir potential in thick fluvial and shallow marine sand successions. Salt movement across all six Parcels provides a mechanism for a variety of trap types.

As explained in the Source Rocks and Maturation section, basin modelling has placed the Tithonian source rock within the present day oil window in the Huron Subbasin, and along the northwestern margin of the Sable Subbasin. There is also good evidence to suggest that Early Jurassic source rocks are within the present day oil window in the Abenaki Subbasin.

Parcel 1 includes the undeveloped Penobscot oil discovery which contains 65 MMBbls of mean oil in place. There are also two undrilled structures directly adjacent to the Penobscot discovery with additional oil potential of 82 MMBbls (mean). Parcel 1is also bordered by seven Significant Discoveries within the Sable Subbasin. Parcel 3 is within the Abenaki Subbasin and includes the Mic Mac J-77 and Mic Mac D-89 wells which encountered oil bearing sands. Parcel 4 has an untested, Early and Late Jurassic, stacked carbonate reef buildup.

Parcels 5 and 6 are within the Huron Subbasin. In addition to rollover anticline traps, these Parcels have a potential subsalt play near the South Griffin Ridge and good prospectivity within the interbedded clastic and carbonate system as confirmed with gas tests at Louisbourg J-47.

2. Eastern Scotian Shelf Regional Interpretation

A regional grid consisting of twelve 2D seismic surveys has been interpreted over the NS13-1 Call for Bids area. The varying data density across these surveys requires a gridding interval of at least 700 m by 700 m in order to create continuous time-structure maps. No 3D seismic programs have been collected in this region. For detailed maps and information on the distribution and vintage of the seismic programs see the **Data tab** of **CFB NS13-1 website.**

The Scotian Basin stratigraphic column is shown in **Figure 2.1**. The CNSOPB has adopted the seismic horizon nomenclature proposed in the Play Fairway Analysis. A diagram combining well penetrations within the parcels, geologic time scale, lithostratigraphy and interpreted seismic horizons is shown in **Figure 2.2**. Numerous wells reached the Jurassic section in the NS13-1 Call for Bids area. The density of well control and the deep penetration depths here allow seismic horizons to be correlated with relatively high confidence down to the Middle Jurassic strata across most of the six parcels.

The following time-structure maps were created from the seismic interpretation (maps are listed from deepest to shallowest):

Figure 2.3 J200 Synrift to early postrift

Figure 2.4 Autochthonous salt distribution (Argo Fm.) and basin structure

Figure 2.5 J163 Middle Jurassic – Top of Scatarie Mb.

Figure 2.6 J150 Top Jurassic (approx. top Abenaki / Mic Mac Fms.)

Figure 2.7 K130 Early Cretaceous - O Marker (approx. base of upper Missisauga Fm.)

Figure 2.8 K125 Early Cretaceous - Top of upper Missisauga Fm.

Figure 2.9   K113   Early Cretaceous - Top of Naskapi Mb. (Logan Canyon Fm.)

Figure 2.10   K94   Late Cretaceous - Top of Petrel Mb.

Figure 2.11   K78   Late Cretaceous - Top of Wyandot Fm.

Using these surfaces, the following isochron maps were generated (all maps are in two-way travel-time):

Figure 2.12   J163 - J200   Mohican and Iroquois Fms. Isochron

Figure 2.13   J150 - J163   Mic Mac Fm./Baccaro Mb. Isochron

Figure 2.14   J150 - J200   Jurassic Isochron

Figure 2.15   J130 - K150   Lower Missisauga Fm. Isochron

Figure 2.16   K125 - K130   Upper Missisauga Fm. Isochron

Figure 2.17   K125 - J150   Missisauga Fm. Isochron

Figure 2.18   K113 - K125   Naskapi Mb. Isochron

Figure 2.19   K94 - K113   Logan and Dawson Canyon Fms. Isochron

Rifting of the Scotian Margin began in the Middle Triassic and continued into the Early Jurassic forming a widespread region of horsts and grabens throughout the central and northeast Scotian Margin. A time-structure map of a time-transgressive seismic horizon interpreted to be late synrift to early postrift in age (~J200) defines the basement structure beneath the parcels **(Figure 2.3). Figure 2.4** summarizes the most important basement features, which were used to refine the boundaries of known (e.g. Sable, Abenaki) and newly named (e.g. Huron) subbasins relative to Late Triassic to Middle Jurassic depocenters.

The Abenaki Subbasin is a slightly arcuate and elongate depocentre whose NE-SW axis plunges to the east and widens towards the northern half of the Huron Subbasin (**Figure 2.4**). It is flanked to the north

by the LaHave Platform and a series of faults on the basin hinge zone herein termed the Erie Graben Complex (EGC) and is bisected by the Mic Mac Ridge. The southern boundary to the Abenaki Subbasin is the Missisauga Ridge. The term Missisauga Ridge was originally defined by Jansa and Wade (1975) and used to describe a deep, elongate salt pillow ridge associated with the basin-bounding North Sable High (Wade & MacLean 1990). In recent years Missisauga Ridge has been used variably to describe both the salt pillow and the North Sable High. Recent mapping for this Call for Bids package suggests the only the very eastern end of this "ridge", near the Chippewa L-75 well, is a salt pillow and that the underlying North Sable High is the prominent basin bounding structure. Within this study the term Missisauga Ridge is preferred over North Sable High when describing the basin bounding structural feature (**Figure 2.4)**.

The Huron Subbasin is a recent subdivision for the eastern extension of the Sable and Abenaki subbasins beneath the Banquereau Bank (OETR, 2011). It merges with the Laurentian Subbasin to the east, and is bounded to the south by the South Griffin Ridge. The Sable Subbasin is south of the Missisauga Ridge and has an eastern extent that extends to the northeast between the Missisauga Ridge and the South Griffin Ridge (**Figure 2.4)**.

Autochthonous salt deposition on the Scotian Margin is interpreted to be late synrift and was bounded by basement highs in most regions. **Figure 2.4** also shows the interpreted extent of autochthonous salt deposition (green polygon) and the major bounding horst blocks for the Argo Formation evaporites. Basement highs were influential in focusing the early expulsion of allochthonous salt bodies (Shimeld, 2004; Kendell, 2012). Sediment loading and downbuilding by Early Jurassic fluvial systems loaded the salt which was commonly pinned or buttressed in the basinward direction by basement highs (i.e. the Mic Mac, Missisauga and South Griffin ridges). Salt contact with these basement horsts forced the salt to climb vertically through the sedimentary section eventually forming either solitary salt diapirs or canopies. Diapirs are present in this area and noted on the structure maps at the eastern end of the Missisauga Ridge in the Huron Subbasin and off the southwestern end of the Mic Mac Ridge within the Abenaki Subbasin.

A post-rift thickness map for the Abenaki, Huron and Sable subbasins in the Play Fairway Atlas illustrates there is up to 13 km of basin-fill in Parcels 3, 4, 5 and 6 and up to 10 km of fill in Parcels 1,2 and 3 (Plate 6-1-1a, OETR, 2011). The Early Jurassic Iroquois and Mohican formations are the initial post-rift succession in the Scotian Basin; consisting of strandplain to shallow marine carbonates (Iroquois) and coeval fluvial-dominated texturally immature siltstones, fine grained sandstones and red-brown and green shales (Mohican) (Given, 1977). **Figure 2.5** is a time-structure map on the Scatarie seismic horizon (J163). This map is indicative of the structuring at the Mohican and Iroquois level throughout this region. There are a series of growths faults related to salt-withdrawal minibasins in Parcels 2 and 3 and throughout Parcels 2-6 the structure resembles that of the underlying basement. The influence of the southwest-northeast trending Missisauga Ridge is obvious in the south-central portions of Parcels 2-4 **(Figure 2.5).** The axis of the adjacent Huron Subbasin basin is also quite evident on the J163 structure map and trends southwest-northeast near the Tuscarora, West Esperanto and Esperanto wells. A time-thickness map from the J163 to the J200 illustrates the thickness trends of the early fill between basement highs **(Figure 2.12).** The distribution of grabens, half-grabens, and horst blocks, shown in figures 2.3 and 2.4, helped focus deposition during the Early Jurassic, with accommodation provided by basement extension and salt expulsion. Thick deposits of Iroquois and Mohican strata fill the deep grabens in the Abenaki and Huron subbasins. Some thickening of this sequence is also noted in the Erie Graben Complex in the northern part of Parcels 2 and 3.

Following the deposition of the Iroquois-Mohican succession in the Middle and Late Jurassic, sedimentation was dominated by fluvial-deltaic siliciclastics of the Mic Mac Formation and coeval shallow marine to reefal carbonates of the Abenaki Formation (Wade and Maclean, 1990). **Figure 2.13** is a time-thickness map of the mid/late Jurassic section (J150 to J163, representative of the thickness of both the Mic Mac and Abenaki formations. An obvious thick trends from southwest to northeast through the central and southern portion of the parcels and parallels the South Griffin Ridge. In general, this Middle to Late Jurassic section increases in carbonate content from north to south and some of this expanded thickness can be attributed to carbonate reef and ramp development of the Abenaki Formation. For example, Mic Mac clastics are present in the Mic Mac J-77, Mic Mac D-89, Peskowesk A-99, Tuscarora D-61, West Esperanto B-78 and Esperanto K-78 wells and have good porosities (e.g. ~19-22% at Esperanto K-78 and up to 22% at West Esperanto B-78). Moving to the south towards the South Griffin Ridge, wells penetrating this interval show that the carbonate content increases **(Figure 5.6)**. At Louisbourg J-47 the Mic Mac Formation is carbonate-rich with many tight, thick limestones. The thin Mic Mac sands that are present here also tend to have lower porosities than in the wells in the northern part of the parcels. However, the Mic Mac is still a potential reservoir interval in this area. An overpressured, 12.5 m Mic Mac gas sand at Louisbourg J-47 was tested at an estimated rate of 5.0 MMscf/d. Mechanical difficulties during the test prevented the well from flowing at higher rates. It was estimated, that had the test been successful the sand had the potential to flow at rates of up to 28 MMscf/d. Thick deposits of this J150-J163 sequence are also present surrounding the salt diapirs in Parcel 2.

The Missisauga Formation was deposited throughout the Early Cretaceous. This sand rich sequence of fluvial-deltaics to shallow marine sediments can be divided into upper and lower members that are separated by the O Marker, an interval of generally thin Hauterivian/Barremian oolitic limestones, **(Figure 5.6)**. A time-structure map on this horizon (K130) is representative of the structuring throughout this region at multiple horizons **(Figure 2.7)**. Listric faults are common along the basin hinge zone that trends southwest-northeast through the central and/northern parts of the parcels. This trend of faults related to the underlying basin hinge zone formed the rollover anticlines drilled at Mic Mac J-77, Tuscarora D-61, West Esperanto B-78 and Esperanto K-78. Structural lows are present north of the Missisauga Ridge and strata throughout the Late Jurassic and Cretaceous are folded across this basement horst block **(Figures 2.5-2.11)**. Another series of faults is present in the southern parts of the parcels. These faults offset strata down to the top of the South Griffin Ridge and often detach in salt expelled from the Huron Subbasin that veneers this ridge in several locations. These two fault trends are visible on most structure maps and are likely a result of two different processes: 1) differential compaction and folding across the underlying horst and grabens and 2) detachments into both autochthonous and allochthonous salt bodies.

Figures 2.15 and 2.16 are isochrons of the lower (K130 to J150) and upper Missisauga (K125 to K130) members respectively. There is a southwesterly shift of the deltaic deposits relative to the previous Jurassic isochrons. The southern portions of Parcels 1-5 have thick Cretaceous deposits and these thicken further south of the call parcels into the Sable Subbasin. The Missisauga has excellent reservoir properties and two thin oil zones were encountered in thick upper Missisauga sands in the Mic Mac J-77 well **(Figure 2.16).** One 62 m sand has 2.0 m of oil pay with net pay porosity of 32% and a deeper 41 m sand has 1.0 m of oil pay with net pay porosity of 34%. This is a very high net to gross interval and although the reservoir quality of these sands is very good to excellent, an adequately thick seal is required in order to produce a large oil column.

An Early Cretaceous potential regional seal within the Abenaki and Huron subbasins is the transgressive MFS Naskapi shale. A time-thickness map of the Naskapi shale (K113 to K125) is shown in **Figure 2.18.** Where sufficiently thick, the Naskapi can be an effective sealing horizon for the underlying upper

Missisauga Formation. This thickness is attained in the Sable Subbasin where the Naskapi is the seal for a number of upper Missisauga Significant Discoveries. The isochron in **Figure 2.18** illustrates that the Naskapi is relatively thin throughout the northern half of Parcels 2-6. Depending on fault throw and play type, it may not always be a reliable seal in this area. It's thickness increases across the listric growth faults in the southern half of blocks 1-6 where it may provide an adequate seal **(Figure 5.6)**. Although thin, the Naskapi shale is providing some seal at the Mic Mac J-77 well in Parcel 3, where thin oil columns were encountered.

A final isochron map of the K94 to K113 interval is representative of the time-thickness of the Late Cretaceous Dawson and Logan Canyon formations (**Figure 2.19).** The Logan Canyon comprises alternating shale and sandstone successions that are interpreted to have been deposited in a broad coastal plain and shallow shelf environment (Wade and Maclean 1990). This map shows a depositional thick trend across the central part of the parcels from southwest to northeast. The thickest parts of this interval are within Parcels 2, 3 and 4 and the interval thickens to the south towards the Sable Subbasin. These units are a potential reservoir interval and several thin oil zones were encountered in this sequence within Parcel 3 in the Mic Mac D-89 well. Here, three reservoir sands were encountered that ranged in thickness from 4-19 m. Each of these sands had between 1 to 3 m of oil pay and average net pay porosities of up to 30%.

3. Source Rocks and Maturation

Overview

Within the region covered by Call for Bids NS13-1, five source rock intervals have been identified and modelled (a sixth is speculative). They are grouped into major, minor or potential contributors of hydrocarbons depending on their geochemical and spatial attributes, depth of burial, maturation and other available data:

MAJOR

- Late Jurassic: Tithonian carbonate to deltaic transition MFS (Abenaki / Upper Mic Mac to Lower Missisauga formations) – OIL & GAS

- Early Jurassic: Pleinsbachian to Toarcian restricted to near-normal marine (Mohican and Iroquois Formation distal equivalents) – Dominantly OIL, Minor GAS

MINOR

- Early Cretaceous: Intra-Aptian deltaic MFS (Naskapi Member, Logan Canyon Formation) – Dominantly GAS, Minor OIL

- Early Cretaceous: Berriasian / Valanginian deltaic MFS (Lower Missisauga Formation) – Dominantly GAS

- Middle Jurassic: Callovian marine MFS (Misaine Member, Abenaki Formation) – Dominantly GAS, Minor OIL

POTENTIAL

- Late Triassic: Carnian-Norian lacustrine to restricted marine (Eurydice Formation and equivalents) – Dominantly GAS, Minor Oil

Temis™ petroleum systems modelling indicates that the Jurassic Tithonian and Pleinsbachian-Toarcian intervals are the best source rocks in the Call region ad are capable of generating significant quantities of oil and gas (OETR, 2011). Other intervals would be minor contributors due to their respective levels of maturity and distribution.

Although discoveries and production have been predomantly natural in the Scotian Basin, liquid petroleum has also been produced and differentiated into three to five families as detailed in the Hydrocarbons section, below.

Source Rocks

Research on the identification and characterization of Scotian Basin source rock intervals has been ongoing since the mid 1970s. Most of the published geochemical research was by researchers of the Geological Survey of Canada (e.g. J.P. Bujak, T.G. Powell, L.R. Snowden, D.R. Issler, M.G. Fowler, M. Obermajer and M.P. Avery) and others such as P.K. Mukhapadhyay (see separate References document for representative citations). Concurrently, the petroleum industry undertook similar studies and analyses, as well as others by consultants and academics, the results of which are available from the CNSOPB's Geoscience Research Centre / Data Management Centre.

The province of Nova Scotia's recent Play Fairway Analysis ("PFA"; OETR, 2011) compiled and updated historical research on petroleum source rocks, and in addition to undertaking new analyses incorporated these into new petroleum systems modelling for the basin. Within the area covered by this Call for Bids, the PFA reviewed existing data from selected wells and of these three were selected and studied in detailed to be used in Temis™ petroleum systems modelling. These three "Bible Wells" are all located in the Huron Subbasin (none in the Abenaki Subbasin): Dauntless D-35, South Griffin J-16 and Hesper P-52.

The cumulative result of this and all previous studies established the identities of the main source rock intervals, and characterised the properties of several families of oils. Four main intervals are known and later were characterised with regards to their properties.

They range from Middle Jurassic to early Cretaceous age and are marine shales of the Verrill Canyon Formation and its lateral MFS expression within the proximal fluvial-marine successions of the Mic Mac, Missisauga and Logan Canyon formations. Other source rock intervals identified in Early Cretaceous and younger strata have good TOCs (e.g. Logan Canyon Formation; 2-4%) but are shallow in the stratigraphic succession of the Call for Bids area and hence immature.

A fifth new marine source rock interval of Early Jurassic age is inferred from geochemical (seep and petroleum analysis) evidence and comparative studies that are described below (OETR, 2011). A speculative sixth source (Late Triassic-earliest Jurassic) is inferred from onshore successions but has no direct evidence to date.

1. Early Cretaceous – Intra Aptian deltaic MFS (Naskapi Member, Logan Canyon Formation)

Within the Call for Bids area, the Naskapi source rock interval is best described in the South Griffin J-16 well in the Huron Subbasin. It is the basal member of the Logan Canyon Formation and represents a major MFS interval following deltaic and shallow marine deposition of the Missisauga Formation (Wade and MacLean, 1990). The Naskapi's depositional environment is interpreted to range from tidal flat to marginal marine. It is a major regional shale-dominated sequence that thickens seaward with increasing

shale content, and proximal to the northern (marginal) part of the Scotian Basin it thins and becomes increasingly sand-dominated. Where it is thick enough, it acts as a regional seal, with a number of gas and oil shows and discoveries in overlying and underlying sandstones; e.g. Panuke (top of Upper Missisauga Fm.) and Cohasset (base Logan Canyon Fm. (Cree Member) oil fields.

The Naskapi has good source rock potential, with maximum TOC values slightly greater than 2%, and ranging between 1-2%. Within the South Griffin J-16 well, the hydrogen and oxygen indices (HI & OI) range between 50-75 and 60-160, respectively, indicating a Type III kerogen. In this well and the Dauntless D-35 well further to the east, the vitrinite reflectance (VR) is moderate (Ro=0.5-0.6) revealing incipient maturation only, hence in the Huron Subbasin it is mostly immature. The Naskapi is present in the Abenaki Subbasin though is thin and sand-dominated (>50%) and much shallower.

2. Early Cretaceous – Berriasian / Valanginian deltaic MFS (Lower Missisauga Formation)

The Berriasian / Valaginian source rock is not a discrete interval but is composed of a number of transgressive, MFS marine shales within the deltaic Missisauga Formation. Based on PFA "Bible" wells in the Huron Subbasin, and elsewhere in the Scotian Basin, the source rock shales have TOC values that range from 1-2%, averaging about 1%, with the organic matter dominated by Type III kerogens. Distally, the source rock improves in thickness and richness and has the potential to be a very good oil source (Barnard and Dodd, 1984). Data from the deepwater Annapolis G-24 and Crimson F-81 wells reveal a TOC range of 1.5-2.5% with the succession more deeply buried, such that the entire Missisauga Fm. is sufficiently organic-rich and mature to charge reservoirs. However, on the Scotian Shelf, the Berriasian / Valanginian interval is volumetrically small and thus is considered a minor source rock.

3. Late Jurassic – Tithonian carbonate to deltaic transition MFS (Abenaki / Upper Mic Mac to Lower Missisauga formations)

The Tithonian source rock interval is believed through previous research and modelling (Temis™) to be the most important oil and gas source rock in the Scotian Basin. It was deposited during the transition from carbonate (Abenaki Fm.) to deltaic (Mic Mac Fm.) sedimentation corresponding to the lower part of the Verrill Canyon Fm. MFS. The shale was deposited in a shallow, open marine shelf setting that appears to have been slightly anoxic. This source rock has been difficult to identify due to the use of lignosulfate in the drilling mud in well penetrations when approaching overpressure zone that usually corresponds with the top of the Jurassic. Kerogen microscopy appears to be the best way to define / identify this source rock, which is composed of Type IIA/IIB-III kerogen capable of generating gas, condensate and oil from a terrestrial to mixed terrestrial-marine source (Mukhopadhyay and Wade, 1990).

Within the Huron Subbasin, the average TOC in this interval as encountered in the Louisbourg J-47 and South Griffin J-16 wells is 2-3% with maximum values approaching 7%. The HI and OI indicate a Type IIB-III / Type III kerogen that is mostly gas-prone (Mukhopadhyay and Wade, 1990; OETR, 2011). Maturation in the Louisbourg well (average TOC=3%) is moderate (Ro=0.7%) and retains the potential to generate gas. In contrast, shales of the Tithonian MFS are deeper in the South Griffin well. While having a similar average TOC of 2% (1.25-1.64% range), the very low HI and low OI values and high maturation (Ro=1.6-1.81%) indicate a depleted source rock (Mukhopadhyay and Wade, 1990).

There is limited TOC and maturity data for this source rock the Abenaki Subbasin, though probably has significant upside potential. The section in the Mic Mac H-86 well showed that the TOC ranged between 2-4%, with a thermal maturity of Ro=0.6 indicating incipient maturity only or at the onset of the oil window. This well was drilled on a deep salt feature adjacent to an intra-basin. In depocentres on either

side of the Mic Mac Ridge, this source rock is deeper and more mature and so could be a major contributor to local accumulations of oil. Unfortunately, a 37.8° API oil recovered from a DST in the Mic Mac J-77 well was not available for analysis, so its relationship to this or other potential (deeper) Jurassic source rocks remains unknown.

There is evidence that a similar Late Jurassic - Early Cretaceous oil-prone source rock exists in the Baltimore Canyon Trough region (Sunde and Coffey, 2009). Geochemical biomarker analysis of remnant oils from an onshore well indicates they were sourced from a shale / marine marl deposited in a distal marine to slope depositional environment. The presence of oleanane indicates a Cretaceous age. Malinconico and Weems (2011) studied the geothermal gradient and maturity of a number of wells on the U.S. East Coast and concluded that the maturity of wells in the region was low (Ro=0.4-0.6%). As such, the Cretaceous succession could not have generated the observed oils. This suggests the low maturity indicates that the remnant oils were preserved in carrier beds and oil migration was a later phase. The probable distally-equivalent source rock would now be more deeply buried and currently within the oil window.

4. Middle Jurassic – Callovian marine MFS (Misaine Member, Abenaki Formation)

The Callovian MFS is represented in the Scotian Basin by the Misaine Member, and is the only siliciclastic succession within the thick, carbonate-dominated Abenaki Formation. The velocity contrast between the Misaine MFS shales and underlying Scatarie Member (J213) platformal limestones results in the creation of an excellent regional seismic marker (**Figure 5.8**). As such, the Misaine can be mapped throughout the Scotian Basin though is lost in the distal parts of the basin. It is present deep in the Sable and Huron subbasins though has been penetrated in wells drilled near and on the basin hingeline fault and on the LaHave Platform.

There is limited information available on the source rock potential of the Misaine in the NS13-1 Call parcels. In the Abenaki Subbasin, geochemical analysis in the Abenaki J-56 well revealed Type IIA-IIB and II-III oil- and gas-prone kerogens with a TOC of 2.0% (Mukhopadhyay and Wade, 1990). The HI and OI levels indicate that the Misaine is only partially depleted in its generative potential (HI=100) that is consistent with the level of maturity (Ro=0.8%) as applied to a Type II kerogen (OETR, 2011).

This source rock interval is significantly shallower in the Abenaki Subbasin than in the Huron, and probably not yet fully depleted. It is possible that the basement structural elements still had an influence upon sedimentation in the early Middle Jurassic to the extent that water circulation in the basin was inefficient and resulted in more restricted marine conditions and associated water stratification and anoxia. In this setting the potential exists to create and preserve oil-prone organic matter (Types I and II/IIA kerogens). This interval (or a deeper one) could be the source of the Mic Mac J-77 oil that migrated into higher reservoirs from proximal, adjacent depocentres up along late-phase (Tertiary) faults.

5. Early Jurassic – Pleinsbachian to Toarcian restricted to near-normal marine (Mohican and Iroquois Formation distal equivalents)

Though not yet penetrated by the drill bit, empirical evidence increasingly supports the presence of an oil-prone, Type II marine Pleinsbachian to Toarcian age regional source rock interval in the Scotian Basin.

The most recent compilation and assessment of source rocks in the Scotian basin is that of the OETR's 2011 Play Fairway Analysis (PFA). The PFA reviewed and consolidated extant data and interpretations with new data acquired from analyses of bottom seeps (GeoMark, 2001), as well as undertaking its own analyses. From these data and comparative study with known source rocks from other circum-Atlantic basins, a new, fifth regional source rock interval is inferred. The following section is more comprehensive than the preceding given the importance of this interval to the Call for Bids play area, and potentially the deep water region of the southwestern Scotian Slope. Unless otherwise indicated, the following is sourced from the PFA.

An important recent contribution to evaluating the Scotian basin's source rocks was a study by GeoMark (2001) and incorporated into the PFA. This study analysed piston core samples taken along the deepwater Scotian Slope, and compared the extracted hydrocarbons with those from the Scotian Basin (shallow water) and the Jeanne d' Arc Basin, Newfoundland (Hibernia Field). In addition to this correlation were interpreted their respective ages and depositional environments, and potential thermal maturation trends.

The analytical results revealed these oils were distinctive from the Jeanne d' Arc and Scotian Shelf oils. The low pristine/phytane versus C19/C23 ratio indicated they were similar to the Newfoundland oils with both sourced from a source dominated by Type II oil-prone kerogen. The Scotian Shelf oils indicated a Type III gas-prone kerogen source. However, analysis of saturate and aromatic hydrocarbon fractions for stable carbon isotope composition revealed that the seep oils were different from both regions. Comparison of terpane mass chromatograms against GeoMark's proprietary global oil data base suggests that the oils match those sourced from distal marine shales and/or calcareous shales / marls. All piston cores samples from the Scotia Basin showed low levels of gammacerane, a biomarker indicative of stratified water columns during the time of deposition (Sinninghe-Damste et al., 1995). The low level of gammacerane in these samples would infer deposition under less restricted, more normal marine conditions though with some water stratification. The oleanane biomarker (a product from angiosperm remains) was absent, confirming the source was older than Late Cretaceous.

OETR (2011) compared these analyses with its own for oils, condensates and source rock extracts from selected Scotian Basin wells and similar biomarker data from other sources. A condensate sample from the Venture B-13 well from the shallow water Venture gas field (DST #6, 4572-4579 m, base Early Cretaceous Missisauga Fm.) revealed the presence of gammacerance which was confirmed to have come from an indigenous source and not a contaminate. Traces of gammacerane were also found in fluid inclusions from the Late Triassic-Early Jurassic Argo Formation salts in the deep water Weymouth A-25 well, and the homohopane ratio C35/C34=1 suggesting a carbonate depositional environment for the source.

OETR (2011) then compared the analyses with data from Early Jurassic (Pleinsbachian-Toarcian), oil-prone source rock successions from conjugate eastern Atlantic margin basins such as the Portuguese Lusitanian and Peniche basins, and the Essaouira and Tarfaya basins of Morocco. The Portuguese source rock successions are composed of marine black shales, marls and carbonates deposited on a carbonate ramp setting. They contain Type II kerogens and tend to have high gammacerane levels and very high TOCs. Duarte et al. (2010, 2012) analysed the latest Sinemurian to earliest Pleinsbachian Água de Madeiros Formation in the Lusitanian Basin. Though the succession is immature onshore (Ro<0.45), it is an excellent potential source rock offshore with its organic-rich (Type II kerogen) shales, marls and limestones having maximum TOC ranges of 15-22%. Additional geochemical data on these source rocks' geochemical properties and distribution in these basins is presented in Silva et al. (2011, 2012). In the

Peniche Basin, Pleinsbachian age Type II source rocks have a similar TOC maximum range of 14-20% (avg. 3.8%) (Veiga de Oliveira *et al.,* 2006 as referenced in OETR, 2011).

From the Moroccan offshore margin, analysis of extracts from Toarcian age source rocks from the DSDP Leg 79, Site 457 (Hinz *et al.,* 1982; Rullkötter *et al.,* 1984) differ from those in the Portuguese basins. While deposited in a similar deposition setting, the oils reveal no to low (background) levels of gammacerane. The shale / carbonate succession was similar but did not exhibit any characteristics of hypersalinity or stratified water conditions. Further to the south, biomarker analyses of oils from the Sidi Rhalem Field (onshore Essaouira Basin) and offshore Cap Juby Field (offshore Tarfaya Basin) were made available to OETR from GeoMark. They revealed in both the low levels of gammacerane, and C35/C34 ratios being less than one also inferring a carbonate dominated source. There is a good match of the isotopic signatures with the Nova Scotia piston core oil samples, suggesting a similar age source and depositional environment. Though the source interval(s) is uncertain, Morabet *et al.* (1998) suggest that for these regions it is carbonate-dominated Type II source and ranges from Lower Jurassic (presumed Pleinsbachian to Toarcian) to Oxfordian in age.

A recent paper by Sachse *et al.* (2012) studied the organic geochemistry and source rock potential of a Pleinsbachian to earliest Toarcian succession of limestones and marls further to the east in the central portion of the Middle Atlas Rift. The kerogens were determined to be Type II or transitional Type I/II with TOCs ranging from 1.1 to 3.9%. Analysis of a representative sample (Tab. 5 & Fig.8B) reveals little to no gammacerane. The succession is interpreted to have been deposited in marine depositional environment with a stratified water column with bottom waters that were oxygen-depleted but not anoxic.

New evidence for a Scotian Basin Early Jurassic source rock comes from the analysis by Sassen and Post (2007) of a condensate sample from the Deep Panuke gas field (Late Jurassic Abenaki Formation, M-79A well). Detailed analysis of the sample included GC-MS for common biomarkers and diamondoids, and GC-IRMS for carbon isotopic properties of saturate and aromatic fractions. The GC-MS revealed pristine and phytane with very low peaks in relation to adjacent *n*-alkanes indicating the condensate underwent advanced thermal cracking during deep burial prior to migration in the leached and dolomitized reef margin reservoir. The thermal maturity index was defined as TAI=0.95 that approximates a Ro=1.4, and diamondoid levels in the condensate were very high (~1%) indicative of high thermal cracking of the original oil. While common biomarkers were lost from this petroleum, traces of key ones are present, the most important (for this review) being gammacerane. With the low pristine/phytane ratio (1.23), this supports the interpretation of a hydrocarbon from a Type II marine source. In comparison, the average pristine/phytane ratio for the piston core samples was also low at 1.43 (n=12; 1.23 to 1.56) (GeoMark, 2001). Sassen and Post (2007) suggest that the source lithologies were a calcareous shale or carbonate, which reflects the same interpretation by the GeoMark study.

It is possible that a second, slightly older Early Jurassic source could exist. It would have been deposited immediately post-salt and prior to the pre-Breakup Unconformity during the Hettangian to earliest Sinemurian representing a transitional evaporate to siliciclastic succession (Argo Formation to Heracles unit). The proposed Pleinsbachian to Toarcian source interval was deposited post-BU and the distal (seaward) equivalent to the Mohican (clastic) / Iroquois (carbonate) succession. During the development of the margin in the Late Triassic to Early Jurassic, the depositional setting changed from a subsea level rift basin to a narrow and shallow intra-rift seaway. Hydrographic conditions would likewise reflect this change, and in this near equatorial location evolve from hypersaline to near hypersaline / normal marine conditions that would contribute to water stratification. While gammacerane is low to absent in the Moroccan oils, this cannot be used alone as a diagnostic feature of a Toarcian age source rock,

though this might be a clue to infer these oils are post-BU with marine waters approaching normal salinities. The low gammacerane levels in the Nova Scotia oils may also suggest mixing / diluting of pre- and post-BU oils. The respective source rocks would be separated by an unconformity and could possibly overly each other and thus have the same maturation profile with mixing of produced hydrocarbons during concurrent migration. This two source rock scenario remains speculative.

6. Late Triassic – Carnian-Norian lacustrine to restricted marine (Eurydice Formation and equivalents)

A sixth potential source rock interval may exist though there is no direct evidence for its presence offshore. Onshore eastern North America, Late Triassic to Early Jurassic fluvial-lacustrine-playa successions are found in synrift, half graben basins of the Newark Supergroup (Olsen, 1997). Some of these basins have identified source rocks, and a few oil shows are known. In the shallow parts of the Scotian Basin (i.e. LaHave Platform), similar basins are present but devoid of organic material. However, outboard of the basin's hingeline half graben architectures are observed on seismic and they are inferred to exist beneath the Argo Formation salts in deeper parts of the basin. Kettanah (2011) identified liquid and vaporous hydrocarbons in fluid inclusions within salts of the Late Triassic-Early Jurassic Argo Formation from the Glooscap C-63 and Weymouth A-45 wells. The characteristics of the liquids were determined to be characteristic of "complex, high molecular weight, aromatic or cyclic hydrocarbon compounds higher than methane". The author commented that given their stratigraphic position, the potential source could have been the underlying sediments of the Norian-Rhaetian Eurydice Formation.

Later analysis of the fluid inclusions revealed that gammacerane biomarker was absent in the authochthonous salts in the former well, but present in the allochthonous salts of the latter (see Pl.4-3-6, OETR, 2011). The profile was considered very similar to one for a condensate sample from the Deep Panuke gas field. The PP3C well condensate sample had a very similar homophone C34-C35 ratio (~1.0) inferring a carbonate depositional environment for the source facies (Fowler and Obermajer, 1999). This sample was obtained from the Late Jurassic Abenaki Formation carbonate reservoir that was probably from an older, deeper and more mature source interval as indicated by Sassen and Post (2007). The arid, redbed depositional environment represented by the Eurydice sediments is based on limited penetrations along the basin margin, though the succession could be different and more favourable for source rock deposition in the deeper parts of the rift basin.

Maturation

As part of the Play Fairway Analysis (OETR, 2011) 1D, 2D and 3D basin modelling was performed utilizing the Temis™ software that incorporated data on petroleum system elements and processes. From all available data, Common Risk Segment (CRS) maps were created to illustrate the presence, maturity and migration of source rock intervals (. CRS maps for reservoir and seal were also created for all intervals. Composite CRS maps were generated for five designated petroleum systems for the Scotian Basin. Burial history and maturation were modelled deriving information from published and newly acquired datasets.

For selected wells, temperature, maturation and pressure data were derived to generate well and composite regional burial curves for temperature, maturation (vitrinite reflectance, Ro) and pressure. Maturation history and potential expelled hydrocarbons were calculated utilizing input parameters for each source rock interval (age, TOC, kerogen type, initial hydrogen index, thickness) (OETR, 2011; Plate 7-3-1-3a). Incorporating these data and results into the Temis™ 3D modelling were generated the transformation ratio (TR) for through time for selected source rock and play intervals for the entire

Scotian Basin (TR = observed versus initial hydrogen index; differs for kerogen type) (OETR, 2011, Plate 7-3-1-3b).

Within the Call for Bids region, five wells were used for calibration in the 3D petroleum systems modelling (Note: 31 wells were used for the entire Scotian Basin):

Abenaki Subbasin:

- Chippewa G-67
- Missisauga H-54

Huron Subbasin:

- Sachem D-76
- West Esperanto K-78 *
- South Griffin J-13 *

Other data related to determining the source rock intervals' properties and maturation were sourced from the following wells:

Newly Acquired TOC & Rock Eval Data (OETR, 2011)

1. Chippewa L-75
2. Erie D-26
3. Iroquois J-17

Existing TOC & Rock Eval Data (Geological Survey of Canada's "BASIN" online database):

1. Abenaki J-56
2. Dauntless D-35 *
3. Iroquois J-17
4. Louisbourg J-47
5. Peskowesk A-99
6. South Griffin J-13 *
7. West Esperanto B-78 (CNSOPB Database) *

Existing Maturation Data (Geological Survey of Canada's "BASIN" online database):

1. Abenaki J-56
2. Chippewa L-75
3. Dauntless D-35 *
4. Hesper I-52
5. Iroquois J-17
6. Louisbourg J-47
7. Mic Mac H-86
8. Mic Mac J-77
9. Missisauga H-54
10. Sachem D-76
11. South Griffin J-13 *
12. West Esperanto B-78 *
13. Wyandot E-53

Note: Asterisk (*) indicates a PFA "Bible" well.

The following section reviews the characteristics of the five known, and one speculative / potential, source rock intervals with emphasis on the Jurassic Tithonian and Pleinsbachian-Toarcian intervals. It should be noted that extrapolation of the Temis™ modelling results into the outer margins of the basins

was required, with the hingeline zone in the northern parts of Parcels 2-6 having little to no results generated / presented (OETR, 2011).

MAJOR Source Rock Intervals

Late Jurassic: Tithonian carbonate to deltaic transition MFS (Abenaki / Upper Mic Mac to Lower Missisauga formations) – Dominantly OIL & GAS

Modelling of this source interval in the PFA (OERA, 2011) revealed that this source interval should be considered as a significant contributor to the Scotian Basin's hydrocarbon endowment. As described above, it represents deposition in a transitional setting from a carbonate-dominated marine (Abenaki) to siliciclastic fluvial-deltaic environment. The source interval lithologies have an average TOC of about 3% composed of mixed Type IIA/IIB-III kerogens capable of generating gas, condensate and oil (Mukhopadhyay and Wade, 1990). The deposition of this source is regional in scope centred in the central and eastern parts of the Scotian Basin. The interval's transformation ratio progressively increases from the hingeline basinward up to a maximum of about TR=60% in the depositional lows behind the South Griffin Ridge in the Huron Subbasin, and isolated ones inboard of the Abenaki's Missisauga Ridge. None of this source interval is overmature in the Call region (**Figure 3.1**).

Early Jurassic: Pleinsbachian to Toarcian restricted to near-normal marine (Mohican and Iroquois Formation distal equivalents) – Dominantly OIL

As discussed previously, this proposed source rock is based on the analysis of oils recovered from several well tests and piston cores; it has yet to be encountered in a well. Petroleum systems modelling (Temis™) suggests that this source interval is the only one that reaches maturity in the southwest platform, margin and slope of the Scotian Basin (OETR, 2011). In the southeastern part of the Call region (Parcels 34-6), modelling indicates that there was near complete expulsion of hydrocarbons (TR=90-100%, oil, minor gas). However, most of the Abenaki Subbasin (Parcels 2-4) and northern third of the Huron Subbasin are not included in the modelling (**Figure 3.2**). Nevertheless, it is theorized here that this region could be the location for the development of a significant source rock that is still mature.

The presence of shallow underlying and adjacent basement structural elements during the Early Jurassic would have exerted an influence on the seafloor morphology and water circulation. In this setting, there would be good potential to generate anoxia in local depocentres in which sediments with high TOC, oil-prone would be deposited. Oils generated from this source rock would have migrated into an adjacent / overlying reservoirs and preserved there over time with a very effective overlying seal. A second phase of migration could have occurred much later in time due to fault breaching of the seal. For the Mic Mac J-77 oil discovery, Tertiary age faults above a deep salt are the likely migration pathways. They may have been created in response to shaking of the Scotian Margin shallow basement by the 50.5 Ma Montagnais impact event to the southwest.

This deep source / reservoir scenario may also be reflected in the thermally overmature oils identified in the Late Jurassic Abenaki Formation fractured, leached and dolomitized carbonates of the Deep Panuke field (Sassen and Post, 2007). This high thermal maturity supports the idea that these oils were undisturbed for a long period of time prior to late phase migration. Unfortunately, there are no analyses of the Mic Mac J-77 oil to confirm its source and maturation level. If this scenario is valid, then the modelled high- to over-maturation of this potential source rock underestimates its potential.

MINOR Source Rock Intervals

Early Cretaceous: Intra-Aptian deltaic MFS (Naskapi Member, Logan Canyon Formation) – <u>Dominantly GAS, Minor OIL</u>

In the Abenaki and northern half of the Huron subbasins, the Naskapi is thin and dominated by coarser grain siliciclastics. It is present high in the stratigraphic section and thus is immature. It becomes thicker in the southern half of the Huron Subbasin and easternmost extension of the Sable Subbasin inboard of the South Griffin Ridge. Here its deeper burial depth increases its maturity with a transformation ratio up to 40% though with limited generation of hydrocarbons (mostly gas). It is not interpreted to have any hydrocarbon contributions in the Call for Bids region.

Early Cretaceous: Berriasian / Valanginian deltaic MFS (Lower Missisauga Formation) – <u>Dominantly GAS</u>

In the Abenaki Subbasin this source rock interval, and indeed the entire Missisauga Formation, is sand-dominated with little shale present. It is shallow and thus immature with no hydrocarbons (gas) generated. This source interval is better developed in the southern part of the Huron Subbasin and eastern sable Subbasin (Parcels 4-6) inboard of the sag behind the South Griffin Ridge, though the Missisauga Formation sand/shale ratio is high and source intervals are thin. Nevertheless, some hydrocarbon expulsion is predicted by modelling, with gas dominating.

Middle Jurassic: Callovian marine MFS (Misaine Member, Abenaki Formation) – <u>Dominantly GAS, Minor OIL</u>

As described previously, the Misaine Member is widespread across the Call region and Scotian Basin. This source rock has incomplete (40-80%) expulsion of hydrocarbons (gas, minor oil), being immature along the basin hingeline margin and mature elsewhere except for the southern half of the Huron and Abenaki subbasins where it is overmature; TR=80-100% (Parcels 3-6) (**Figure 3.3**). However, it is acknowledged that due to limited data an accurate estimate of the Misaine's potential is uncertain (OETR, 2011). This has significant implications regarding its modelled generative potential, thus it has an undetermined upside potential. It is this region that may have to most potential Misaine source rock upside. Like the potential early Jurassic source interval, the presence of underlying basement structural elements during the time of its deposition could have exerted an influence on its formation though to a lesser degree. Gas generated from this source interval might be that encountered and tested in the lower part of the Mic Mac Formation in the Louisbourg J-47 well.

<u>POTENTIAL Source Rock Interval</u>

Late Triassic: Carnian-Norian lacustrine to restricted marine (Eurydice Formation and equivalents) – <u>Dominantly GAS, Minor OIL</u>

For most of the Call region, potential source rocks from this interval would be deeply buried beneath the Argo Formation evaporites and invariably overmature. Their maturity would be lower adjacent to the border fault zone, and in the small half grabens along its crest (Eire Graben Complex) where pre-BU strata are present. Short distance migration from either source location could be evidenced by the oil staining and minor oil pay identified in the shallow Eire D-26 and Wyandot E-53 wells.

Hydrocarbons

The Scotian Basin is primarily gas-prone based on the great volume of source rock successions that had significant input from deltaic depositional systems. Most discoveries and production were of gas with

associated condensates, yet there are a number of significant oil shows and discoveries, and previous oil production.

Since the late 1970s, researchers have undertaken analyses of these liquids in order to classify them and derive information related information on maturation and source rock relationships. Powell and Snowdon (1979) defined three oil and condensate families source predominantly by terrestrially dominated deltaic and marine shales of the Mic Mac, Missisauga and Verrill Canyon formations. In the 1990s, P.K. Mukhopadhyay undertook a comprehensive study of Scotian Basin hydrocarbon and source rock characterizations and relationships in association with the Geological Survey of Canada with a number of important papers and research contributions published. Mukhopadhyay *et al.* (1995), using cluster analysis of polyaromatic compounds, defined two oil families. Group I is comprised of high maturity condensates and associated gas derived from a terrestrial source (Type IIB/III kerogens). Group II oils from the Cohasset-Panuke-Balmoral fields suggest a marine source generated from mixed organic matter types (Type IIA/III kerogens).

In a geochemical analysis of oils and condensates from the Sable Subbasin, Illich *et al.* (1999) defined five oil families (three larger groupings). Two Families, A and B, were determined to have been generated from terrestrial type (III) organic matter from two closely related sources. The third, Family C, may represent the products of oil mixing since they have geochemical compositions indicative of terrestrial (Type III prodeltaic) and marine (Type II, carbonate-rich) source rocks. The remaining oils were grouped into two catch-all families, D and E. These contain very mature oils, some with unique compositions, and others that might be contaminated with drilling additives. They all have slightly different maturities that could represent separate source intervals. A Family D oil from the Venture D-23 well (4889m, DST No.4, 6U sand, Missisauga Fm.*) contained an above background level of gammacerane though the source rock and its age is unknown, but could be from an older, Early Jurassic source. (* Note: Illich *et al.* (1999) do not indicate the formation and DST number, and the 4771 m sample depth is incorrect.)

Fowler and Obermajer (2001) defined three families of liquid hydrocarbons (1, 2 and 3a & 3b) in the Scotian Basin. Each has characteristic properties, maturation profiles and geographic separation suggesting they came from separate source rocks, with most sourced from terrestrially-derived organic matter (Type II-III). The high gravity (47-55 API) oils from the Cohasset, Panuke, Balmoral and Penobscot fields are from Family 1 and are probably the least mature. Family 2 oils are found in the Arcadia, Banquereau, Glenelg and North Triumph shelf-edge fields in the Sable Subbasin and were generated from rocks with greater levels of higher land plant material than the others, or, that they are less mature. Family 3 oils may be due to a mixture of the Family 1 and 2 oils. Since Family 1 oils are only found in the Cohasset area on the west side of the Sable Subbasin, and Family 2 in the North Triumph area in the south, this significant geographic separation supports the interpretation that they are from different sources. This study indicated that the Scotian basin oils and condensates had Ro equivalents of between 0.7 and 0.94% confirming they were generated in the central part of the oil window.

4. Exploration History

The Call for Bids NS13-1 area was one of the first regions to be explored on the Scotian Margin in the early 1970s, predominantly by Shell, and then by Mobil. Seismic, gravity and magnetic programs were ultimately followed by 20 wells, drilled up to 1976, targeting salt and basement related structures. These relatively shallow water plays were the first to be recognized and mapped on the margin. This early

exploration effort established that a working, oil prone hydrocarbon system existed, but commercial success remained elusive.

The second phase of exploration followed in the early 1980s with 11 more wells drilled by 1985 that mainly tested rollover anticline closures, similar to the successful gas plays being pursued in the Sable Subbasin at the time. This effort resulted in major gas shows at Louisbourg J-47 and SW Banquereau F-34, with Banquereau C-21 being declared a Significant Discovery.

The third exploration phase began in 2000 with four wells drilled in the northwest margin of the Sable Subbasin testing rollover structures. Of the 35 wells drilled in the region, only one significant discovery licence was awarded at Banquereau C-21, though several significant oil and gas shows were observed along with minor staining.

Table 4.1 lists details on all wells, sorted by parcel, including hydrocarbon shows, TD formations, play types, basin, operators, and spud dates. Table 4.2 sorts the table by spud date and Table 4.3 by Subbasin. A list of all of the available seismic data, well data, and interpretation reports is available in the Data section.

Gravity-driven and salt-related structural closures in the Abenaki and Huron subbasins incorporate strata of the Late Jurassic Mic Mac and Early Cretaceous Missisauga formations, with potential reservoirs being thick fluvial and shallow marine sand successions. They are generally medium to coarse grain with good to excellent porosity that decreases with depth. Effective seals may be an issue in the upper successions.

Parcel 1

The most recent exploration drilling has occurred in Parcel 1, with three wells drilled between 2000 and 2004. Both clastics and carbonate plays were targeted. Parcel 1 is bordered to the east by seven significant gas discoveries and to the south by Exploration Licence 2427 that was awarded to Shell in 2013. There are six exploration wells on this parcel, one delineation well and one sidetrack.

In the eastern part of the Abenaki Subbasin, a significant oil discovery (36° API) was made by Shell in the Penobscot L-30 well (1976). Approximately 12.2 m oil pay was identified in several Early Cretaceous Missisauga formation channel sandstones. Recent evaluation by the CNSOPB has an estimated mean original oil in-place of 65 MMBbls. There are also two undrilled structures directly adjacent to the Penobscot discovery (North and Northeast Penobscot) with additional mean oil in-place of 82 MMBbls. This discovery is described in more detail in Section 5.

The southern half of Parcel 1 covers the northwestern edge of the productive Sable Subbasin with 3 recent wells.

Approximately 13 km to the southeast from Penobscot L-30, Shell Canada Resources drilled the South Desbarres O-76 well in 69 m of water on a separate structure in 1984. This well reached a total depth of 6039 m and did not encounter any hydrocarbons.

The Emma N-03 well was drilled by Mobil in 2000. The upper part of the target zone was composed of a thick Early Cretaceous succession of Missisauga Formation fluvial and channel sands and thin intervening shales. The sands had very good porosity but were wet. A thick section of Late Jurassic Mic Mac Formation shoreface sands was encountered but exhibited poor porosity due to calcite cementation. Only two metres of questionable gas pay was found in a Mic Mac sandstone in the

increasingly shale-dominated lower portion of the drilled interval. The thin, poor quality sealing shale combined with a small, leaking crestal fault on the structure was determined to be responsible for the limited pay.

Marquis L-35 and L-35A (sidetrack) was drilled by Canadian Superior in 2002, using only 2D seismic data, to test the Jurassic carbonate bank, although porosity was encountered in the Bacarro, no hydrocarbons were found.

Mariner I-85 was drilled by Canadian Superior in 2003, using only 2D seismic data, to test for fault bounded Cretaceous and Jurassic clastics. The sand development at this location was poor and only minor net gas pay was present in a very fine to fine grained Mic Mac Formation sandstone.

Kegeshook G-67 (1985) was drilled into tight Abenaki platform carbonates above the Missisauga Ridge.

Parcel 2

There were four wells drilled on Parcel 2. Abenaki L-57, Iroquois J-17 and Abenaki J-56 were drilled in 1970 on very poorly imaged salt diapirs. Minor oil staining was found in Iroquois J-17 and gas charged mud was recovered in Abenaki J-56. Dover A-43 (1984) was drilled on a fault dependant closure with no shows.

Parcel 3

On Parcel 3, all six wells drilled by Shell in the 1970s show oil indications of varying significance. Four of the six wells (Mic Mac J-77, Missisauga H-54, Mic Mac H-96, Mic Mac D-89) were drilled into salt related structures and two (Wyandot E-53, Erie D-26) were drilled on basement highs.

The Mic Mac J-77 well was drilled in 1970 and encountered minor oil pay in two sands at the top of the Early Cretaceous Missisauga formation:

- Zone 1: 1984.0 – 2045.7 m (62 m sand: 2.0 m oil pay, 32% avg. net pay porosity)

- Zone 2: 2054.0 – 2095.0 m (41 m sand: 1.0 m oil pay, 34% avg. net pay porosity)

In addition to 7.6 litres of 38.7° API oil recovered from a wireline test of Zone 1 at 1985.5 m, additional oil staining was documented in sandstones of the Dawson Canyon, Logan Canyon and Missisauga formations. Beyond the original analysis of this oil's physical properties, its age, potential source and geochemical characteristics are unknown. The follow-up Mic Mac D-89 delineation well (1976) found 6.0 m net oil log pay in three stratigraphically higher sands at the top of the Late Cretaceous Dawson Canyon (Zones 1 & 2) and Logan Canyon formations (Zone 3):

- Zone 1 818.8 – 829.5m (~11 m sand: 2.0 m oil pay, 28% avg. net pay porosity)

- Zone 2: 871.5 – 875.5m (4 m sand: 1.0 m oil pay, 26% avg. net pay porosity)

- Zone 3: 899.0 – 918.0m (19 m sand: 3.0 m oil pay, 30% avg. net pay porosity)

Two early wells drilled by Shell in 1970 to test drape over basement structures both encountered thin oil pay. The Wyandot E-53 well penetrated porous reservoir sandstones in the Missisauga (very good to excellent porosity), Mic Mac (fair to very good), and Mohican formations (fair to good). It discovered a

single 3.0 m of net oil pay within a thin Mic Mac Formation sandstone over which two wireline tests were run (Formation Interval Tester – FIT – with 20 litre sample chamber):

- Zone 1: 2367.2 – 2370.7m (3.5m sand: 3.0 m oil pay, 22% avg. net pay porosity)

- WLT #1: 2368.3 m (Rec. 9.5 litres of oil-flecked water / mud filtrate)

- WLT #2: 2368.0 m (Rec. 19 litres of oil flecked water / mud filtrate)

Erie D-26 was drilled near the Wyandot well testing a similar structure though closer to the basin-bounding hingeline fault. Missisauga and Mic Mac formations sandstones have good to excellent porosity, with fair to good porosity in the older Mohican Formation sandstones. Two thin oil zones were encountered in the Mic Mac Formation and evaluated with the FIT wireline tool:

- Zone 1: 1892.0 – 1918.8 m (26.8 m sand with 5.5 m oil pay over water & 28% avg. porosity). The OWC is observed in the sand. FIT #1 recovered 0.7 ft^3 gas and 20 litres of oil-flecked water / mud filtrate.

- Zone 2: 1809.8 – 1812.3 m (2.5 m sand: 2.5 m oil pay, 27% avg. net pay porosity). FIT #2 recovered 20 litres of oil-flecked water / mud filtrate (16-18º API oil).

The Missisauga H-54 well (1970) had minor oil staining at the base of the Logan Canyon formation while Mic Mac H-86 had minor oil staining at the top of the Missisauga sandstones.

Parcel 4

Eight wells were drilled in Parcel 4. The three wells, Chippewa L-75 (1971) and Chippewa G-67 (1971), and Peskowesk A-99 (1985) were drilled on salt structures and all had scattered oil staining.

Peskowesk A-99 (1985) was drilled with oil based mud, so observed oil staining was questionable. Good to excellent porosity sands were encountered in the Missisauga Formation and poor to very good sands were encountered in the Mic Mac Formation.

The Tuscarora D-61 (1970) well encountered excellent porosity sands in the Mississauga and fair to very good porosity sands in the Jurassic, but encountered no hydrocarbons.

North Banquereau I-13 (1982) was drilled on a rollover anticline with minor mud gas shows and kicks in the Missisauga, Mic Mac, and Abenaki formations.

SW Banquereau F-34 (1983) was drilled on a rollover anticline with a significant gas show. DST #3 flowed 0.6 MMscf/d in a Missisauga sandstone. There were also minor gas shows in a few Missisauga, Mic Mac and Verrill Canyon sands.

Sauk A-57 (1971) and Citadel H-52 (1980) were drilled on rollover anticlines with no hydrocarbon indications.

The Banquereau C-21 Significant Discovery lies outside of the Call Parcels area but borders the southern boundary of Parcels 4 and 5. This rollover anticline was drilled in 83 m of water by Petro-Canada in 1982. Gas was discovered in shallow marine sands of the top Missisauga formation (DST #2: 20 MMcf/d gas & 230 bbls/d condensate), and the base of the Logan Canyon formation (Cree Member: DST #3: 0.8

MMcf/d gas). The reservoir sands demonstrated sustained flow on tests, and therefore the field was designated as a Significant Discovery.

Parcel 5

Seven wells were drilled on Parcel 5. Huron P-96 (1970) was the only well drilled on a salt structure and did not encounter any hydrocarbons. The remaining six wells were drilled on rollover structures.

Louisbourg J-47 (1983) and penetrated over 1800m of Jurassic section. The Mic Mac Formation at this location is carbonate rich with numerous thick, tight limestone intervals. The Mic Mac sands in J-47 generally have porosities less than 10% and are either wet or tight. An exception was a gas-charged sandstone at 5786.5 – 5799.0 m that was tested (DST #1: 5785.7 – 5799.5 (12.5 m sand) with an approximate flow rate of 5.0 MMscf/d. An engineering study conducted by the Operator indicated that the well would have flowed at higher rates, possibly up to 28.75 MMscf/d, had there not been mechanical difficulties during the test.

Esperanto K-78 (1971) penetrated approximately 600m of the Mic Mac Formation. The Missisauga and Mic Mac formations had very high net to gross (N/G) intervals and all sands are wet, probably as a consequence the poor sealing potential. The average porosities of the Missisauga sands range from 20-26%, while the average porosities of the Mic Mac sands range from 19-22%. The high porosity is due in part to shallow depth of burial of sands as top Missisauga is at 2280m and top Mic Mac at 2973m.

West Esperanto B-78 (1982) penetrated over 2800m of Jurassic section. The Missisauga and first 1000m of the Mic Mac have high N/G intervals and all sands are wet. The last 1000m of the well is shaley, and has low N/G with porosities generally less than 10%. As in the Esperanto well, the high N/G intervals would have poor sealing potential. Average porosities of the Missisauga sands are 20-24% while average porosities of the Mic Mac sands are highly variable ranging from ~10-22%.

Hesper I-52 (1976) drilled a strong amplitude anomaly caused by a basaltic flow just above the Naskapi Member shale and reached TD at only 2804 m.

Hesper P-52 (1984) was drilled 450 m away to avoid the basalt and continued to 5679 m but encountered no hydrocarbons.

South Griffin J-13 (1984) did not encounter any hydrocarbons.

Parcel 6

Only two wells were drilled on Parcel 6. Mobil drilled both Dauntless D-35 (1971) and Sachem D-76 (1975). Tight limestones were encountered in the targeted MicMac Formation and no hydrocarbons were detected.

 No 3D seismic data has been acquired over any areas of Parcels 2 – 6.

5. Potential Traps and Reservoirs.

There are proven oil reserves at Penobscot L-30 above the Missisauga Ridge and oil pay at Mic Mac J-77 and D-89 above the Mic Mac Ridge. Both of these ridges cross Parcels 1, 2 and 3 (**Figure 2.3**). On Parcel 1 there is also gas pay in Mariner I-85 and Emma N-03. An active petroleum system has been confirmed although its age is uncertain.

Good potential exists for Cretaceous and Jurassic clastic reservoir sand on all six blocks. High quality sands have been identified at most intervals penetrated. The majority of wells drilled on salt structures were located using 1970's vintage 2D seismic data with a few from the 1980's, which results in very poor imaging of traps, but good potential can be expected where salt diapirs have enhanced hydrocarbon migration from deeper (Early-Middle Jurassic) source rock successions. Good quality 3D seismic data would help to identify traps involving the numerous salt structures.

There is also potential development of transgressive system tract, Early Jurassic Iroquois, Middle Jurassic Scatarie, and Late Jurassic Abenaki formations bioherms along the basin hinge zone during periods of rising sea level or flooding. There are indications of a stacked, Abenaki reefs in Parcel 4 as noted below. This could be similar to the Deep Panuke gas field hydrothermal dolomitic and leached limestone reservoir, but older (lower Baccaro Member, Abenaki A2-A4). Faulted basement ridges in other locations may also facilitate development of aggradational reef complexes in other parcels.

Figure 5.1 illustrates known and conceptual plays and petroleum systems elements in the Call for Bids region.

Parcel 1

Penobscot Oil Discovery

The Penobscot field is located 30 km northeast of the Thebaud production platform in water depths ranging from 50 to 200 m. The initial well on the structure, Penobscot L-30, was drilled by Petro-Canada-Shell in 1976 to a depth of 4237.5 m in 138 m of water. **Figure 5.2** show a time structure map on blue Sand 1 marker, indicated on the dip line through the L-30 well location (**Figure 5.3**). Hydrocarbons were recovered by Repeat Formation Tester (RFT) from four Middle Mississauga sands on the down thrown side of the fault.

A second well, Penobscot B-41, was drilled by Shell-Petro Canada in 1977. This well is 3 km to the northwest and at the time was believed to be up-dip of L-30, on the same structure. The B-41 well reached a total depth of 3414 m in 118 m of water. No significant hydrocarbons shows were encountered and no formation tests were run. The stratigraphic tops in B-41 were within 10 m of the tops in the L-30 well suggesting that B-41 was not substantially up-dip of L-30. Recent seismic reprocessing and depth conversion demonstrate that B-41 may have been drilled into a separate closure. The closure to the north of the fault has not been drilled.

After the licence was relinquished by Shell, Nova Scotia Resource Limited (NSRL) obtained an Exploration Licence over the Penobscot prospect in 1989 and acquired 66 km^2 of 3D seismic (CNSOPB program number NS24-N011-001E). The interpretation report for this survey, completed in 1991, including synthetics,depth conversions and maps,is available through the Geophysical Data section under the Data tab.. A second report completed in 1992that included further mapping and reserve estimates is also available. This report identified additional potential northeast of the original mapped Penobscot prospect that has yet to be tested.

The Penobscot 3D seismic data is now owned by the Province of Nova Scotia who has made the digital SEGY data available free to the public through the CNSOPB's Geoscience Research Center (GRC). The Provincial Government also reprocessed this 3D seismic to improve data quality. Instructions for downloading both of these data sets can be found in the **Digital Data** section of the website (www.callforbids.ca).

Penobscot L-30 and B-41 - Petrophysical Assessment

A complete suite of the primary logs were acquired in both Penobscot L-30 and Penobscot B-41. Two conventional cores were cut in L-30, however both cores were cut well below the reservoir interval. In B-41 four conventional cores were cut within the Penobscot reservoir interval, (**Figure 5.4**). The Penobscot B-41 core intervals are listed below.

Core#	Interval (m MD)	Recovery
Core# 1	2499.4 – 2517.6m	Rec. 17.4m
Core# 2	2642.6 – 2660.9m	Rec. 14.3m
Core# 3	2660.9 – 2670.0m	Rec. 8.2m
Core# 4	2699.0 – 2717.9m	Rec. 3.05m

Routine core analysis was conducted on the above cores. Average core porosity of the reservoir interval is 20%, with a maximum of 32%. Average permeability of the reservoir interval is 120 mD with a maximum of over 1000 mD.

No Drill Stem Tests (DSTs) were conducted in either Penobscot L-30 or B-41, however a number of Repeat Formation Tests (RFTs) were run in L-30. The RFT fluid recoveries, from the Penobscot L-30 reservoir sands, are listed below.

Penobscot L-30 – Fluids Recovered from RFT (Sands 1 - 5 Only)					
Sand#	Depth (m)	Oil/Condensate (cc)	Gas (cu ft)	Water (cc)	Remarks
1	2480.2	3400 cc cond.	1.0	nil	
2	2504.8	900 cc oil	Nil	8,000	
2	2509.4	nil	Nil	10,250	Sample taken below Oil-Water Contact (OWC)
2	2509.4	nil	Nil	3,750	Sample taken below OWC
3	2545.4	100 cc oil	0.5	10,000	<1 m above OWC[1]

4	2639.3	3,800 cc cond.	10.0	5,200[2]	
4	2639.3	3,000 cc cond.	5.0	Nil	
5	2700.5	nil	Nil	10,250	Transition zone[3]
5	2700.5	nil	Nil	3,750	Transition zone[3]
5	2700.8	nil	Nil	9,700	Transition zone[3]

[1.] This RFT recovered mainly water due to the proximity of the oil-water contact (OWC), i.e. RFT taken <1 m above OWC.

[2.] Both RFTs run at this depth recovered considerable condensate and gas. The water recovered from this RFT is likely mud filtrate and not formation water.

[3.] These RFTs were taken only 2 m above the interpreted OWC in sand 5. The upper portion of sand 5, at the L-30 location, is within the transition zone and has a high water saturation (Sw ~70%) resulting in water recovery on RFT.

Seven normally pressured hydrocarbon bearing sands were encountered in Penobscot L-30 within the Lower Missisauga formation. As indicated by the RFT fluid recoveries, most sands appear to contain light oil/condensate and gas. It is unclear if the gas recovered from RFT is solution gas or free gas. Based on a petrophysical assessment of the zones it appears that light oil/condensate is the primary reservoir fluid.

A petrophysical assessment of the Penobscot L-30 and B-41 was conducted using available log, core and RFT data (**Figure 5.4**). The Penobscot reservoir sands are wet in Penobscot B-41, however seven hydrocarbon bearing zones were encountered in Penobscot L-30. Each sand in L-30, was interpreted to have a separate log defined oil-water contact. The results of the Penobscot L-30 petrophysical assessment are summarized below.

Penobscot L-30 – Reservoir Properties					
Sand	Top (m MD)	Base (m MD)	Net Pay (m TVD)	Net Pay Por. (%)	Sw (%)
1	2477.6	2484.9	1.2	19	49
2	2503.0	2530.9	4.6	21	46
3	2542.0	2546.6	2.1	18	41
3A	2558.5	2594.6	Wet	N/A	N/A
4	2638.0	2669.0	4.3	19	45
5*	2699.2	2758.5	<0.5	N/A	N/A
6*	2795.5	2805.4	<0.5	N/A	N/A

7*	2835.3	2912.8	<0.5	N/A	N/A

* Penobscot L-30 was drilled on the flank of the South Penobscot structure and thus encountered relatively thin oil columns at the L-30 location. There is approximately 15 m of additional structural relief, for each of the Penobscot sands, updip of L-30. Sands 5 -7 have interpreted oil-water contacts within a few metres of the top of each sand. As a result, the top portion of these sands is transitional and has high water saturation (~70%). Sands 5 – 7 appear to have very thin (<0.5 m) oil pay over water at the very top of the each sand which supports the interpretation that the sands are transitional at the L-30 location.

Penobscot Reserve Estimates

The Penobscot field is directly analogous to the Cohasset/Panuke oil fields located on the Scotian Shelf approximately 60 km to the southwest. Combined, Cohasset and Panuke produced 44.5 MMBbls of light sweet oil from high quality, relatively thin, reservoir sands located within the Logan Canyon and upper Missisauga formations. The fields were on production from 1992 – 1999. The total volume of oil produced from Cohasset was 28.3 MMBbls and total Panuke production was 16.2 MMBbls. This demonstrates that relatively modest offshore oil fields can be economically viable.

Penobscot is interpreted to contain three separate oil accumulations (**Figure 5.2**)

1. South Penobscot   L-30 well area,

2. North Penobscot   North of the main fault,

3. *Northeast Penobscot   North of the second fault to the NE.*

South Penobscot contains high confidence oil reserves. North & Northeast Penobscot have not been tested by drilling and therefore contain lower confidence (possible) reserves. Due to the different confidence levels, between the northern and southern areas of the field, each region was assessed separately. The CNSOPB conducted a probabilistic resource assessment of these two regions, South Penobscot (proven reserves) and North/Northeast Penobscot (possible reserves), and the results are tabulated below.

South Penobscot - Original Oil in Place			
P90 (E6M3)	P50 (E6M3)	P10 (E6M3)	Mean (E6M3)
6.2	10.3	14.5	10.4
P90 (MMBbls)	P50 (MMBbls)	P10 (MMBbls)	Mean (MMBbls)
39.3	64.9	91.3	65.3
North & Northeast Penobscot - Original Oil in Place			
P90 (E6M3)	P50 (E6M3)	P10 (E6M3)	Mean (E6M3)

6.0	12.4	21.3	13.1
P90 (MMBbls)	P50 (MMBbls)	P10 (MMBbls)	Mean (MMBbls)
37.7	77.9	134.1	82.4
Total Penobscot - Original Oil in Place			
P90 (E6M3)	P50 (E6M3)	P10 (E6M3)	Mean (E6M3)
12.2	22.7	35.8	23.5
P90 (MMBbls)	P50 (MMBbls)	P10 (MMBbls)	Mean (MMBbls)
77.0	142.8	225.4	147.7

South Penobscot - Recoverable Oil in Place			
P90 (E6M3)	P50 (E6M3)	P10 (E6M3)	Mean (E6M3)
2.1	3.6	5.2	3.6
P90 (MMBbls)	P50 (MMBbls)	P10 (MMBbls)	Mean (MMBbls)
13.4	22.4	32.8	22.8
North & Northeast Penobscot - Recoverable Oil in Place			
P90 (E6M3)	P50 (E6M3)	P10 (E6M3)	Mean (E6M3)
2.1	4.3	7.6	4.6
P90 (MMBbls)	P50 (MMBbls)	P10 (MMBbls)	Mean (MMBbls)
13.0	26.8	47.5	28.8
Total Penobscot - Recoverable Oil in Place			
P90 (E6M3)	P50 (E6M3)	P10 (E6M3)	Mean (E6M3)
4.2	7.9	12.8	8.2
P90 (MMBbls)	P50 (MMBbls)	P10 (MMBbls)	Mean (MMBbls)
26.4	49.2	80.3	51.6

Deep Penobscot

A Late Jurassic carbonate bank edge extends beneath the Penobscot discovery well TD. Although tight carbonates were encountered in the L-30 well, there is potential for porosity development at the margin edge.

Prospectivity of Parcels 2-6

There are 28 wells drilled throughout Parcels 2-6 in the Abenaki and Huron subbasins. These wells tested four basic plays/structure types: 1) salt crest and shallow salt flanks 2) forced-folds over basement related highs 3) rollover anticlines and 4) interbedded clastics and carbonates **(Figure 5.6)**.

The salt-related plays tested condensed onlapping strata in 1970 with no success (Iroquois J-17, Huron P-96, Chippewa G-67 and Chippewa L-75). Erie D-26 and Wyandot E-53 tested forced folds over basement highs within the Erie Graben Complex; a thin oil zone was encountered in Mohican sands at Wyandot **(Figure 5.8)**. Forced fold tests on the Missisauga Ridge were not successful (Missisauga H-54 and Peskowesk A-99).

The rollover anticlines tested proximal regions of the basin where the Jurassic and Cretaceous deposits have a high net to gross where there may be a lack of an adequate sealing horizon **(Figure 5.6)**. These wells were either wet (Tuscarora D-61, Esperanto K-78 and West Esperanto B-78) or had thin oil columns (Mic Mac J-77 and Mic Mac D-89).

A test of folded, interbedded clastic and carbonate systems was successful at Louisbourg J-47 and gas was encountered in a 13 m Mic Mac Formation sand.

Wells drilled across Parcels 2-6 have proven there is a working petroleum system (for both oil and gas) in this area. One of the risks in these parcels may be seal. Play tests in proximal positions in these parcels show an abundance of both Jurassic and Cretaceous coarse grain siliciclastics. The Naskapi shale may provide a top seal for upper Cretaceous sands when an adequate shale thickness is attained **(Figures 5.6 and 2.18)**.

Carbonates may also have potential to provide a Jurassic top seal in this high net to gross environment. The proper combination of thick porous Jurassic sands and sealing carbonates may exist inboard of the Louisbourg J-47 well where few wells have been drilled **(Figure 5.6)**. For traps identified within the central parts of these parcels (i.e. between the Esperanto and Louisbourg wells) the required balance of reservoir quality sand and sealing carbonates may be encountered.

Other untested plays such as Abenaki carbonate reefs and subsalt plays are discussed further in the below Parcel specific sections.

Parcel 2

Figure 5.5 shows the J150 horizon time structure map, indicating locations of the seismic line used to highlight features on Parcels 2-6. The best quality seismic data in the most favourable locations cannot currently be shown because of data disclosure policies.

Figure 5.7 displays Husky (1982) dip lines 82-619 and 82-619a through Parcel 2, starting on the LaHave Platform, crossing the Erie Graben Complex and continuing into the Abenaki Subbasin. The Iroquois diapir above the Mic Mac Ridge has only been tested by one well, Iroquois J-17 drilled in 1970 that encountered minor oil staining. This seismic line illustrates the poor quality of the salt imaging even though this data was acquired more than 12 years after the diapir was drilled. Improved definition of salt structures using 3D seismic could define potential traps along this 20 km long diapir.

The Abenaki salt diapir is adjacent to the Missisauga Ridge. This 30 km long diapir was penetrated by two wells in 1970, 27 km west of this line. Abenaki L-57 had minor oil staining and Abenaki J-56 had gas charged mud. New 3D seismic could also identify potential traps along this system.

Above the Missisauga Ridge there is potential for roll over closure NE of the Abenaki Diapir on the J150 horizon (**Figure 5.5 & 2.6**) and SE of the diapir on the J163 horizon (**Figure 2.5**). There is also turtle structuring in this area as a result of salt evacuation into the diapir.

With improved imaging, a subsalt play could also be developed both in the Erie Graben Complex and in the Abenaki Subbasin. This is shown on Figure 5.8

Parcel 3

Figure 5.8 presents Petro-Canada (1982) dip lines 531 and 531a through Parcel 3 starting on the La Have platform, crossing the Erie Graben Complex and passing 5 km east of Wyandot E-53 (1970).   The high net to gross and porosity of Missisauga and Mic Mac formation sandstones along with the thin Naskapi shale in this area require development of a local seal in order for a structure to be prospective.

Fair to good porosity in Mohican Formation sandstones at the base of the Wyandot E-53 well provides a promising exploration target throughout this graben complex. The combination of good quality Mohican sands, a well-developed Misaine shale seal, and proximity to early Jurassic source rocks could be prospective.

The untested subsalt section could also be prospective in the Erie Graben Complex given its relatively shallow burial depth and proximity to possible Late Triassic source rocks.

The seismic line continues over the Mic Mac Graben which lies above the Mic Mac Ridge. This graben is along trend with minor oil pay in the Mic Mac J-77 (1970) and Mic Mac D-89 (1970) wells which are 18km to the east. J-77 is drilled into the central area of the graben while D-89 tested a small closure on the footwall of the northern fault. The Naskapi Member begins to thicken in this area providing better sealing potential.

Extensions of the bounding faults for the Citnalta and Arcadia Significant Discoveries (SD) trend across the southern portion of Parcel 3 **(Figure 5.5)**. These SDs have gas pay in Missisauga and Mic Mac sandstones. The Citnalta gas sands also have unusually high liquids content.

Parcel 4

Figure 5.9 illustrates Petro Canada (1982) seismic dip line 505a through Parcel 4 with rapid expansion of the Early Jurassic succession into the Huron Subbasin. Chippewa G-67 (1970) was drilled on the flank of a salt diapir encountering minor oil staining in Missisauga sandstones. Positioning of this well on the salt structure in 1970 was probably suboptimal given the seismic quality.

This line reveals a poorly imaged, but thick, untested, Late Jurassic, stacked carbonate reef buildup at around 4.5 seconds (blue arrow and red highlights).The reef is better imaged on more recent seismic data and has not been penetrated by any wells. The reef is similar in morphology to the Deep Panuke gas field, although here it was buried earlier by clastics, possibly near Kimmeridgian time. The reef complex at Deep Panuke continued through the Tithonian and was buried by Missisauga sandstones. The nearby Sauk A-57 well just penetrates the top of the Jurassic at 4766m.**Figure 5.10** illustrates that there is also potential for the development of Early Jurassic Iroquois or Middle Jurassic Scatarie bioherms along the Missisauga Ridge during periods of rising sea level or flooding.

Parcel 5

Figure 5.11 shows Petro Canada (1982) dip line 503a through Parcel 5 starting on the LaHave Platform, across the faulted basin hingeline, out into the Huron Subbasin and continuing to the South Griffin Ridge. Salt evacuation and diapirism has strongly influenced Jurassic Mic Mac progradation into the Huron Subbasin as detailed in **Figure 5.6**. Good Jurassic reservoir sands at Esperanto K-78 can be correlated to clinoforms that are expanding into this basin.

Salt expelled along the South Griffin Ridge provides opportunities for traps that could be defined with 3D seismic data.The South Griffin J-13 well (1984) was drilled to 5900m in the Late Jurassic Mic Mac above the South Griffin Ridge. Although no hydrocarbons were encountered in this well, the South Griffin Ridge provides plenty of faulting and structuring with the Naskapi shale providing a much better seal in this area.

Parcel 6

The Petro Canada (1982) dip seismic line 4055 selected to illustrate play concepts in Parcel 6 also crosses a small portion of Parcel 5 on the LaHave Platform **(Figure 5.12)**. This line intersects numerous Jurassic and Cretaceous progradational packages interpreted to consist of both clastics and carbonates. This line is also shown in **Figure 5.6** with an enhanced interpretation based on lithologies intersected in nearby wells.

Potential plays within Parcel 6 are rollover anticlines in the high net to gross Jurassic and Cretaceous intervals, subsalt traps in the southern end of the parcel near the South Griffin Ridge (beneath a poorly imaged salt canopy?) and interbedded clastic and carbonate systems similar to that penetrated in the Louisbourg J-47 well **(Figures 5.6 and 5.12).**
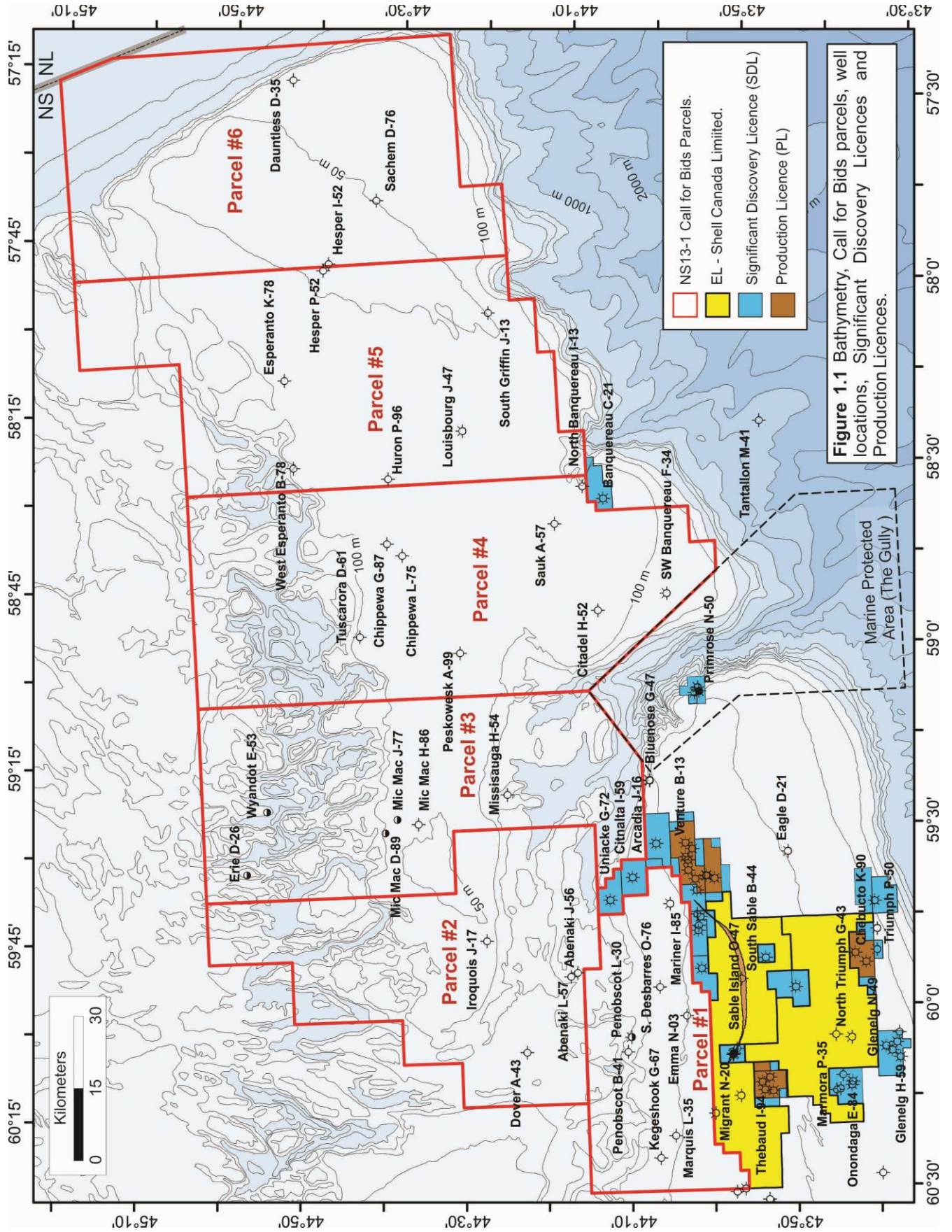
Figure 1.1 Bathymetry, Call for Bids parcels, well locations, Significant Discovery Licences and Production Licences.
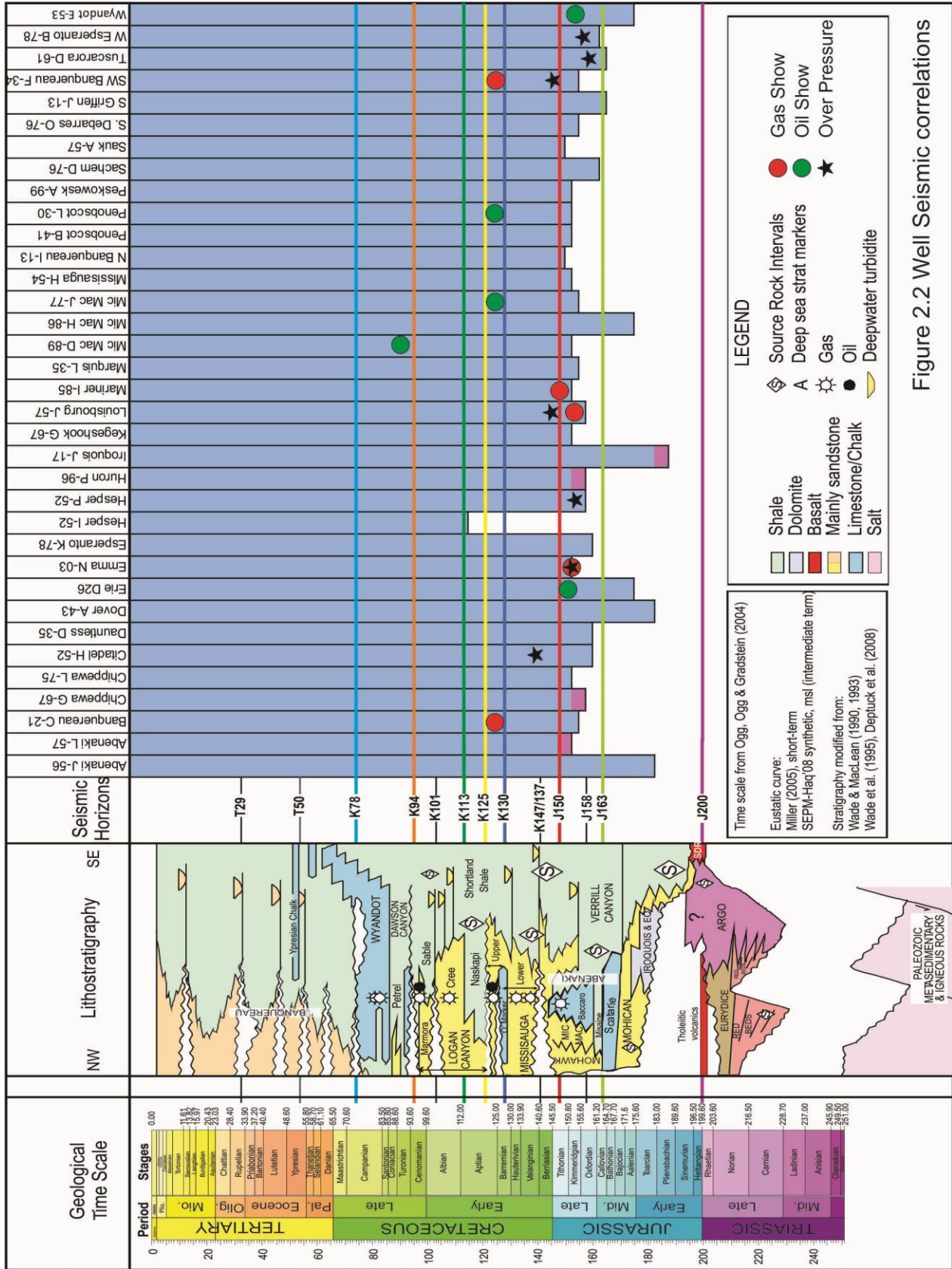
Figure 2.2 Well Seismic correlations

700 ms

twt

7500 ms

No interpretation
of J200 (poor data
quality)

Southern extent of study area

Contour interval = 250 ms
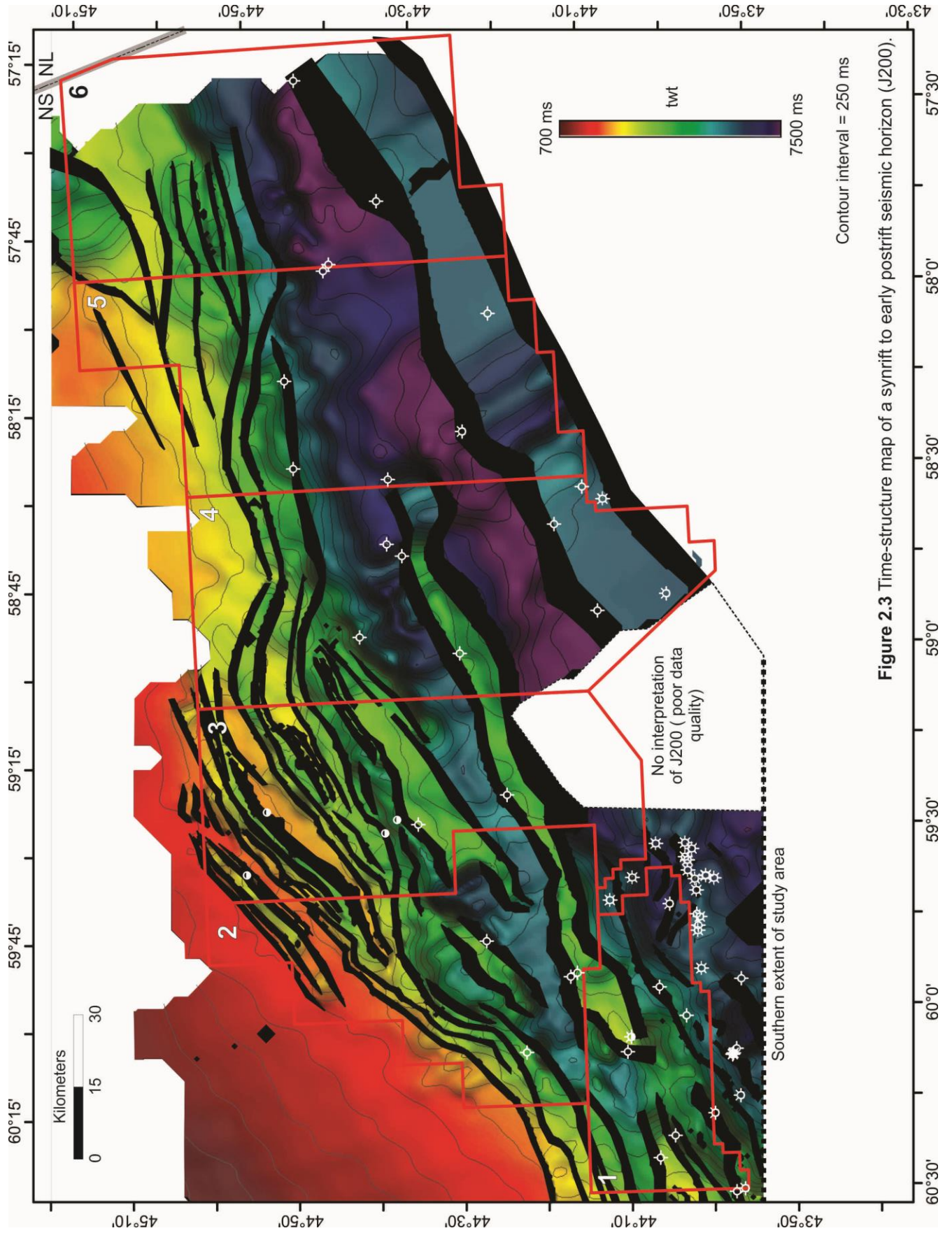
Figure 2.3 Time-structure map of a synrift to early postrift seismic horizon (J200).
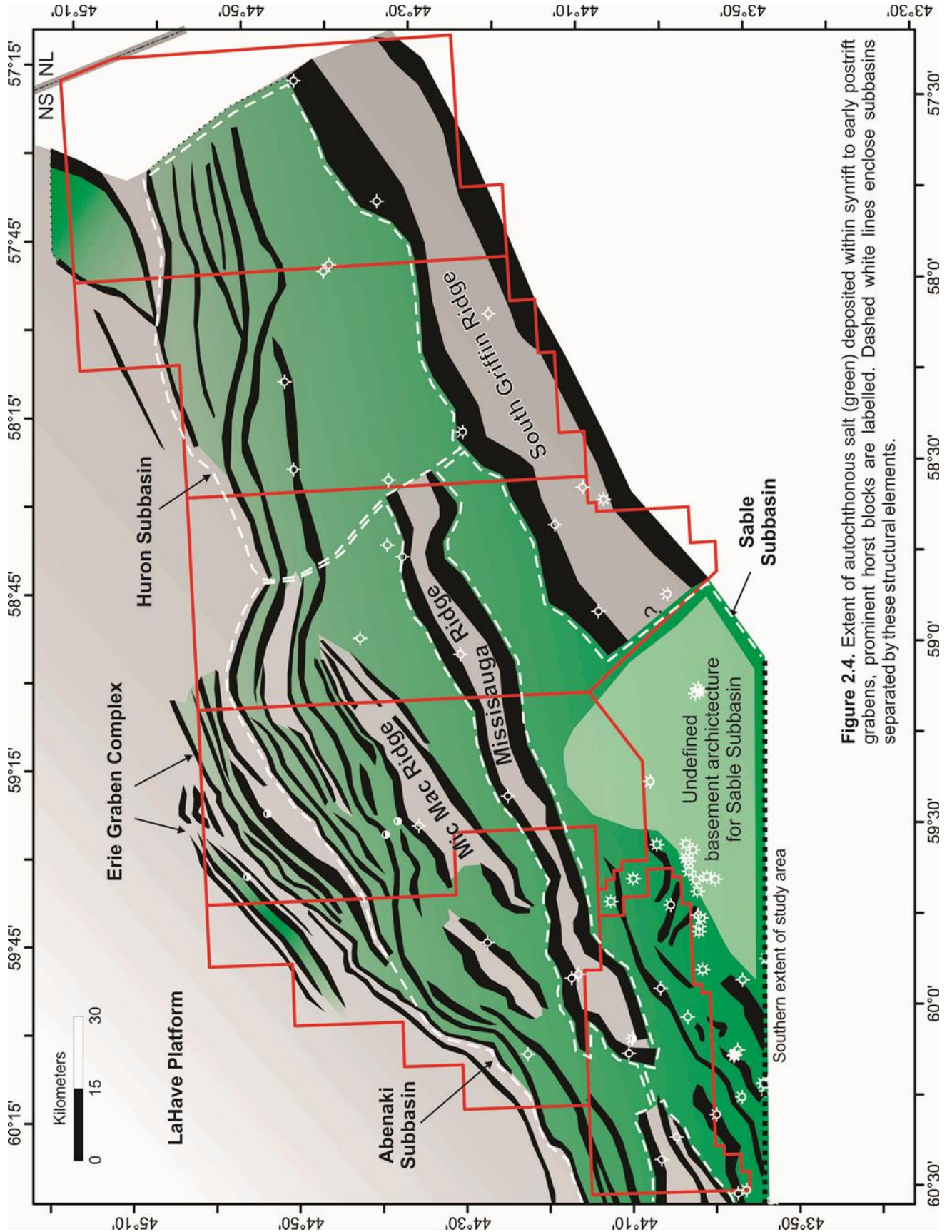
Figure 2.4. Extent of autochthonous salt (green) deposited within synrift to early postrift grabens, prominent horst blocks are labelled. Dashed white lines enclose subbasins separated by these structural elements.
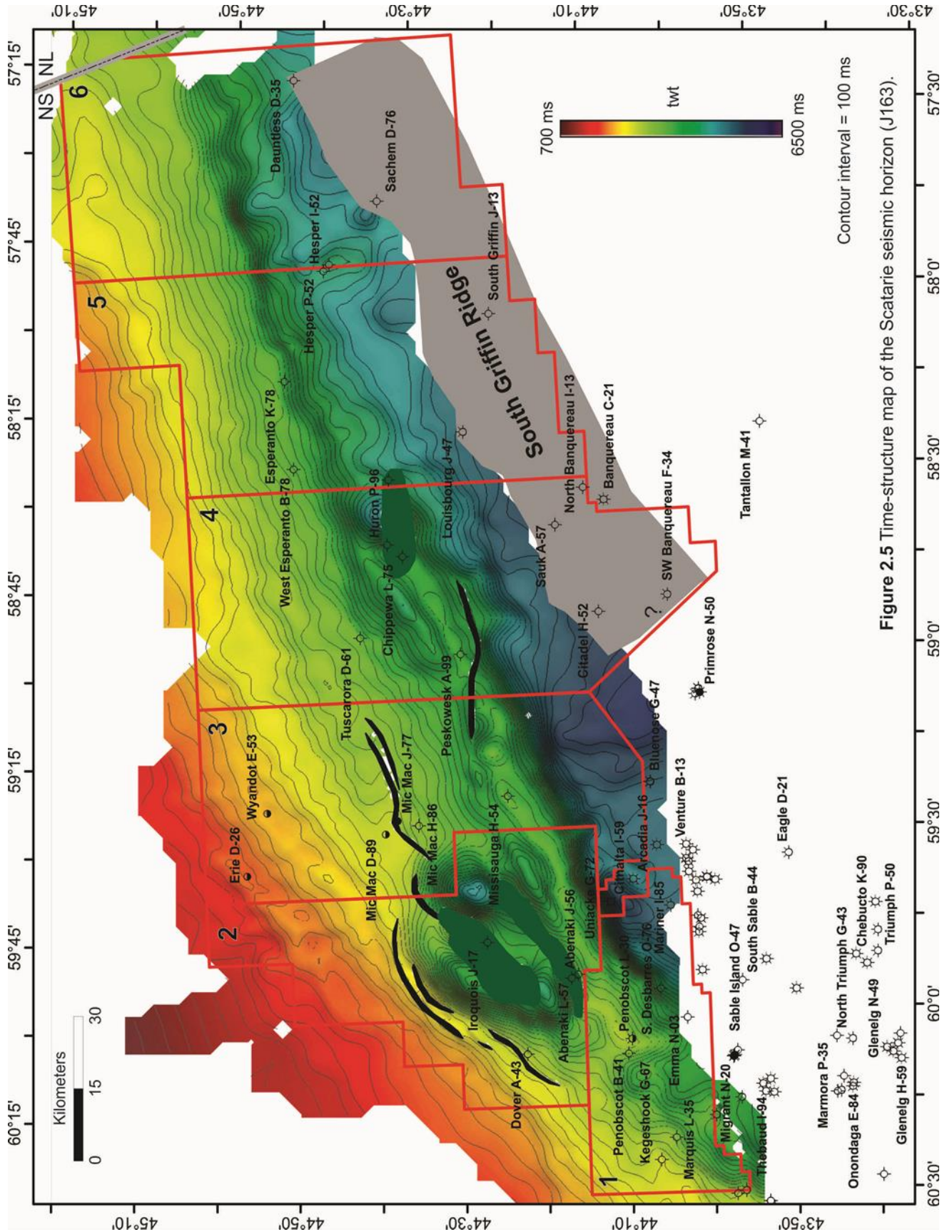
Figure 2.5 Time-structure map of the Scatarie seismic horizon (J163).
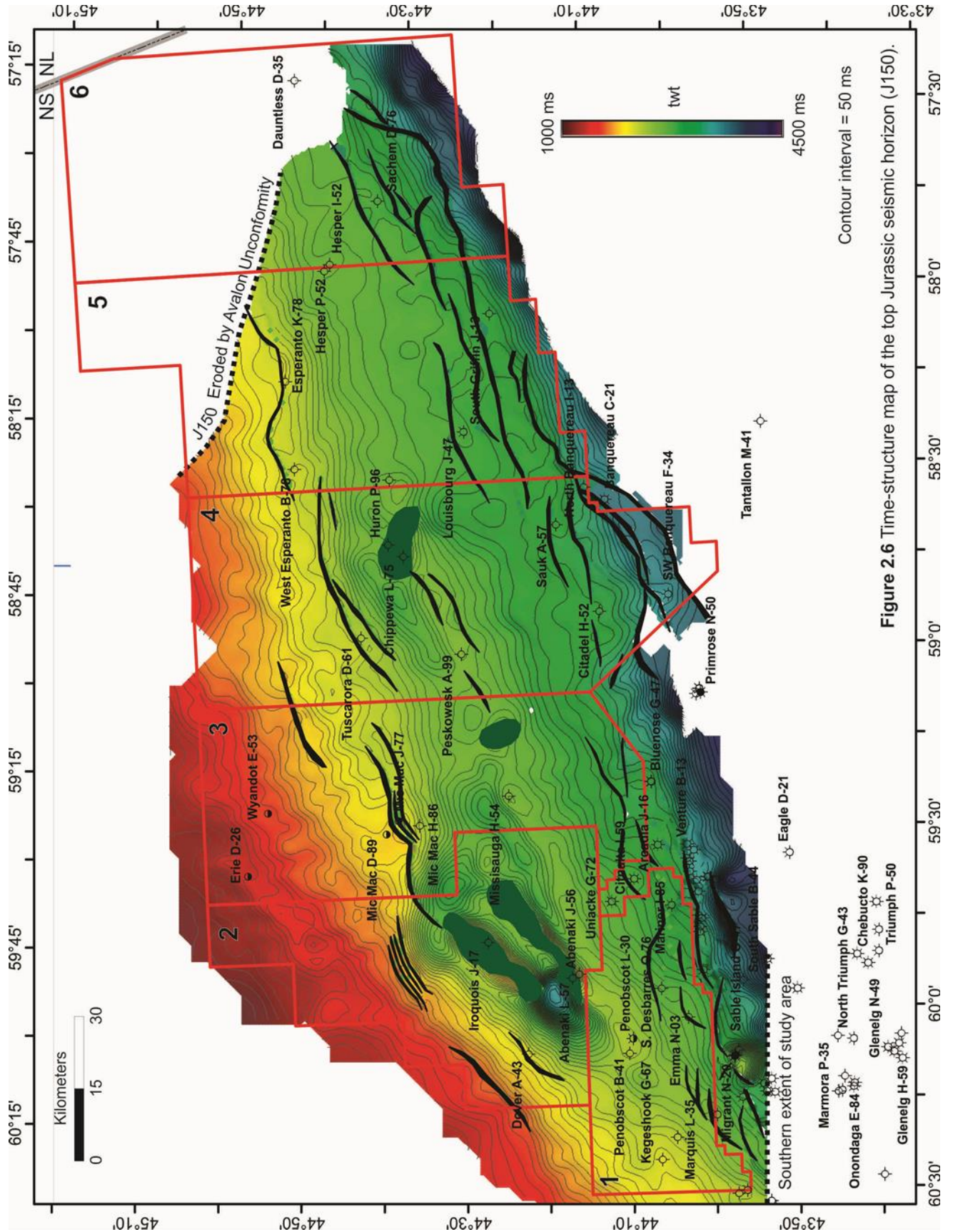
Figure 2.6 Time-structure map of the top Jurassic seismic horizon (J150).
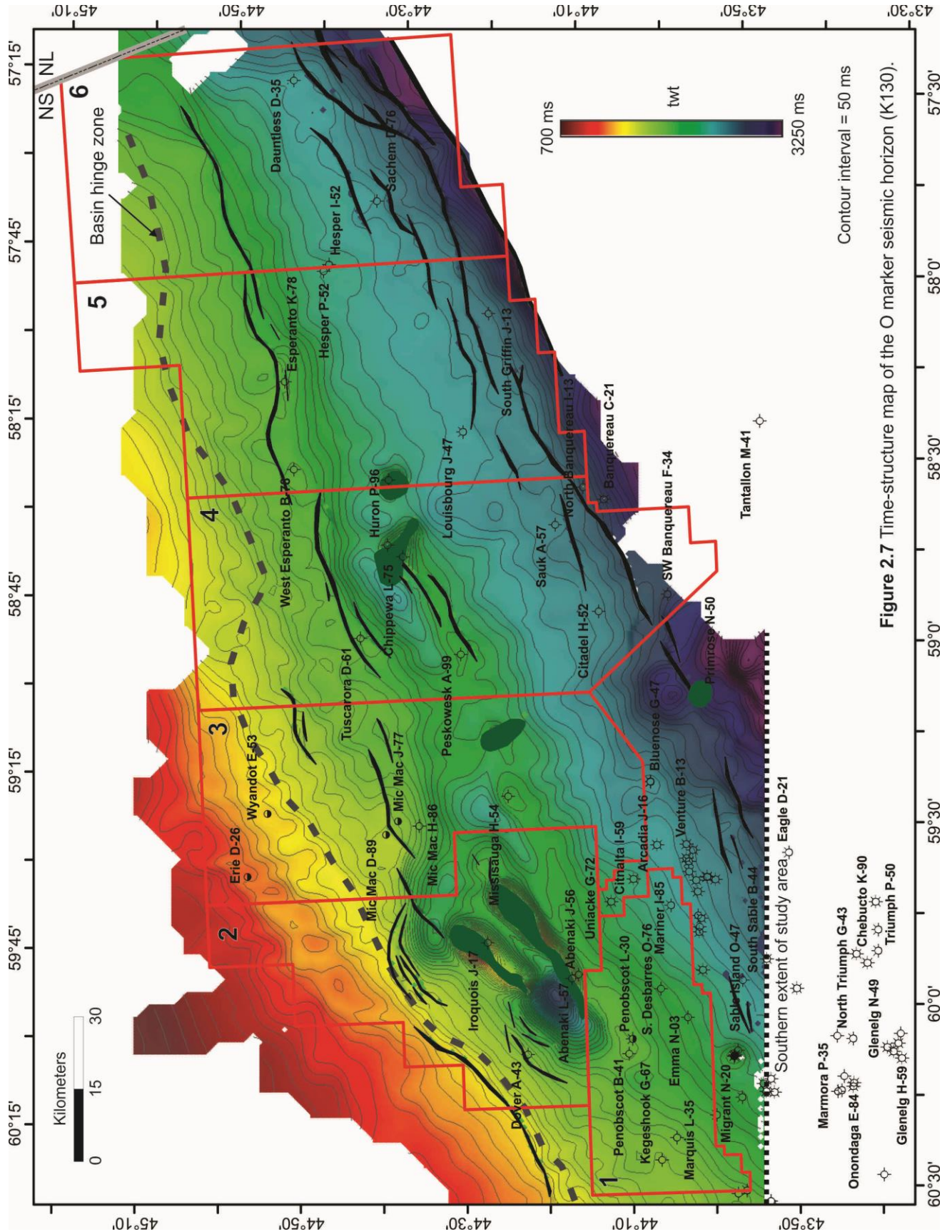
Figure 2.7 Time-structure map of the O marker seismic horizon (K130).
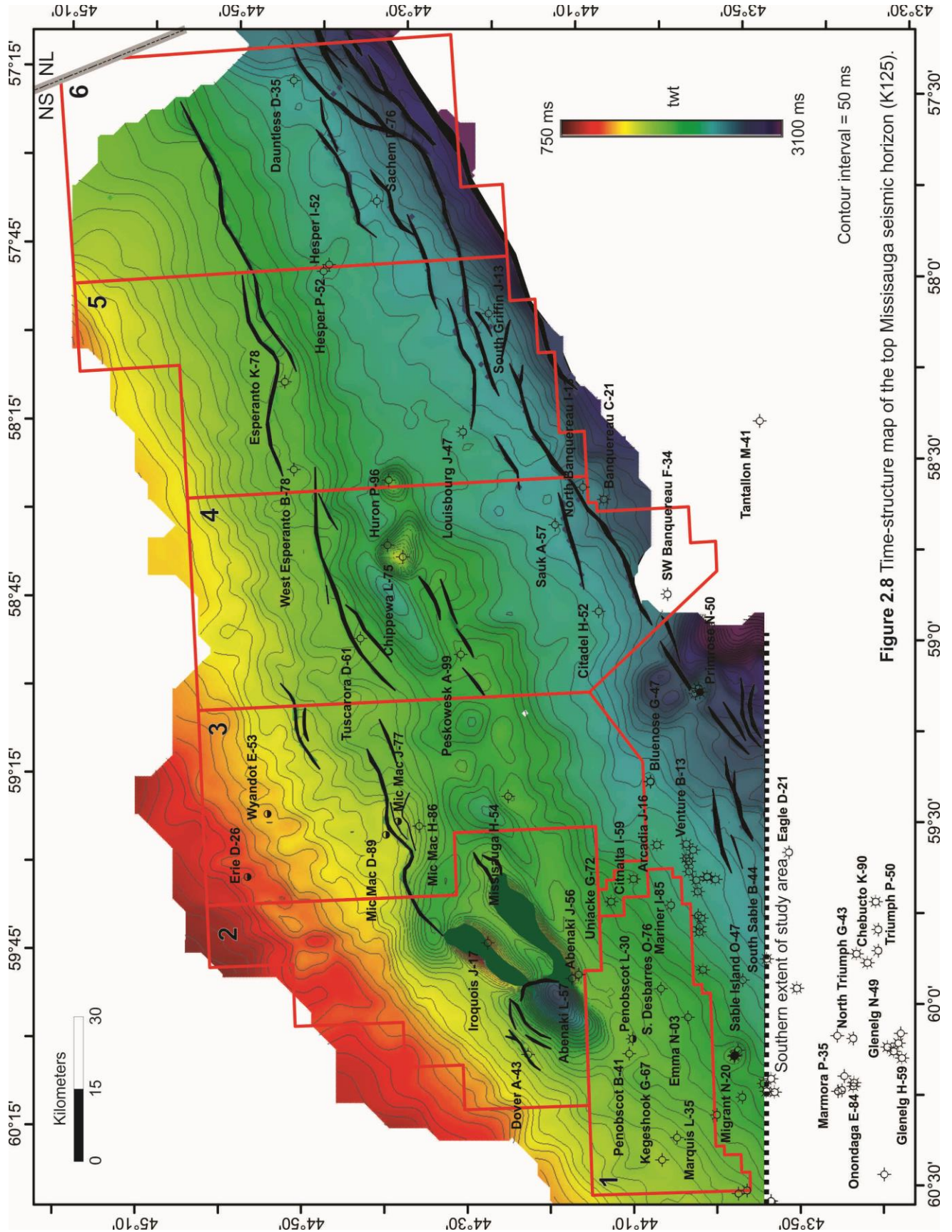
Figure 2.8 Time-structure map of the top Missisauga seismic horizon (K125).

Figure 2.9 Time-structure map of the top Naksapi seismic horizon (K113).

Contour interval = 50 ms

Figure 2.10 Time-structure map of the top Petrel seismic horizon (K94).

Contour interval = 50 ms
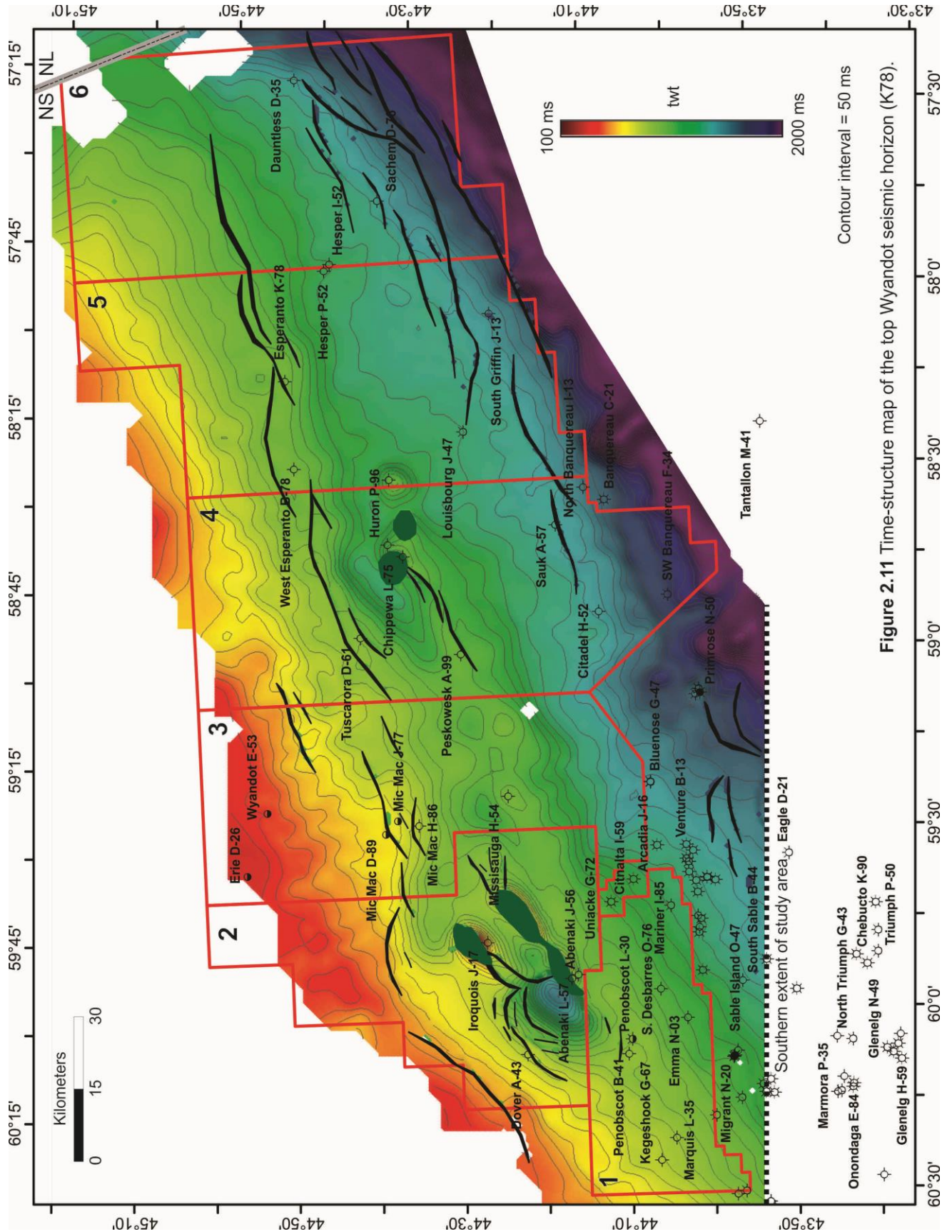
Figure 2.11 Time-structure map of the top Wyandot seismic horizon (K78).

Contour interval = 50 ms

Figure 2.12 Isochron of the Early Jurassic Scatarie, Mohican and Iroquois formations (J163-J200).
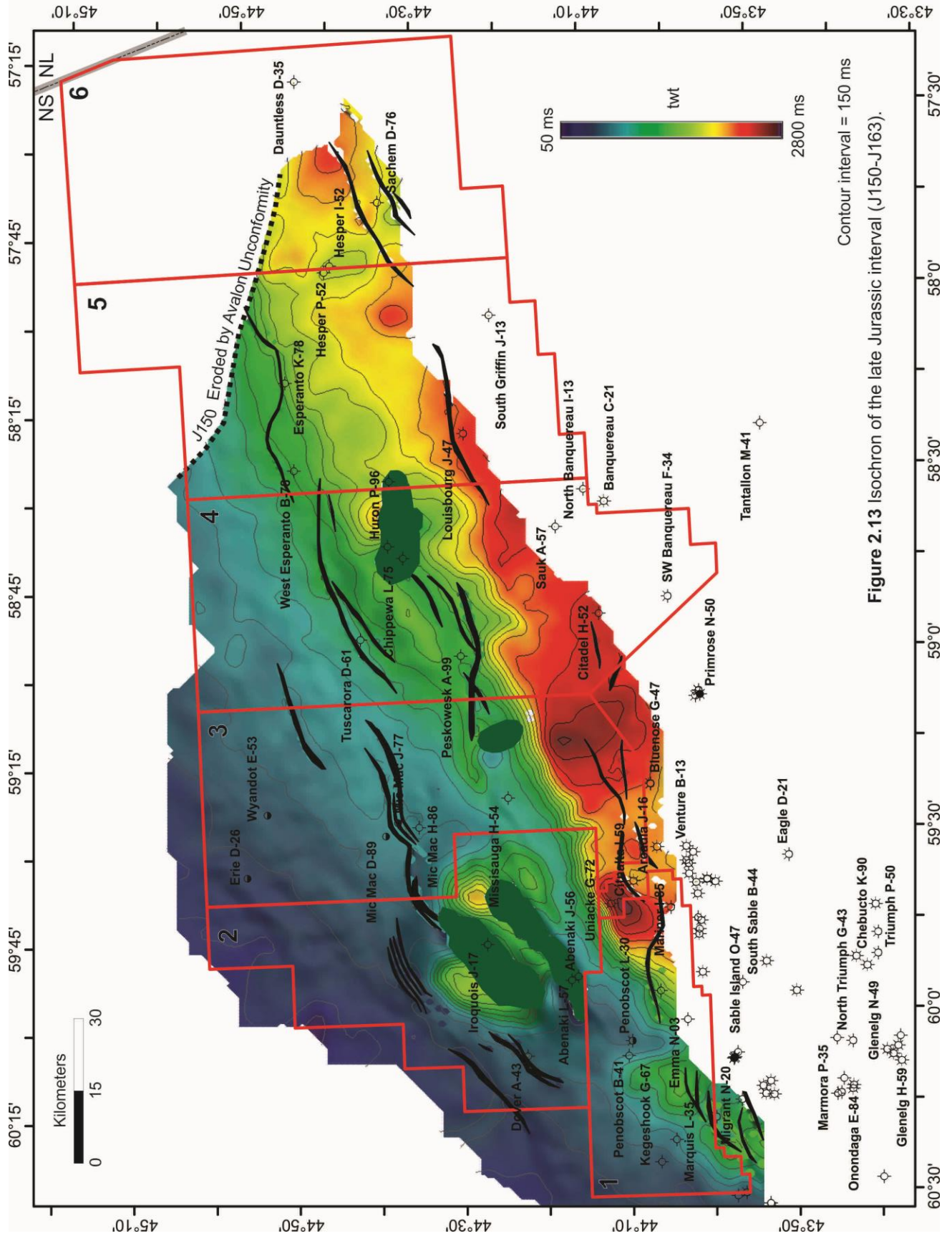
Figure 2.13 Isochron of the late Jurassic interval (J150-J163). Contour interval = 150 ms.
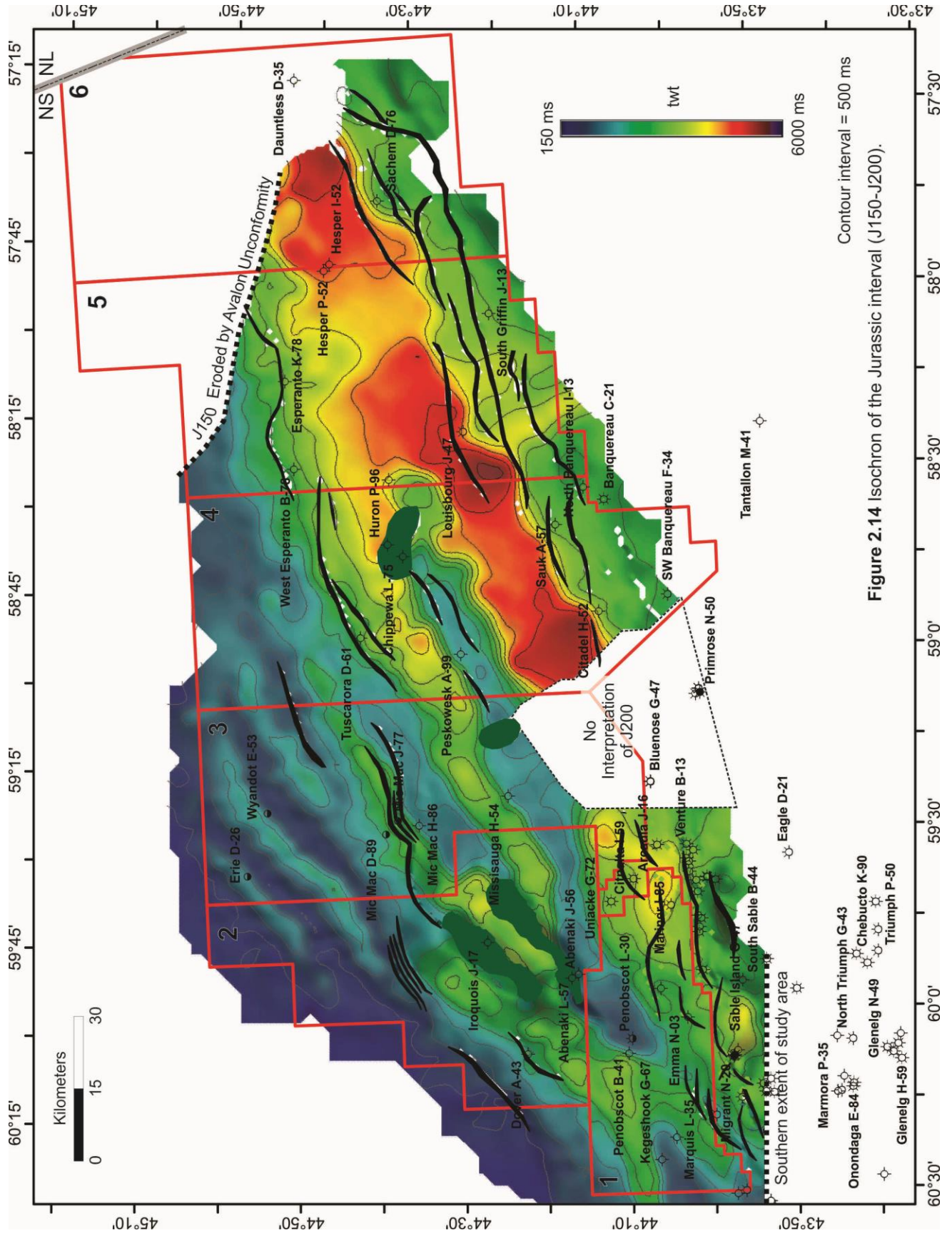
Figure 2.14 Isochron of the Jurassic interval (J150-J200).

Contour interval = 500 ms.

Figure 2.15 Isochron of the lower Missisauga interval (K130–J150)

Contour interval = 50 ms
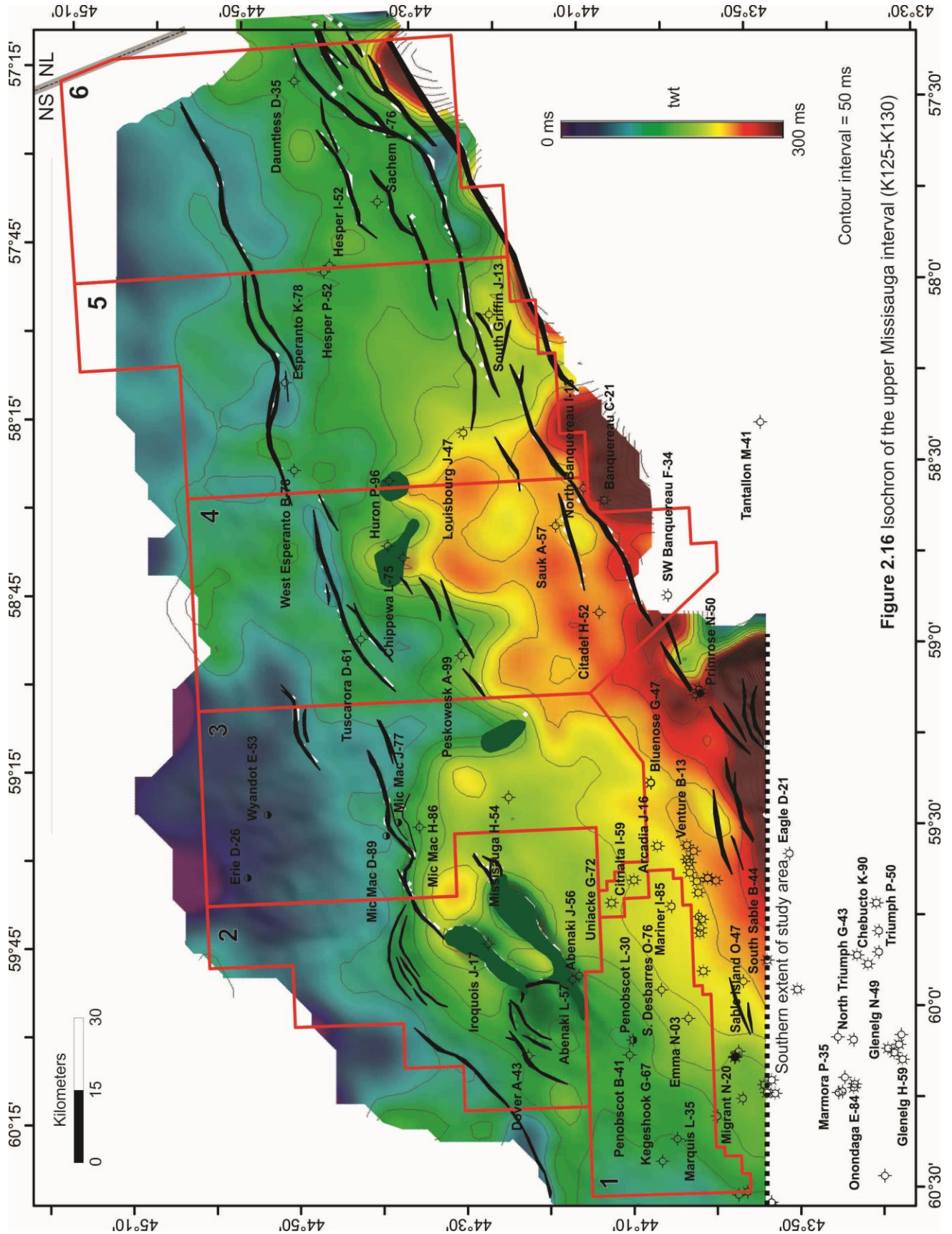
Figure 2.16 Isochron of the upper Missisauga interval (K125-K130)

Contour interval = 50 ms
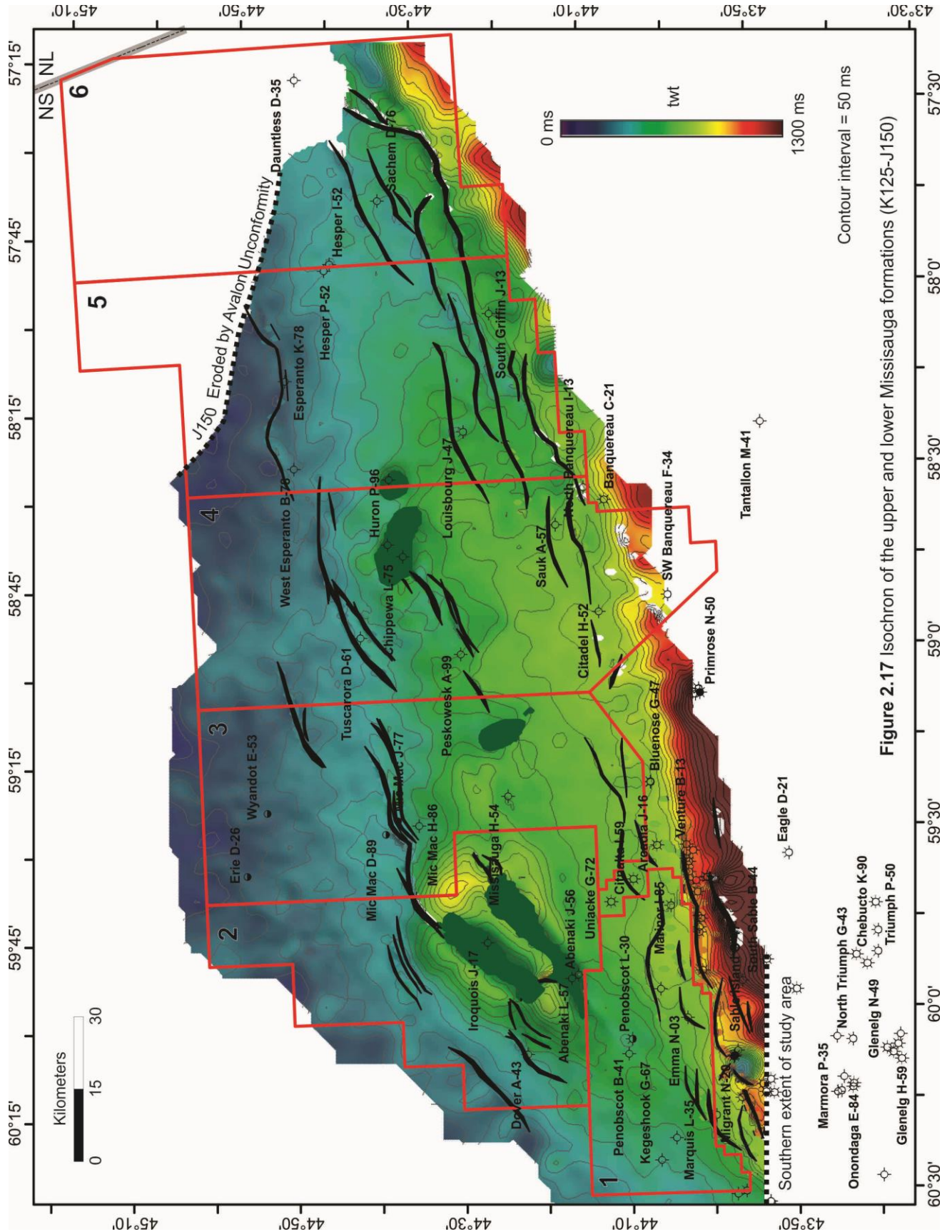
Figure 2.17 Isochron of the upper and lower Missisauga formations (K125-J150)

Figure 2.18 Isochron of the Naskapi Formation (K113-K125)

Contour interval = 20 ms
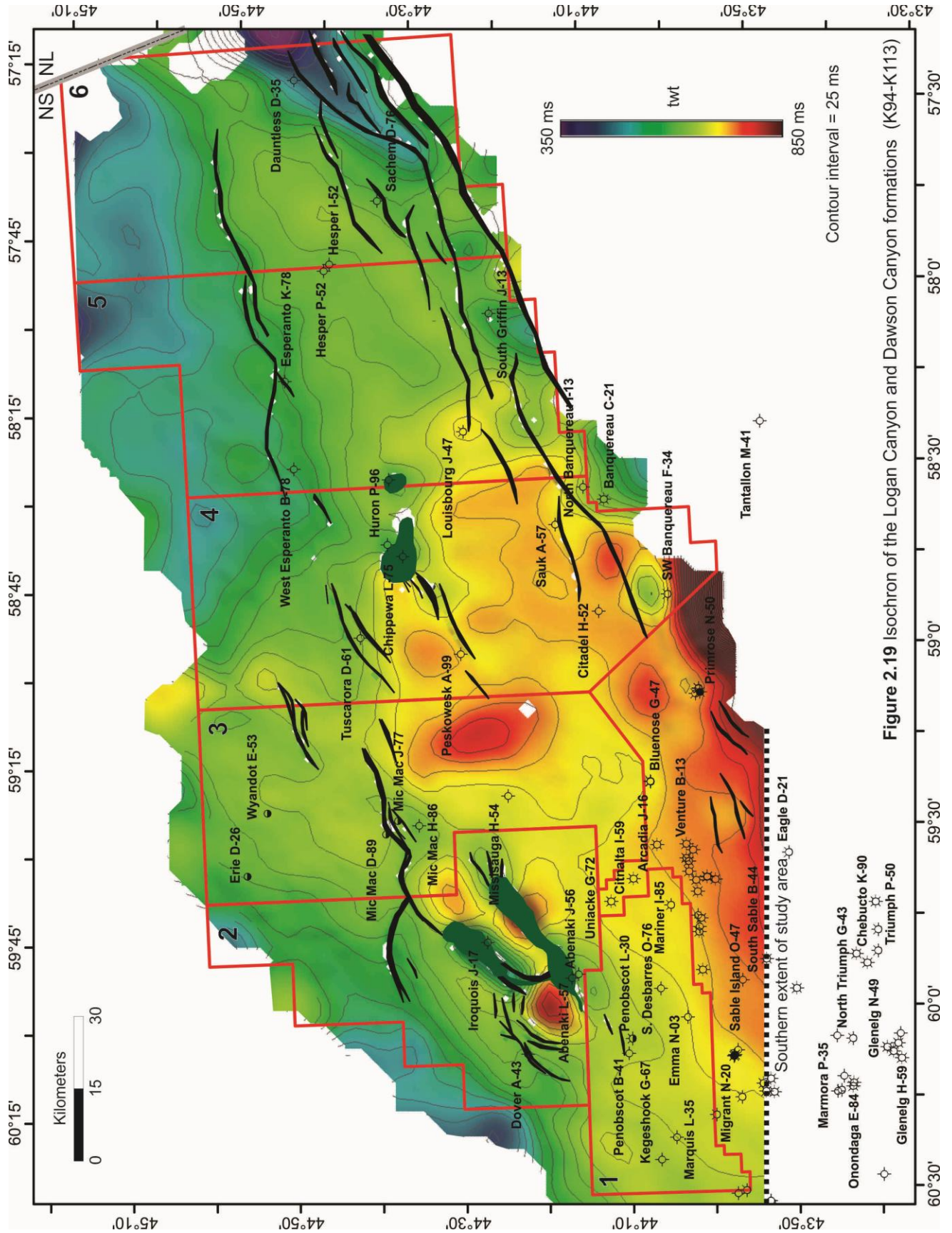
Figure 2.19 Isochron of the Logan Canyon and Dawson Canyon formations (K94-K113)

Figure 3.1 Transformation ratio map of a Tithonian source rock, overlain by Parcels 1-6. (Transformation ratio map from the Play Fairway Atlas, OETR, 2011)
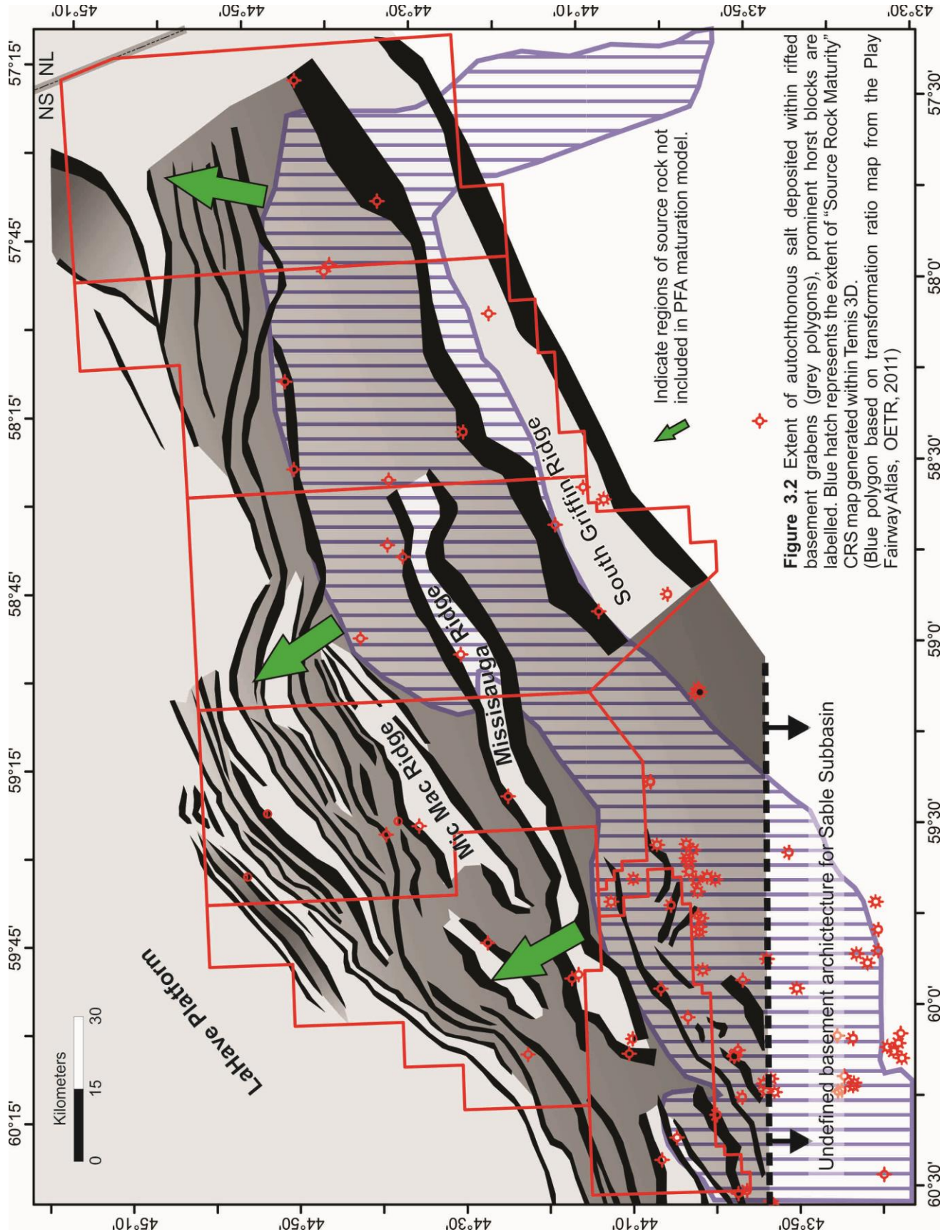
Figure 3.2 Extent of autochthonous salt deposited within rifted basement grabens (grey polygons), prominent horst blocks are labelled. Blue hatch represents the extent of "Source Rock Maturity" CRS map generated within Temis 3D. (Blue polygon based on transformation ratio map from the Play Fairway Atlas, OETR, 2011)

Figure 3.3 Transformation ratio map of a Callovian source rock, overlain by Parcels 1-6. (Transformation ratio map from the Play Fairway Atlas, OETR, 2011)

Figure 5.1: Known and conceptual plays, and petroleum systems elements in the Abenaki Subbasin based on interpretation of
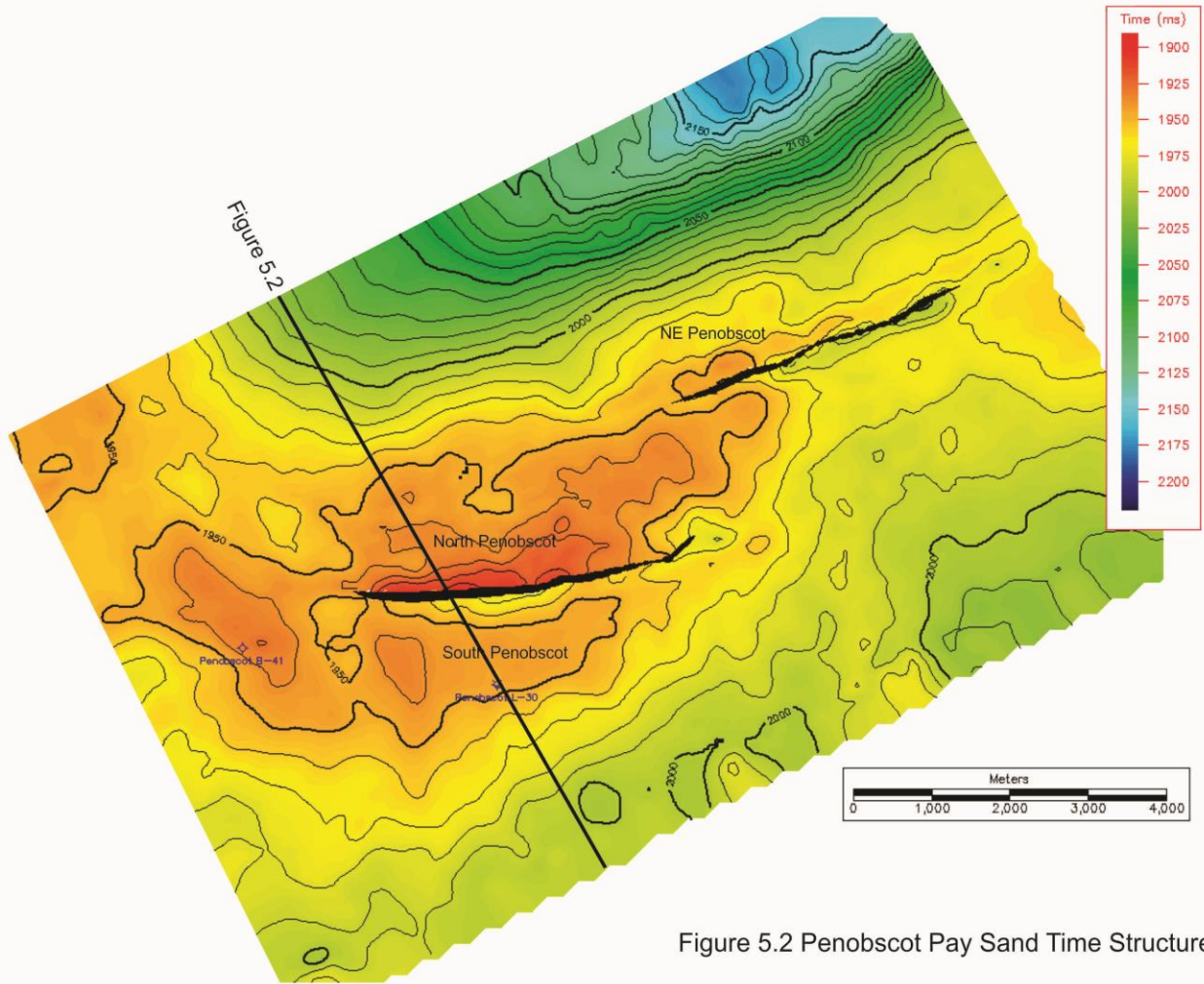
Figure 5.2 Penobscot Pay Sand Time Structure Map
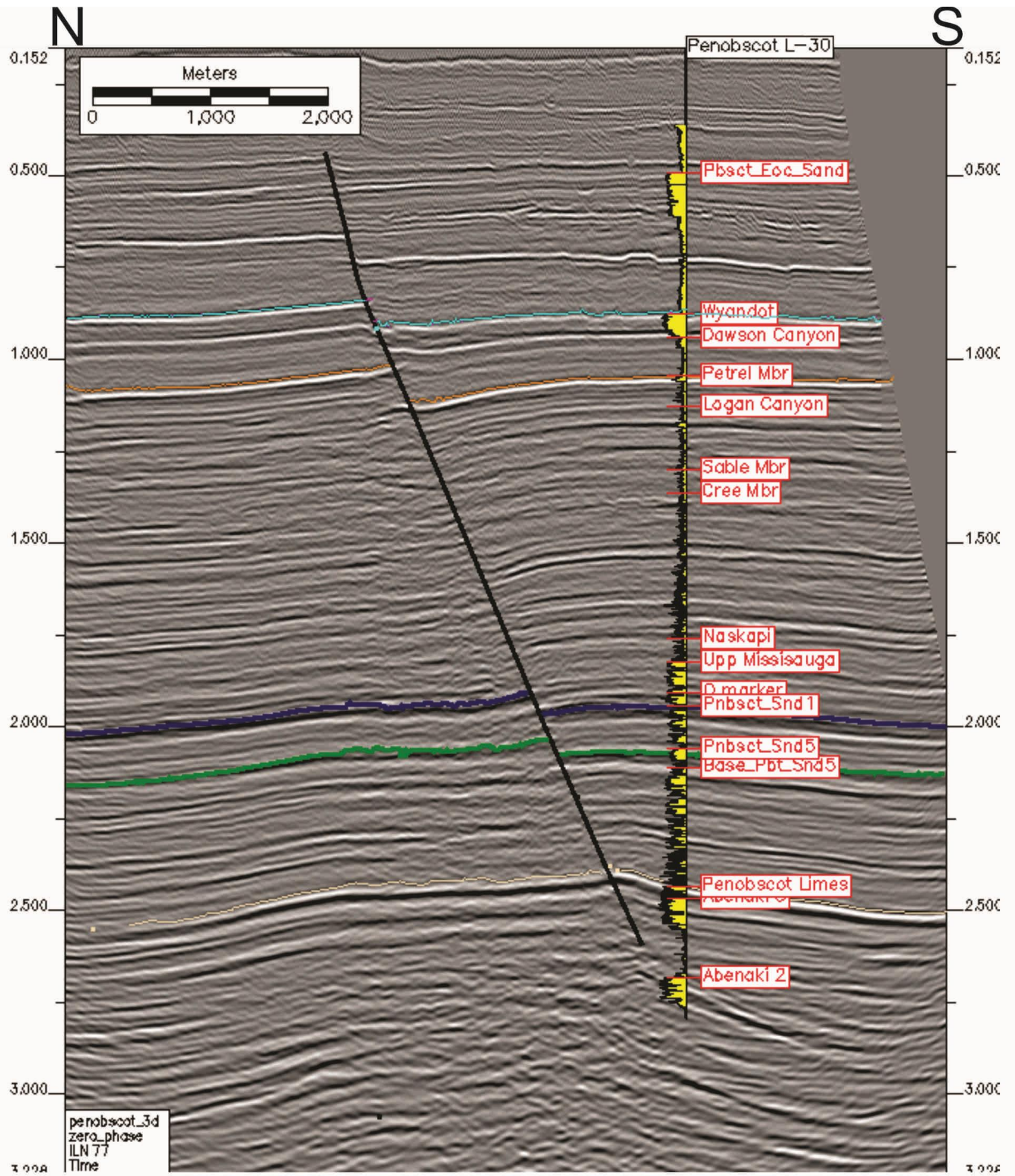
Figure 5.3 Pen...
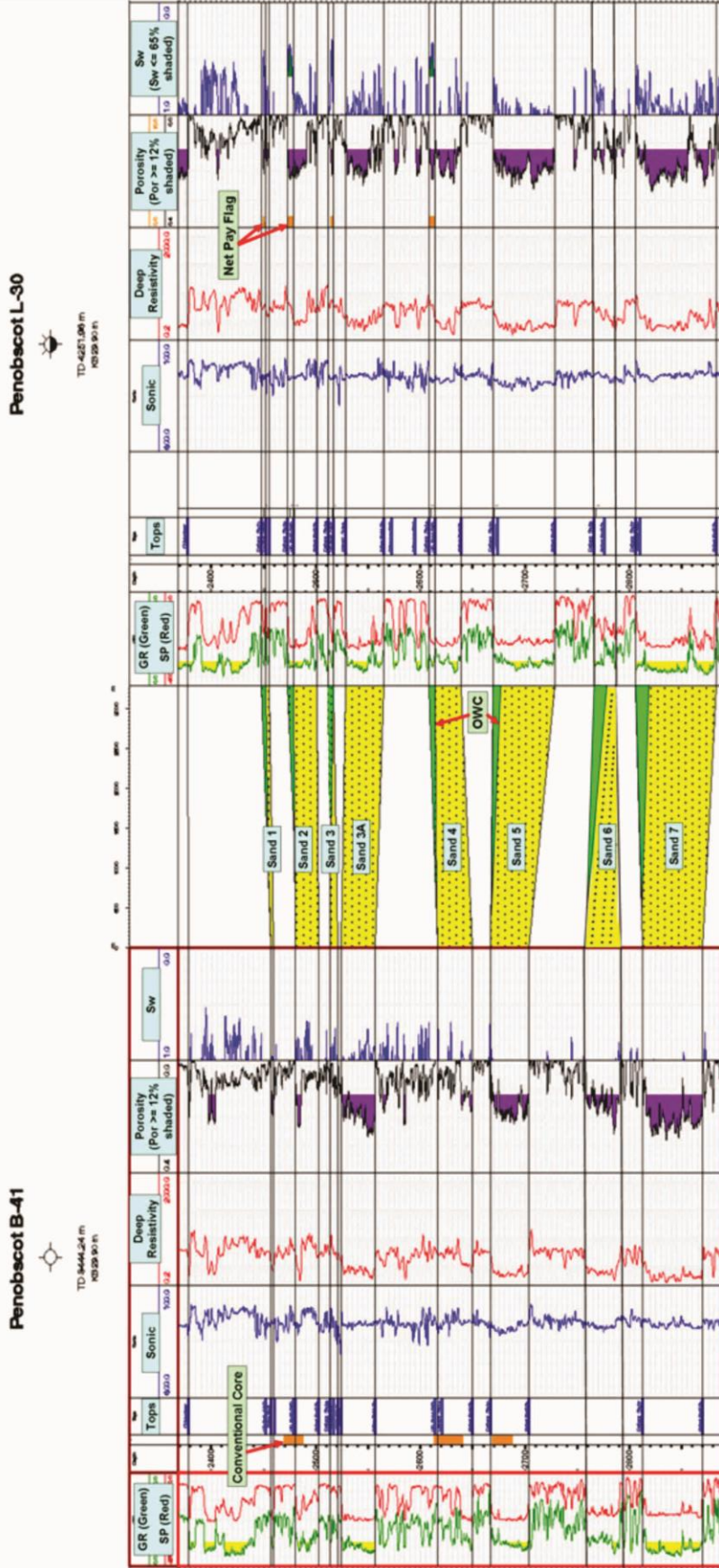
Figure 5.4 Penobscot Cross Section

Figure 5.5 Seismic Line Locations on J150 Time Map
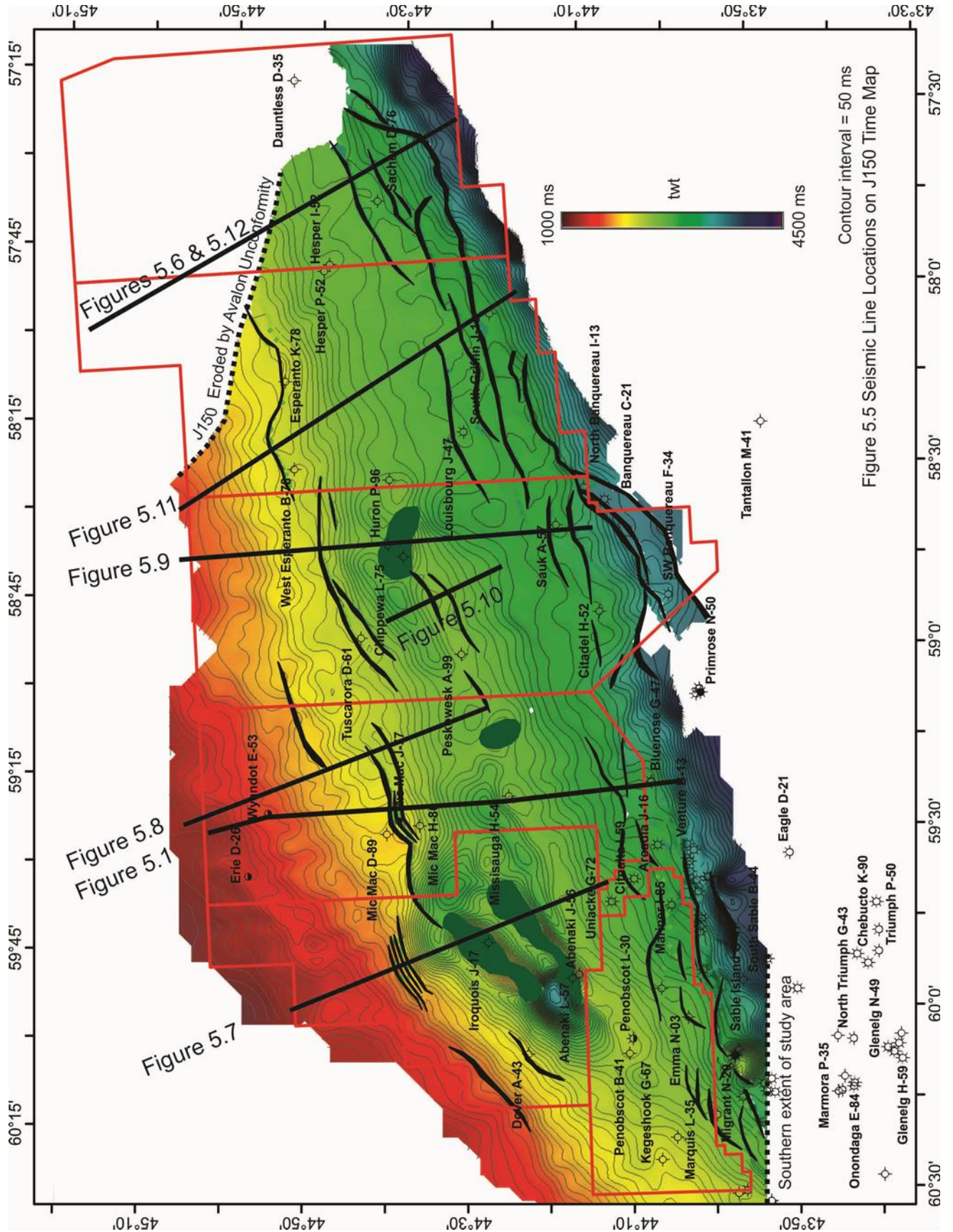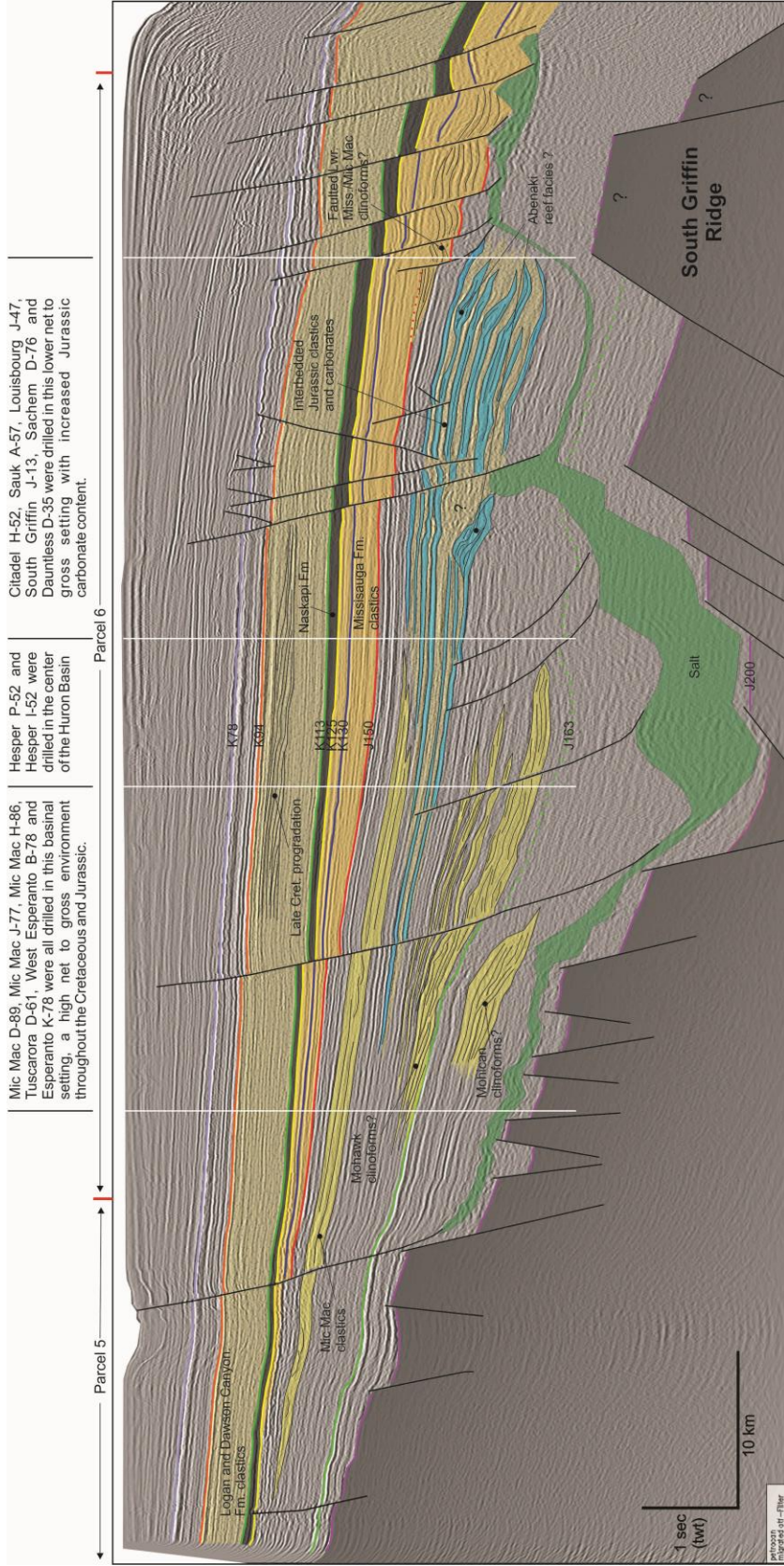
Figure 5.6. Seismic line through Parcels 5 and 6. Schematic lithologic interpretations based on offline well penetrations and seismic stratigraphy. For an uninterpreted version of this seismic line see Figure 5.12. Line location is shown in Figure 5.5.
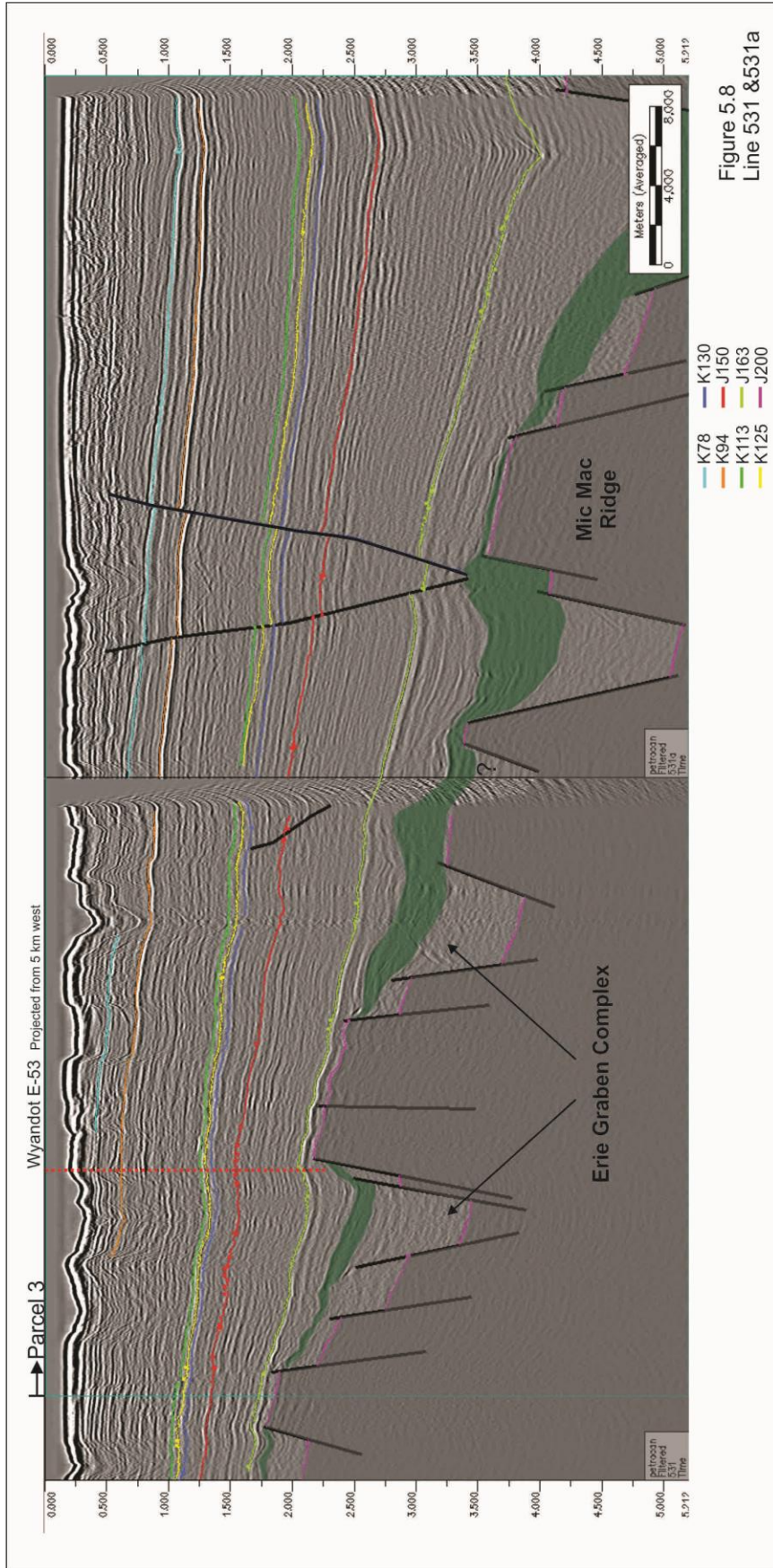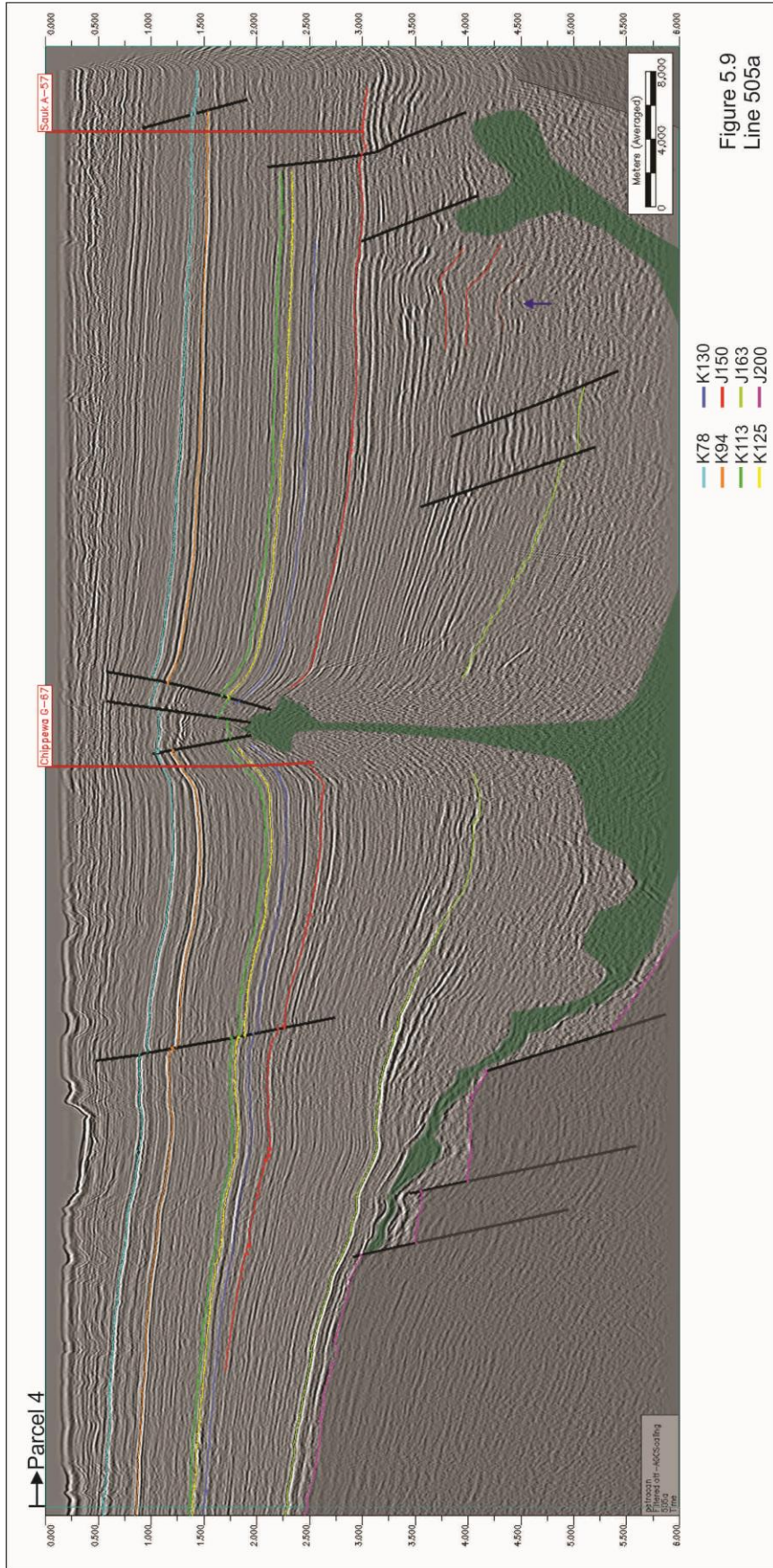
Figure 5.7
Line 82-619 & 619a
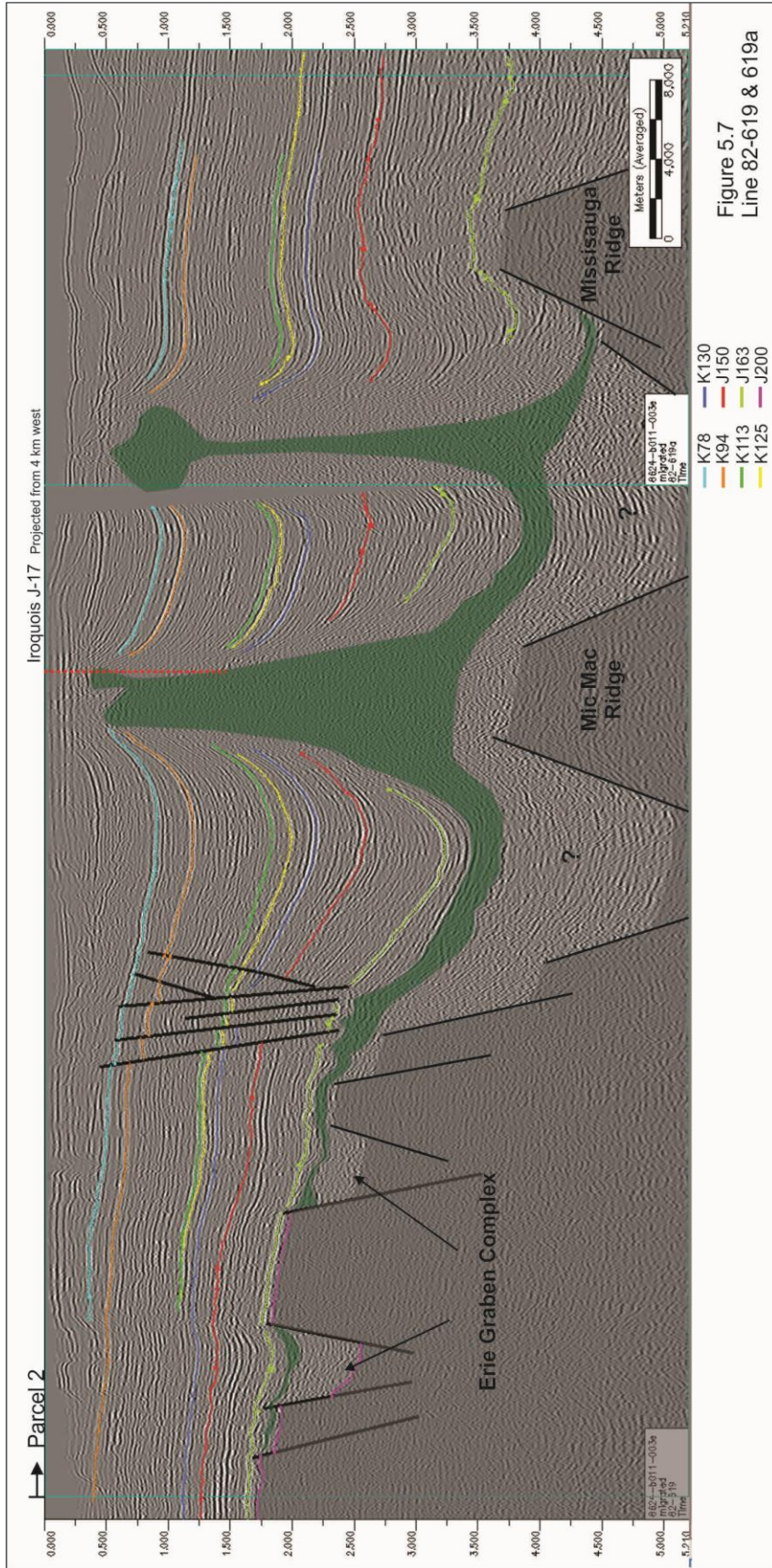
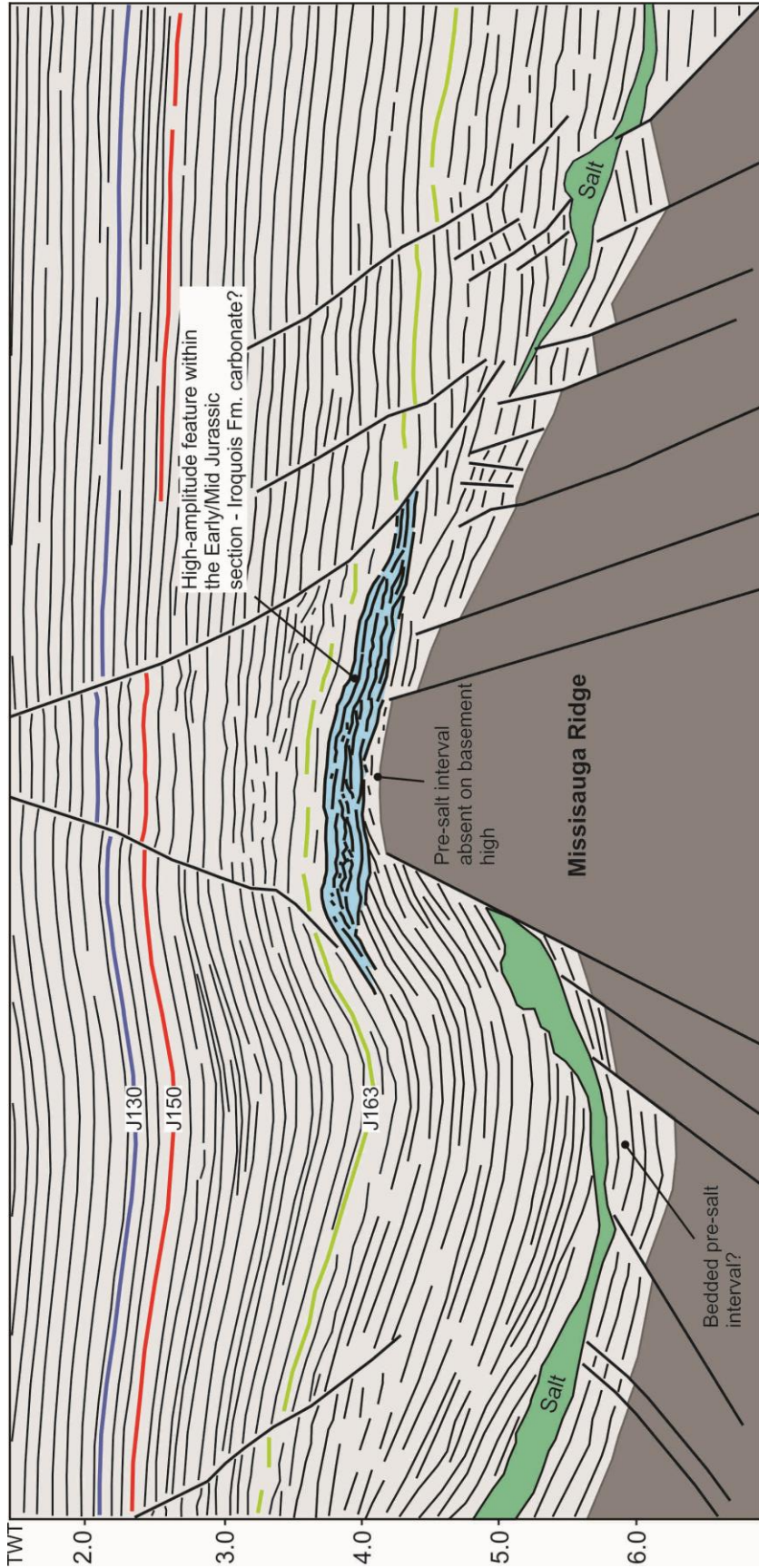Figure 5.8
Line 531 &531a

Figure 5.9
Line 505a

Figure 5.10. Line drawing of a seismic profile within Parcel 4 highlighting a potential Early/Middle Jurassic carbonate buildup over the Mississauga Ridge.
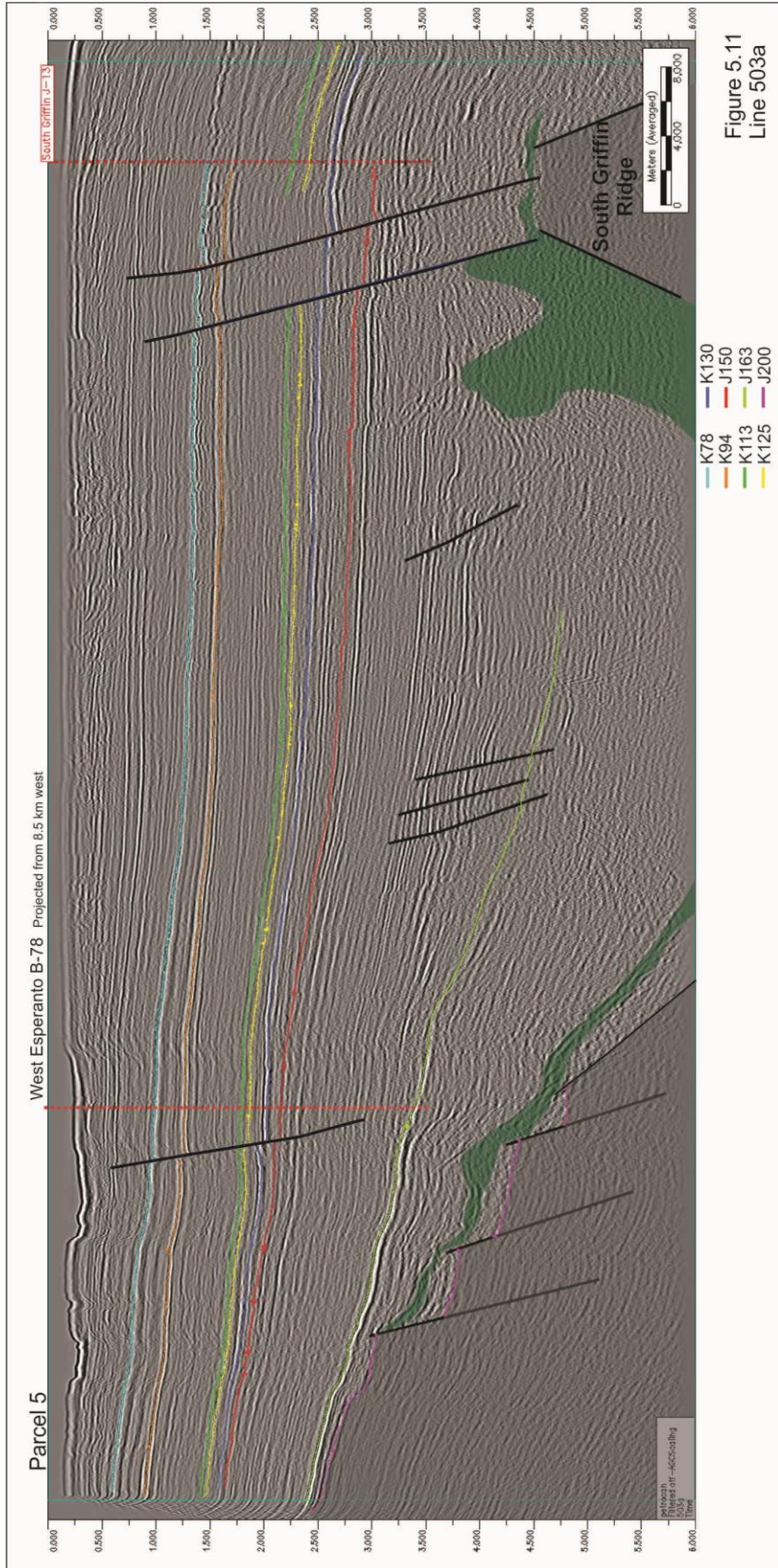
Figure 5.11
Line 503a

Figure 5.12
Line 4055

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