Canada-Nova Scotia Offshore Petroleum Board

NOVA SCOTIA DEEPWATER POST-DRILL ANALYSIS 1982-2004

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THE CANADA-NOVA SCOTIA OFFSHORE PETROLEUM BOARD

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EXECUTIVE SUMMARY

Between 2002 and 2004 industry drilled seven deepwater wells on the Scotian Slope with one gas discovery (Annapolis), one gas show (Newburn) and four dry wells (Balvenie, Crimson, Weymouth and Torbrook). The seventh well, Annapolis B-24, was a precursor to the discovery well that was abandoned due to a shallow gas kick. Four previous wells were drilled between 1982-1986 that were dry and abandoned, and are included in this analysis (Shubenacadie, Shelburne, Evangeline and Tantallon).

Whether successful or not, all wells provide important calibration for the relationship between seismic and geology. The focus of this study was to undertake a post-drill analysis of all ten deepwater wells by compiling all available data and information, studying and interpreting these data, and drawing conclusions related to the following broad headings:

- Pre-Drill Objectives
- Post-Drill Results
- Geological Implications
- Operations and Costs
- Impact on 2002 CNSOPB Resource Assessment

The Scotian Basin is a passive margin and has proven petroleum systems with past production from the Cohasset-Panuke oil fields, ongoing gas production from the Sable Project and the undeveloped Deep Panuke gas field, all on the shallow Scotian Shelf. Recently, exploration focus shifted to the deepwater Scotian Slope because of the impressive hydrocarbon discoveries and high success rates in deepwater of other circum-Atlantic basins such as the Gulf of Mexico, offshore Brazil and West Africa, and recently Northwest Africa (Mauritania).

The Scotian Slope is 850km long and has an area of 80,000km^2 containing only the aforementioned ten wells that are either clustered or widely distributed within a long and narrow belt. The degree of basin evaluation for these wells as determined by geographic location, successions penetrated, total depth and thickness of target section cannot be considered comprehensive.

Exploration in the deepwater habitat requires high quality 2D and 3D seismic data and the application of sophisticated processing and interpretation. The reservoir targets are deepwater submarine fan sands that are transported from the shelf and deposited on the slope coeval with major changes in relative sea-level (lowstands). This process can create erosional submarine canyons which act as conduits for the transport of vast quantities of sediments.

The analysis of seismic character attributes and the application of seismic sequence stratigraphy has been proven successful in the detection of reservoirs in the Tertiary sediments of the Gulf of Mexico, offshore Brazil, West Africa and Mauritania. Thus far, the application of these techniques has met with little success in the older Cretaceous age section offshore Nova Scotia.

The cost of recent deepwater drilling off Nova Scotia was exacerbated by equipment difficulties and incorrect prediction of the geopressure regime. However, as Marathon demonstrated, after their Annapolis well, the learning curve was steep and costs for their second well at Crimson were significantly reduced.

Discovered gas in the Annapolis and Newburn wells confirms an active slope petroleum system. Annapolis found a cumulative 27m of generally thin gas-bearing sands, and Newburn encountered several thin (2-3m) gas-bearing sands. Furthermore, many of the gas-bearing sands were encountered unexpectedly below 5000m with average porosities from 14-19% which expands the zone of prospectivity. A significant insight, based on paleoenvironmental interpretations from available well biostratigraphic data, indicates that the presumed Cretaceous age deep water sediments were actually deposited in the shallow waters of the outer shelf and upper slope. This knowledge will have a profound, but ultimately positive impact on future exploration.

In 2002 the Board completed a deepwater resource assessment prior to results from the recent seven wells (Kidston et al., 2002). The assessment consisted of 12 geostatistical computation runs to capture the diversity of play areas and play types. The recent drilling results affect three of those twelve runs by altering input parameters particularly regarding the presence and quality of reservoir.

The impact of the recent deepwater well results on the undiscovered gas and oil potential is minimal. The comparison is shown in the following table, with gas potential reduced only by several Tcf and oil potential by fractions of billions of barrels. The Scotian Slope thus remains a virtually unexplored deep water frontier basin with a confirmed petroleum system and the potential for significant hydrocarbon discoveries.

Assessment	Potential GAS (Tcf)	Potential OIL (BB)
2002 Report	**15 – 41**	**1.7 – 4.7**
2007 Revision	**12 – 39**	**1.3 – 4.5**

1. INTRODUCTION

The deepwater slope offshore Nova Scotia extends from the shelf break at 200m to almost 4000m (Figures 1 & 4). The slope area under study is dictated by the depositional limit of the Argo salt and industry seismic coverage generally within the 3000 to 4000m range. A highly exaggerated three-dimensional perspective of the slope is shown in Figure 2.

This area was the subject of the Board's 2002 report; "Offshore Hydrocarbon Potential Deepwater Slope" (Kidston et al., 2002). The study included a basin analysis and a numerical assessment of the hydrocarbon potential for gas and oil.

Since that report, seven new deepwater wells were drilled between 2002 and 2004 (one of these an early abandonment and thus not a valid test). This report examines the drilling results of the remaining six wells and their impact on the 2002 assessment.

In addition to the evaluation of the seven recent wells, four wells drilled in the mid-1980s (*) are included in this study (Enclosure A). Hence, the areal distribution of the eleven wells is:

- Central Upper Slope — Newburn, Balvenie, Annapolis (2), Crimson
- Western Upper Slope — Shelburne*, Torbrook, Shubenacadie*
- Central Salt Canopy Complex — Weymouth
- Salt Withdrawal Area — Tantallon*
- Sable Delta Fringe — Evangeline*

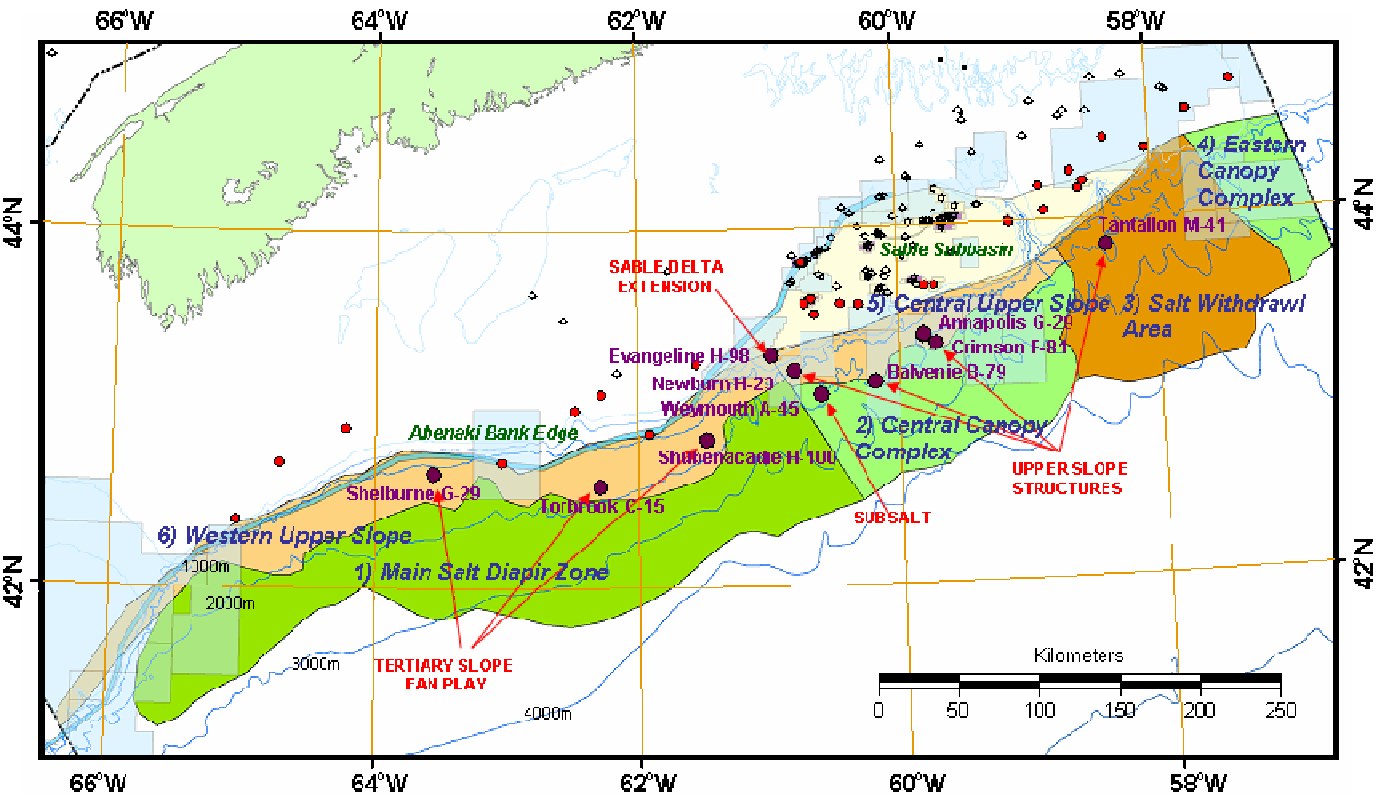


Figure 1. Deepwater location map. The shaded areas represent different geological provinces within the deepwater slope. The extents of the Jurassic carbonate bank and the Sable Sub-basin are also shown. Purple annotated wells were the focus of this study. The type of play tested by each well is shown in red. Transparent blue polygons show the 2006 land interests.

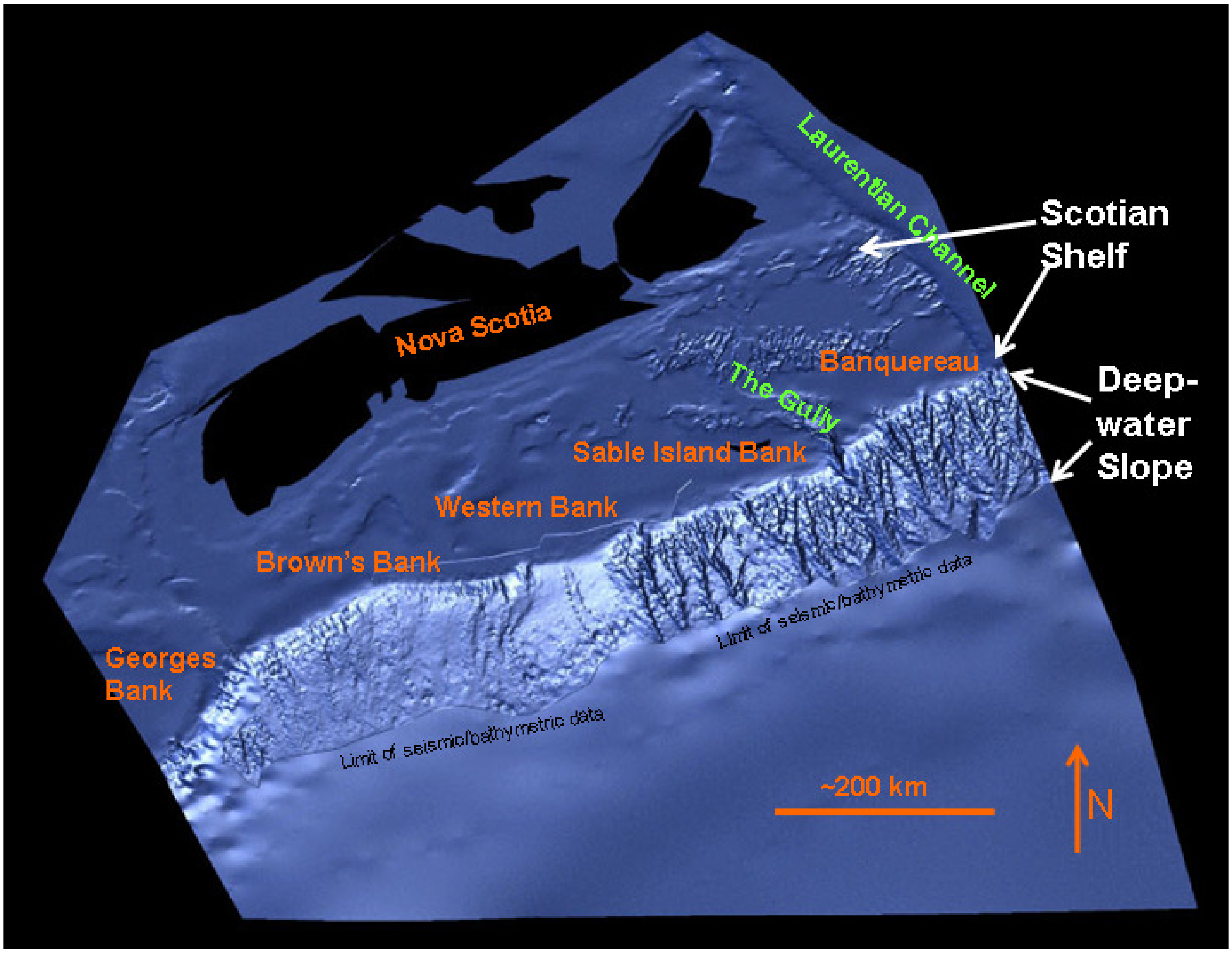


Figure 2. 3-D image of the bathymetry and major features offshore Nova Scotia.

Except for Annapolis G-24 (gas well) and Newburn H-23 (gas show) the remaining nine wells were all dry and abandoned. The precursor Annapolis B-24 well was abandoned after a shallow gas kick and the rig moved 900m northwest to the G-24 location. Regardless of success, all wells provide varying degrees of ground truth which offers the necessary calibration between seismic and geology. The focus of this study is to complete a post-drill analysis of each of the wells by compiling and analyzing data, making observations and interpretations, and drawing conclusions related to the following broad headings:

- Pre-Drill Objectives
- Post-Drill Results
- Geological Implications
- Operations and Costs
- Impact on Assessment

In addition to the above, this report will include some background material on the history, definitions and classifications of submarine fans, as well as industry concepts and examples from analogue basins.

Also included are examples from the Scotian Slope of various depositional configurations such as mini-basins, turtle structures and canyon/fan systems that have not yet been drilled and merit further investigation and drilling.

The final and arguably the most important step in this report was a revision to the deepwater slope numerical assessment based on the drilling results of the wells evaluated.

2. Overview of Deepwater Drilling Offshore Nova Scotia

The first four deepwater wells were drilled in the mid-1980s, and the later seven were drilled between 2002 and 2004 (Figures 1 & 3). Clarification is required as to the definition of a "deepwater" well. Generally, a deepwater well is drilled beyond the shallow water shelf in water depths greater than 200m. However, sometimes the subsurface targets also become a factor. Figure 4 is a standard deepwater profile to illustrate the position of recent drilling operations that occurred within the present-day upper bathyal environment (upper slope). The depositional setting and paleoenvironment of reservoir targets are an important factor and will be addressed in the subsequent well discussions.

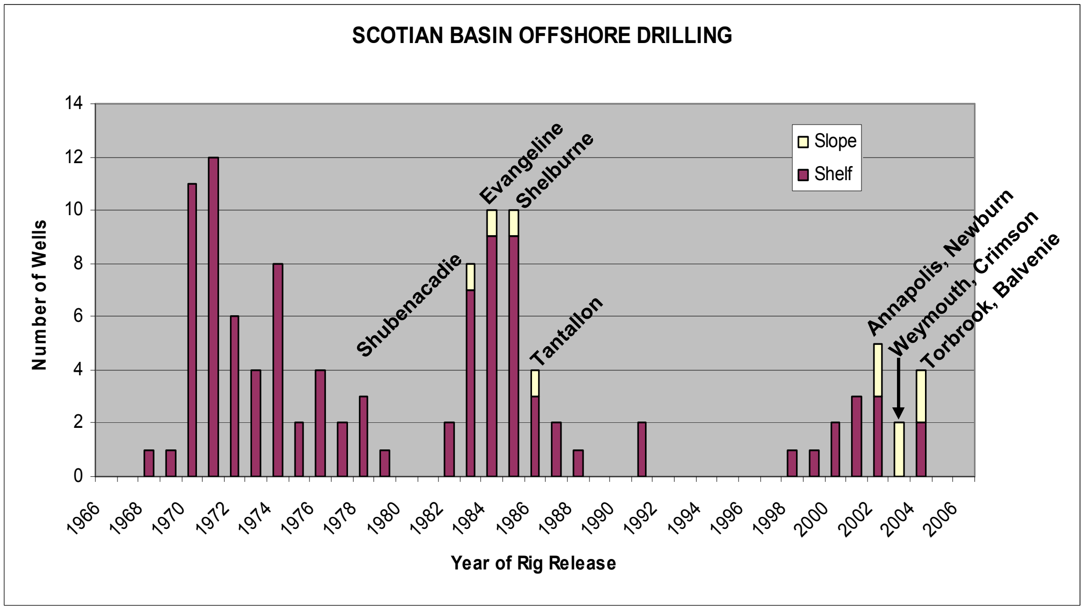


Figure 3. Scotian Basin offshore drilling (Nova Scotia).

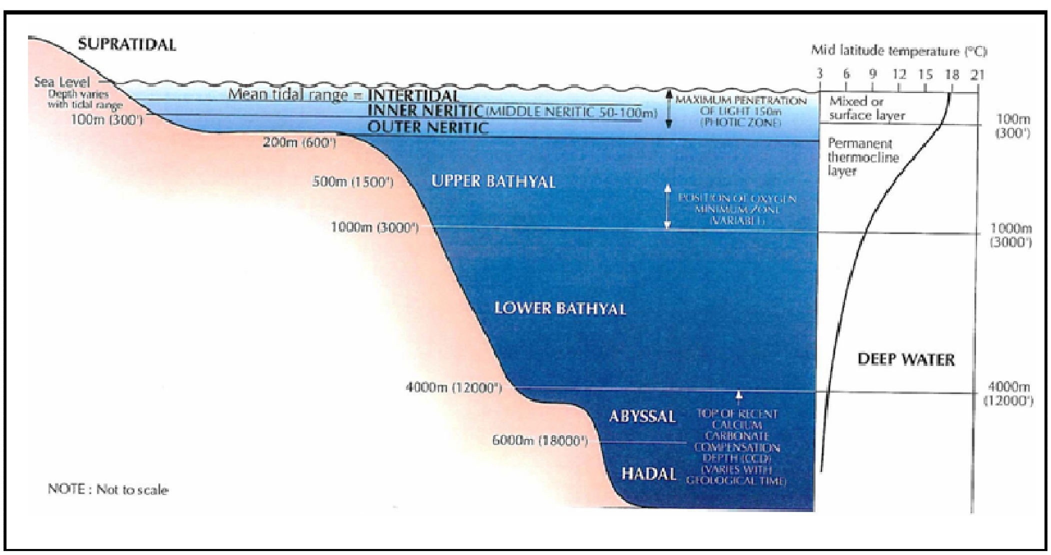


Figure 4. Marine benthic environments (Robertson Research, various reports).

The ten wells of this study (excluding the shallow Annapolis B-24 abandonment) include the Evangeline H-98 well although it was drilled on the present-day shelf in a water depth of 174m. Evangeline lies between the outermost Sable paleodelta gas field wells such as Alma, Glenelg and Triumph and the deepwater Newburn H-23 well, thus it is required as a control well. Conversely, two wells that were drilled in the present-day deepwater, Albatross B-13 (1341m) and Acadia K-52 (866m), were not included because their targets were the Jurassic carbonate bank edge, not paleo-deepwater submarine fans. These two wells were included in the Board's report on the Abenaki Formation (Kidston et al., 2004).

The subject wells are situated along the upper continental slope in water depths between 980 and 2092m (except for Evangeline H-98 as noted above). The distance between Shelburne G-29 in the southwest to Tantallon M-41 in the northeast is 450 kilometers. The drilled section; i.e., the sedimentary section below the seafloor, ranges from 1925m at Torbrook C-15 to 5090m at Newburn H-23 (Table 1). Of paramount interest is the amount of pre-Tertiary (i.e. Cretaceous and Jurassic) stratigraphy penetrated basinward of the Sable area since this is where potential hydrocarbons are believed to occur. The Cretaceous section drilled ranges from 1210m at Balvenie B-79 to 3200m at Newburn H-23. The thin Cretaceous sections at Shubenacadie H-100 and Torbrook C-15 are because their primary targets were submarine fans within the Tertiary succession. Jurassic age strata have yet to be penetrated in this setting.

The Scotian Basin stratigraphic chart (Figure 5) is based on the detailed work by MacLean and Wade (1990) and simplified in the Board's 2002 report (Kidston et al., 2002). The deepwater drilling targets were mostly lowstand submarine fans coeval with sand-prone sequences on the shelf. It is important to note that allochthonous (mobile) salt has, in places, almost reaches the present-day sea floor, thereby limiting the objective stratigraphic sections.

Period	Well	Water Depth (m)	FTD (m)	Drilled Section (m)	Cretaceous Section (m)
Initial Wells					
1982-83	Shell Shubenacadie H-100	1471	4200	2729	416
1984	Husky/BVI Evangeline H-98	174	5044	4870	3188
1985	PEX Shelburne G-29	1154	4005	2851	1400
1986	Shell Tantallon M-41	1566	5602	4036	2552
Recent Wells					
2001-02	Marathon Annapolis B-24	1737	3496	1759	0
2001-02	Marathon Annapolis G-24	1752	6182	4430	2728
2002	Chevron Newburn H-23	980	6070	5090	3219
2002-03	EnCana Torbrook C-15	1675	3600	1925	0
2003	Imperial Balvenie B-79	1803	4750	2947	1210
2003-04	EnCana Weymouth A-45	1690	6520	4830	2128
2004	Marathon Crimson F-81	2092	6676	4584	3048

Table 1. Deepwater Well Statistics 1982-2004.

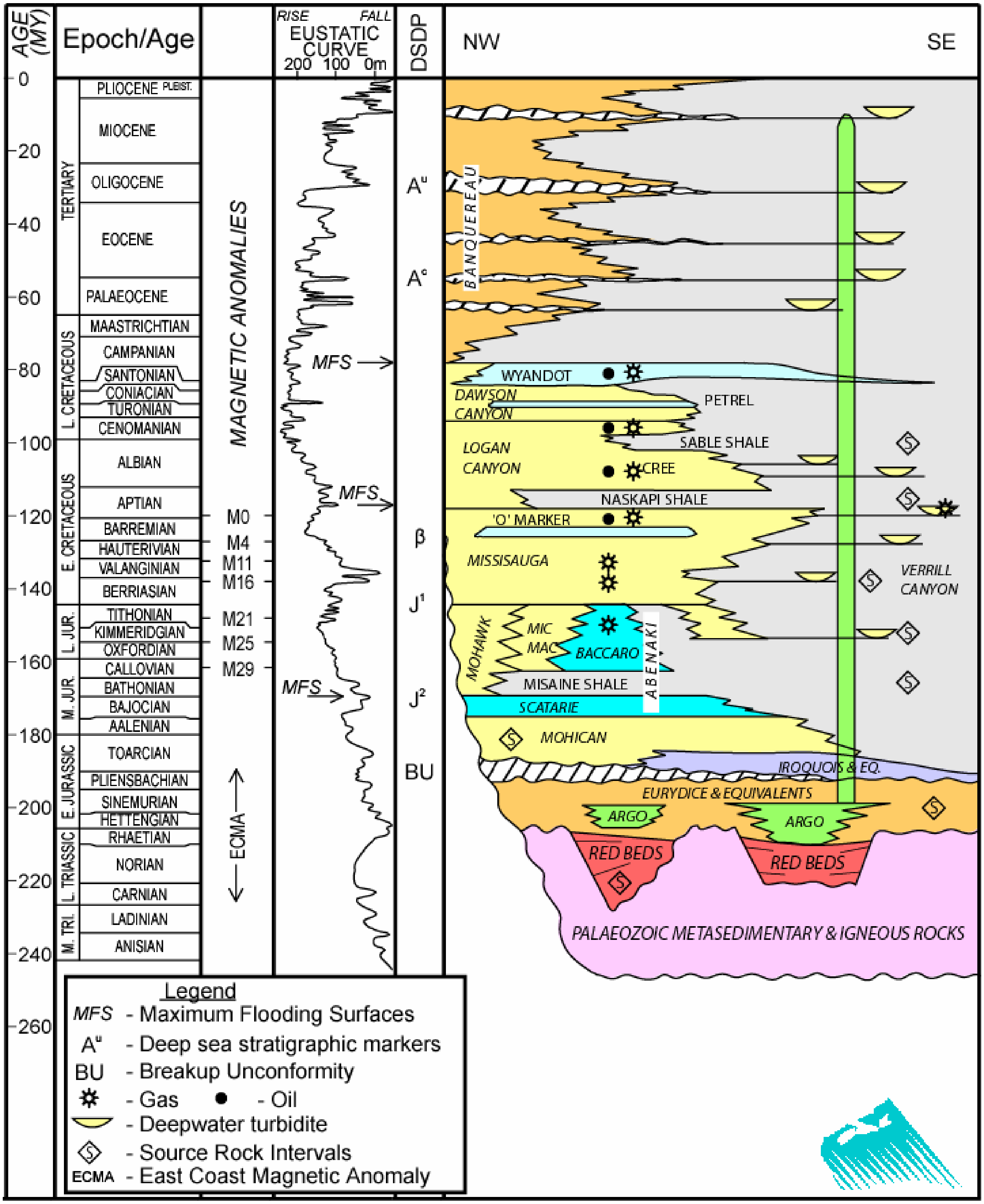


Figure 5. Stratigraphic column for the Scotian Shelf. Stratigraphy modified from Wade (1993, 1995). Eustatic curve from Haq et al (1987). Time scale from Palmer and Geismann (1999).

2.1 Initial Period: 1982 – 1987

The early exploration phase saw the first use of semi-submersible drilling rigs offshore Nova Scotia, the SEDCO 709 and 710 under contract to Shell and PetroCanada respectively. The early wells were designed to test two play types: Shelburne and Shubenacadie targeted interpreted look-alikes to the then successful North Sea stratigraphic submarine turbidite fan play, while Evangeline and Tantallon tested the seaward limit of the Sable paleodelta sands and/or any submarine fans developed within large anticlinal structures.

2.2 Recent Period: 2001 – 2004

The latest round of drilling followed on the heels of enormous successes in other circum-Atlantic passive margin basins off West Africa, offshore Brazil and the Gulf of Mexico. Armed with interpretations based on the large regional 2D surveys by TGS-NOPEC and Western-Geco, industry quickly leased the entire deepwater offshore Nova Scotia region accompanied with work bonuses totaling approximately C$1.5 billion. Acreage was high-graded and 3D surveys were acquired over prospective anomalies.

Operators soon had partners who shared in the efforts and results. EnCana, following their successful Deep Panuke gas discovery (Upper Jurassic carbonate margin, Abenaki Formation), turned their attention to the deepwater, and tested two very different play types: a Tertiary submarine fan play (Torbrook) and a Cretaceous subsalt play (Weymouth). Marathon, Chevron and Imperial drilled structural features in front of the productive Sable Delta. Only Marathon's Annapolis G-24 well encountered reservoirs with appreciable volumes of gas.

3. Deepwater Submarine Fans

Deepwater submarine fans have become prolific producers around the world (Pettingill and Weimer, 2001). Until 1960, petroleum exploration ended at the edge of the continental shelf in 200m of water. Once the existence and potential of submarine fans was realized, it was only a matter of time until explorers stepped seaward into deeper water as they did in the Gulf of Mexico and were rewarded with ever-increasing successes. Since then, explorers have looked at every deepwater margin around the world, especially in the circum-Atlantic region, and have had tremendous successes offshore West Africa, Brazil, Norway, Australia and Mauritania.

To facilitate understanding of this technical evaluation, working knowledge of submarine fans and deepwater processes and technical terminology is required. An appreciation of exploration concepts and their evolution is also necessary, as well as industry's current status in the recognition and prediction of these targets. Exploration for submarine fans is seismic-based and very much dependent on 3D imaging and the application of seismic sequence stratigraphic analysis.

3.1 History

Unlike fluvial and deltaic systems and processes that have modern surface expressions and can be easily observed and studied, deepwater depositional systems are difficult to study. However, once concepts were understood and embraced, knowledge quickly evolved. The history of deepwater depositional systems is well described in Reading and Richards (1994) and is summarized below:

- 1929 - Grand Banks Earthquake, sequential breakage of submarine cables.
- 1950 - Discovery of turbidity currents as carriers of sands to the abyssal plains of the present North Atlantic.
- 1960 – Recognition of ancient deep-water depositional systems in outcrops globally.
- 1978 - A single feeder system fan model was proposed by Walker.
- 1980 - Nilsen (1980) expanded this to two models, a fine-grain delta-fed fan and a coarse-grain canyon-fed fan.
- 1988 - Shanmugam and Moiola (1988) argued for systems dominated by submarine fans that by definition were channel and lobe complexes caused by sediment gravity flows in the deep sea environment beyond the shelf.
- 1994 - Reading and Richards (1994) expanded previous classifications to multiple models with factors of grain-size, feeder system, sea level, sediment supply, tectonics (including salt and shale), etc.

The spectrum of underwater mass wasting processes and products from creep to turbidity flow is presented by Martinsen (2003) and shown in Figure 6. The ability to identify these features on seismic is the challenge, not in recent examples nor even the Tertiary but in older rocks such as the Cretaceous and Upper Jurassic successions deposited on the Scotian Slope. The examples from the Scotian Slope demonstrate this challenge. The interpreted Torbrook C-15 Tertiary submarine fan is an excellent example of an attempt at prediction (see Section 5.7). A list of definitions for mass wasting processes and other terms is presented in the Glossary at the end of this report.

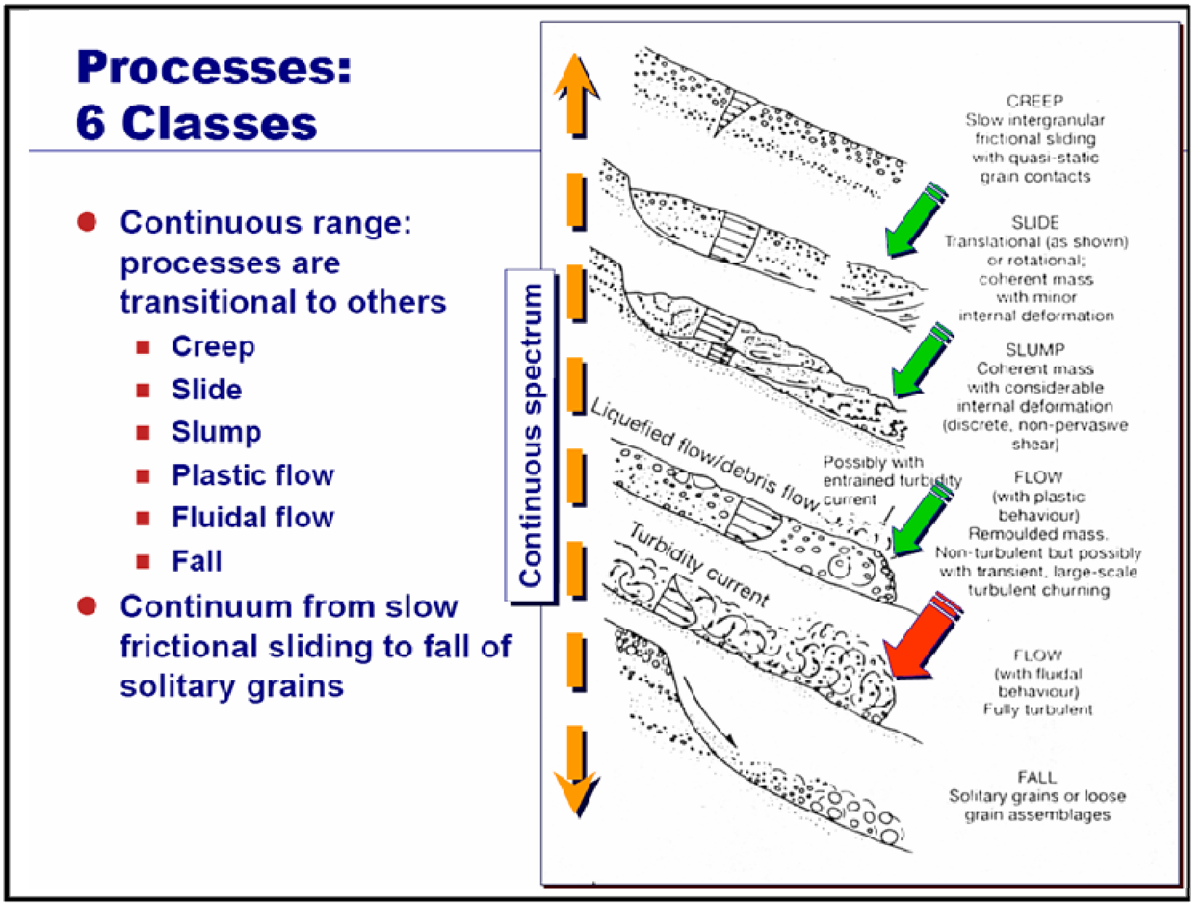


Figure 6. Mass wasting continuum (Martinsen, 2003).

3.2 Classification

The classification by Reading and Richards (1994) for deepwater basin margins was based on grain size and feeder system classification. Figure 7 displays all 12 of their models from point and multi-sourced fans to line-sourced slopes relative to mud, sand/mud, sand or gravel. For the Scotian Basin, the point-source and line-source models for mud, mud/sand and sand-rich fan systems appear to be the most appropriate based on current knowledge.

3.2.1 Mud-Rich Point and Line Sourced

The mud-rich point and linear sourced slopes are shown in Figure 8. Present-day mud-rich deep-sea fans such as the Bengal, Indus, Amazon and Mississippi cover enormous areas with gentle gradients fed by major fluvial/deltaic systems (point-source). The Laurentian Fan between Nova Scotia and Newfoundland is the exception having been fed by glaciomarine sediments and deposited over the past 2-3 million years. Potential reservoir facies in these fans may occur as restricted channel sands and thin but widespread levee margin sands. The magnitude of the fans makes them difficult to recognize in exposures in ancient basins. Reading and Richards (1994) list only one little-known ancient example, whereas recent examples, as noted previously, abound.

The linear source mud-rich slope has a relative absence of turbidites and so slumping becomes the major process. Sands do not occur on a typical mud-rich slope either because of sedimentary starvation or restriction of coarser grained clastics (sands) to the shelf. This may be a concern along the western slope area of the Scotian margin where ancient fluvial/deltaic systems have not yet been identified due to limited well and seismic data and current interpretations of sediment-starved conditions during the Cretaceous.

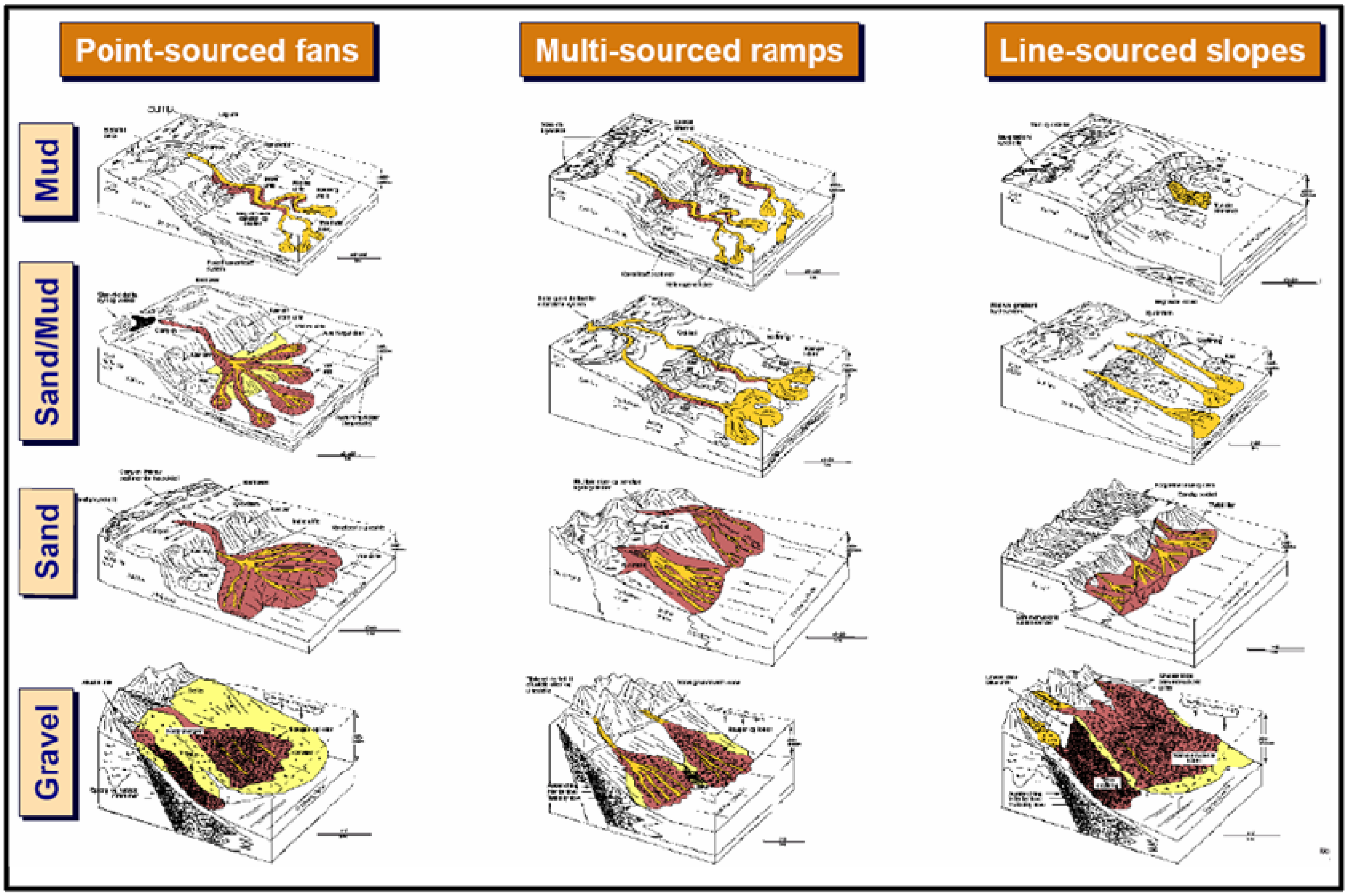


Figure 7. Turbidite system classification. From Reading and Richards (1994).

3.2.2 Mud/Sand-Rich Point and Line Sourced

The mud/sand-rich point source systems (Figure 9) are moderate in size with a typical 30-70% sand percentage for the entire system. The systems are fed either from a moderately sized mixed-load delta, a coastline or an active sediment-rich shelf cut by a canyon. Typical modern examples are the recent fans off California in a tectonically active basin margin with narrow continental shelf. Ancient examples are known from the North Sea region.

The linear source mud/sand-rich slope aprons are associated with low-gradient basin passive margins with development of submarine slides and slumps along the slope. Repeated mass wasting can create topography to catch turbid flows and will exhume relict coarse-grained sediments.

3.2.3 Sand-Rich Point and Line Sourced

Sand-rich point sourced submarine fans contain more than 70% sand and are moderate in size (about 5-10km) and radial rather than lobate in form (Figure 10). The linear sourced sand-rich slope can form a complex linear sheet that does not extend far into the basin. Reading and Richards (1994) suggest offshore Nova Scotia as being a likely example where the coastal plain reached close to the shelf edge during periods of lower sea level.

Pseudo-log responses created from outcrop studies and modeling illustrate the reservoir architecture of mud-rich and mud/sand-rich systems within channel-levee complexes (Figure 11). Construction of such profiles from local drilling results may assist in locating the position within a fan system. This is very important for any follow-up drilling subsequent to an initial well where a fan system has been penetrated and identified.

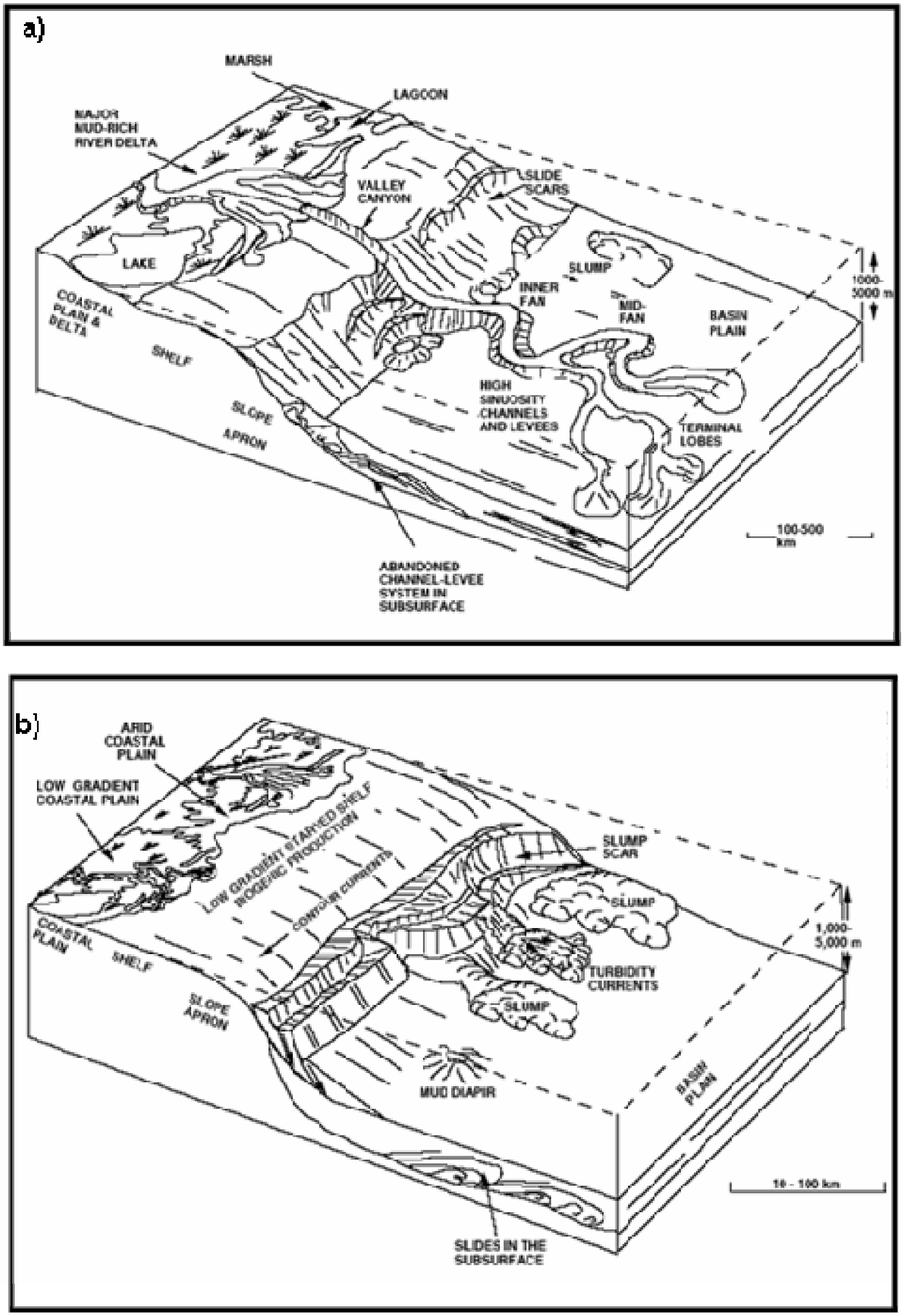


Figure 8. Mud-rich submarine fan systems (Reading and Richards, 1994).
a) Point source system; b) Linear source system.

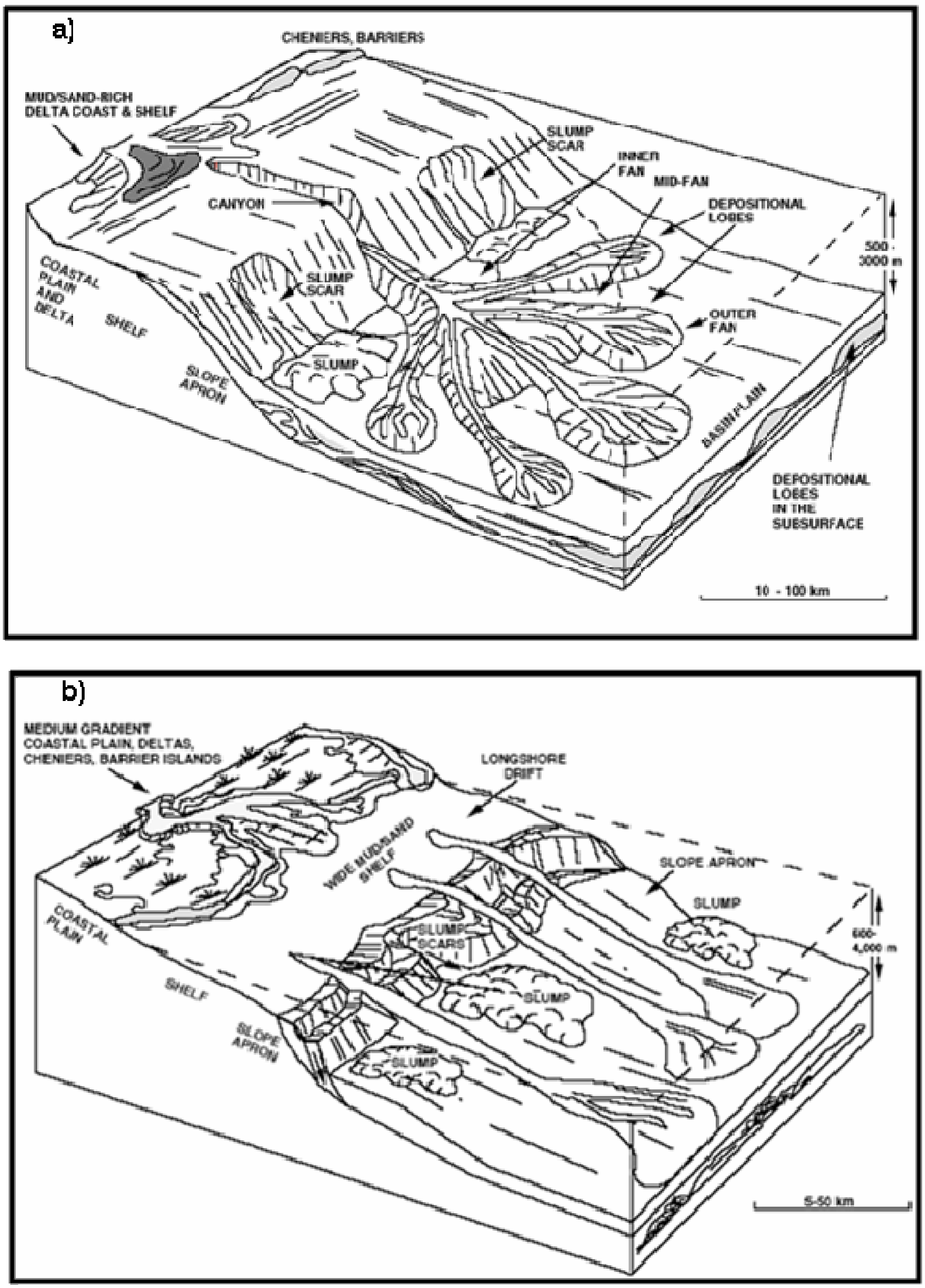


Figure 9. Mud/sand-rich submarine fan systems (Reading and Richards, 1994).
a) Point source system; b) Linear source system.

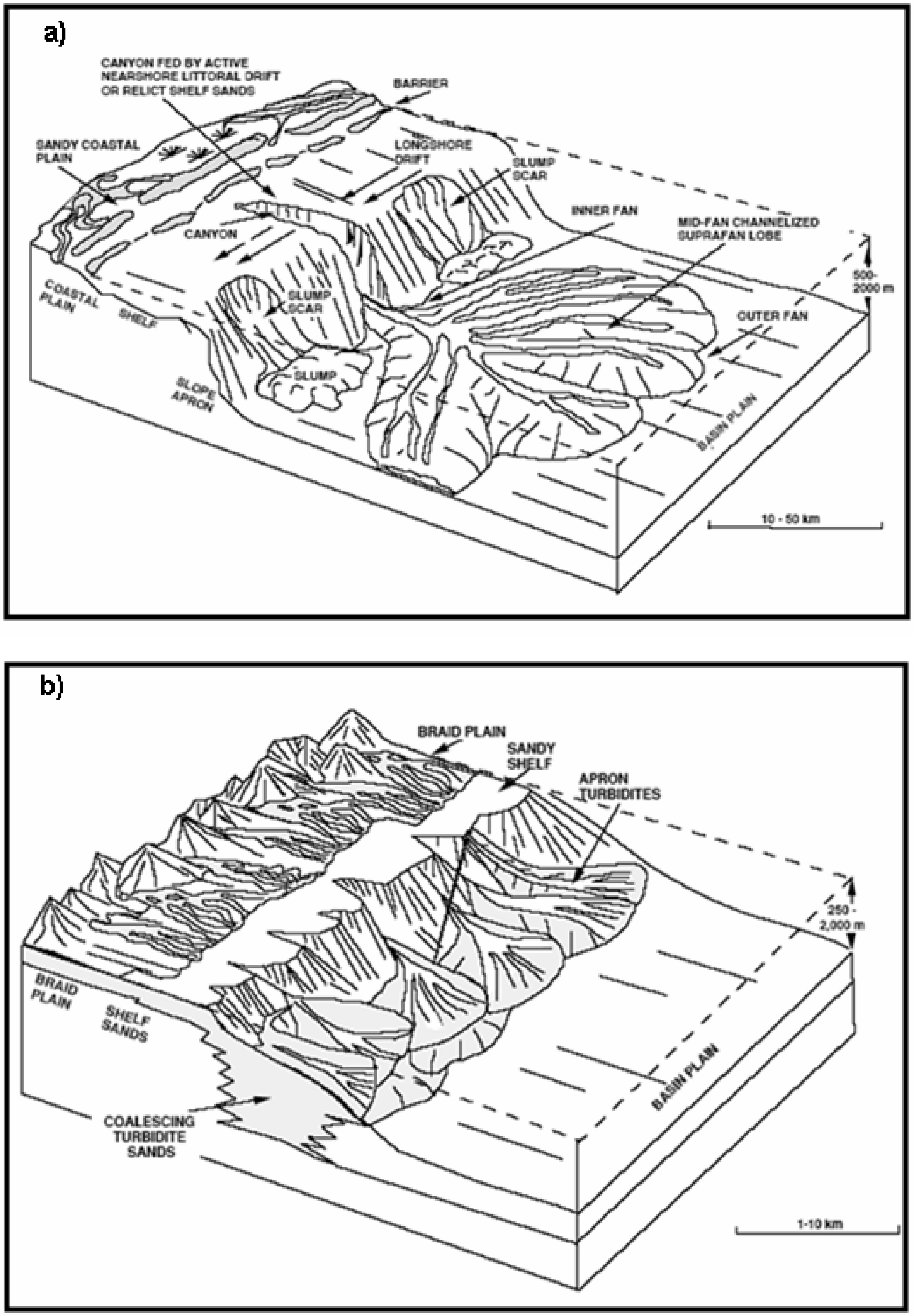


Figure 10. Sand-rich submarine fan systems (Reading and Richards, 1994).
a) Point source system; b) Linear source system.

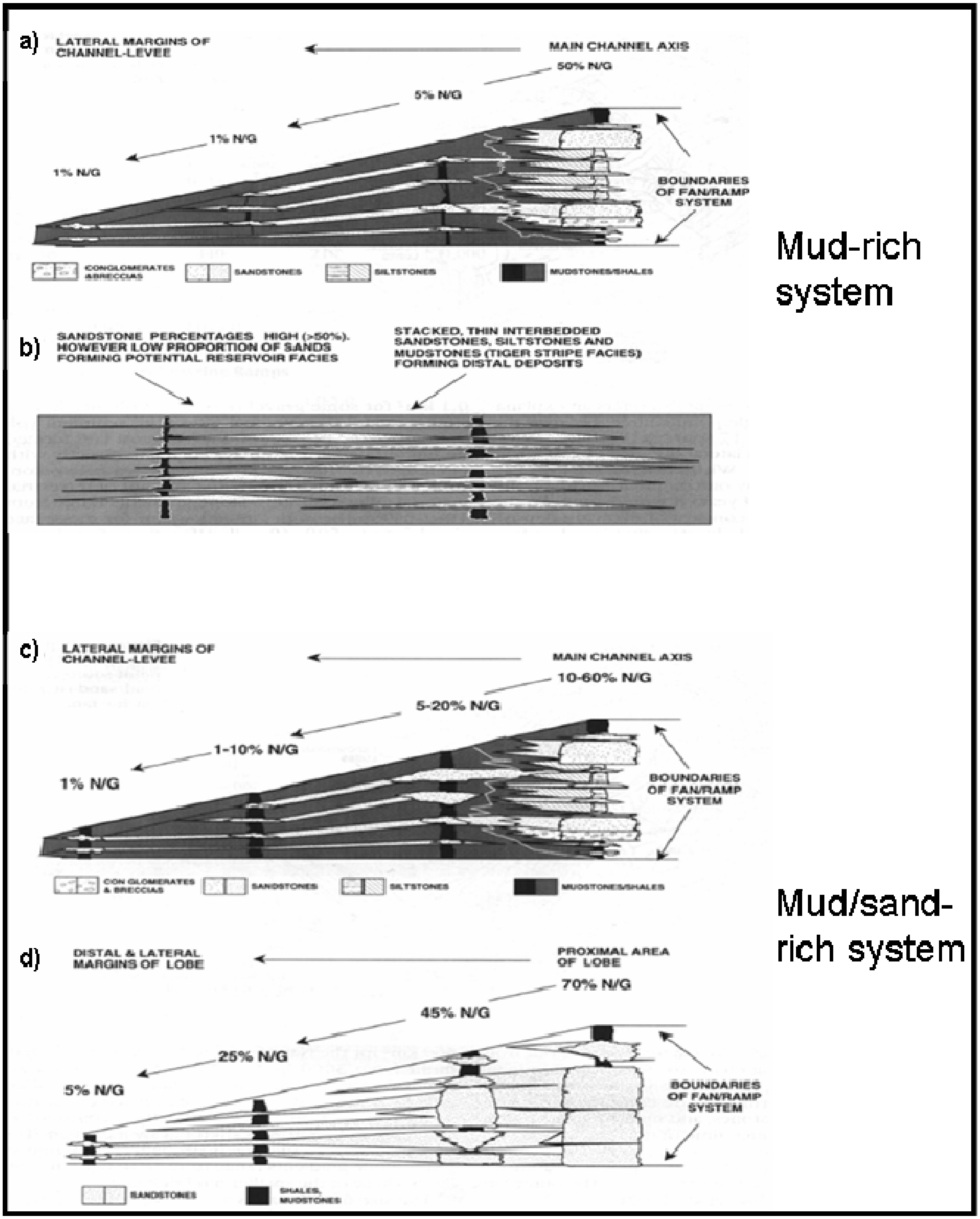


Figure 11. Log response of turbidite fan systems (Reading and Richards, 1994).
a) Channel system; b) Distal portion of channel facies; c) Channel system;
d) Proximal to distal axis of fan lobe.

3.3 New Concepts and Research

3.3.1 Shelf-Margin Deltas

There is a range of delta types that can develop across the shelf during a rise and fall of relative sea level. Shelf-margin deltas, as opposed to the inner-shelf deltas like the Mississippi, Niger, etc., probably represent the primary increments by which shelf margins grow. These have the potential to become the staging area for supply of sand to the deep water slope (Figure 12). Their identification may be a predictor of coeval deepwater sands on the slope or basin floor (Porebski and Steel, 2003). Cummings and Arnott (2005) and Cummings et al. (2006) have identified and described the shelf margin deltas in the Missisauga formation along the outer edge of the Sable delta offshore Nova Scotia. A number of these are producing gas fields.

Another consideration is the stability of shelf-margin deltas which can be modified by listric, down-to-basin growth faulting (Figure 13). These can significantly modify the distribution of clastics on the self and during lowstands, and are yet another complicating factor in the prediction and detection of potential deep water slope reservoir rocks.

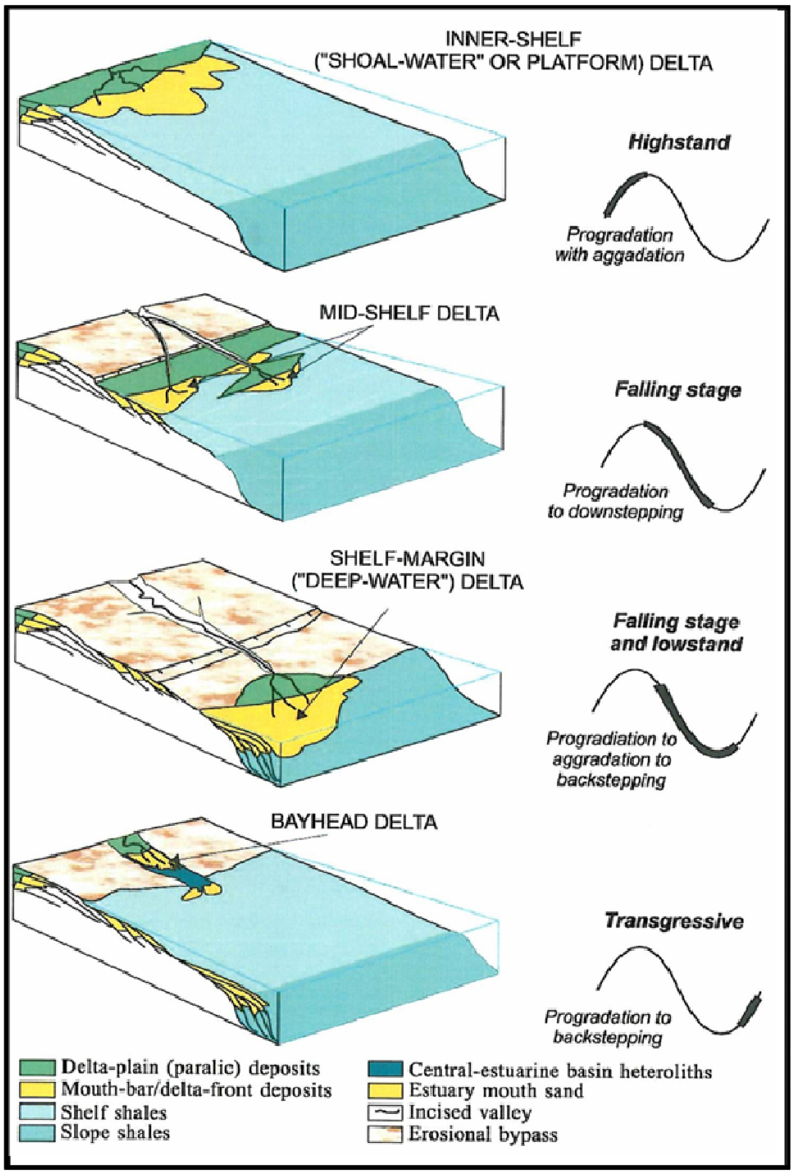


Figure 12. Fan deposition systems track facies model (Porebski and Steel, 2003).

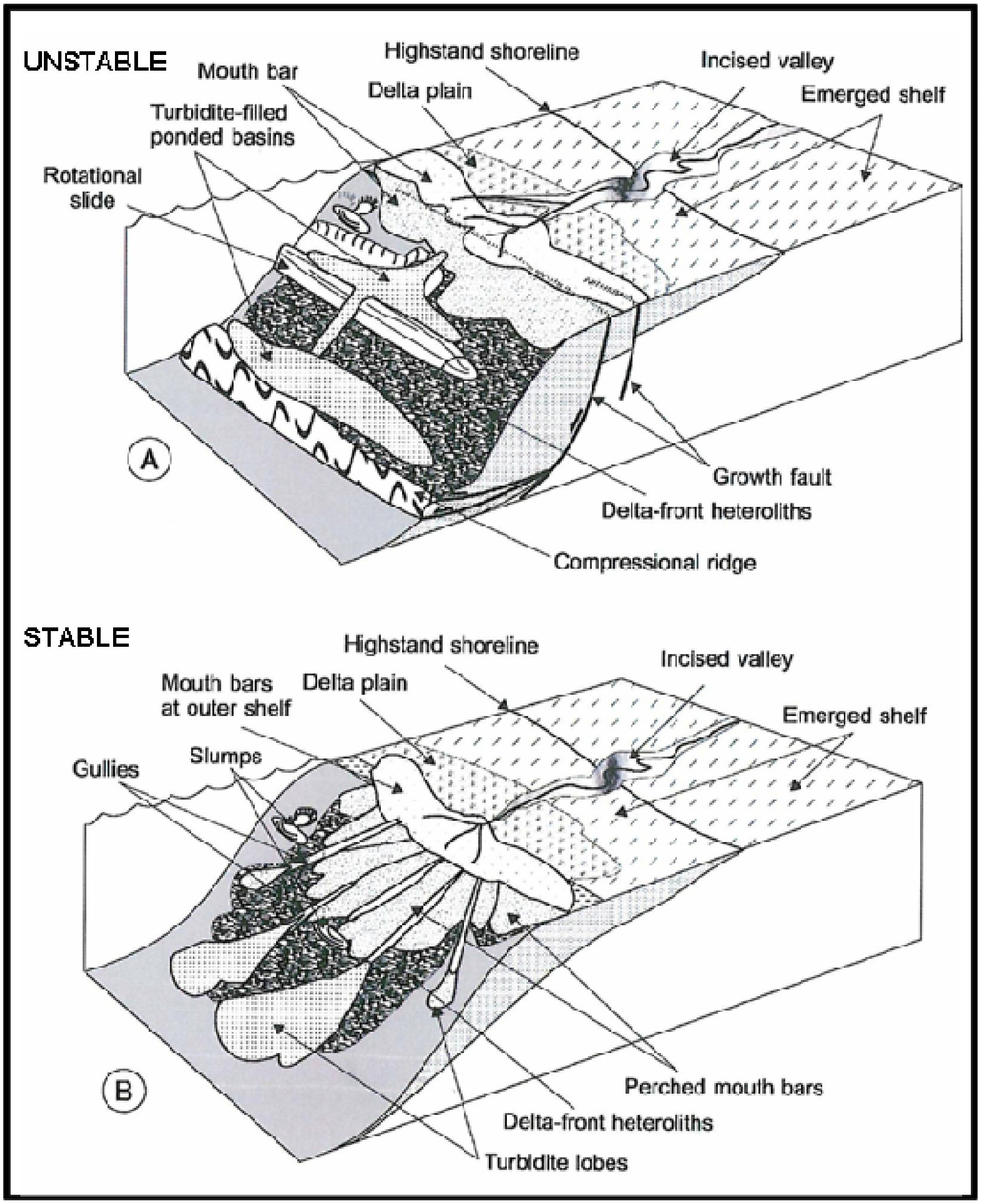


Figure 13. Fan systems in (a) unstable and (b) stable shelf margins (Porebski and Steel, 2003).

3.3.2 Gulf Basin Depositional Synthesis Project (GBDS)

The Gulf Basin Depositional Synthesis Project (GBDS), sponsored by the major operators in the Gulf of Mexico, was created to improve understanding deepwater depositional systems utilizing new datasets and concepts. A recent paper by Combellas-Bigott and Galloway (2006) describes the depositional and structural evolution of the Middle Miocene depositional episode in east-central Gulf of Mexico which is the most prolific producing interval in the Gulf. An example of one of the genetic cycles/seismic sequences (Figure 14) illustrates the level of detail and shelf to basin floor synthesis that is possible. The switching of depositional fairways and bypass zones is crucial to high-grading exploration prospects but, like the GBDS project, it requires a high well density and a detailed basin sequence stratigraphic framework.

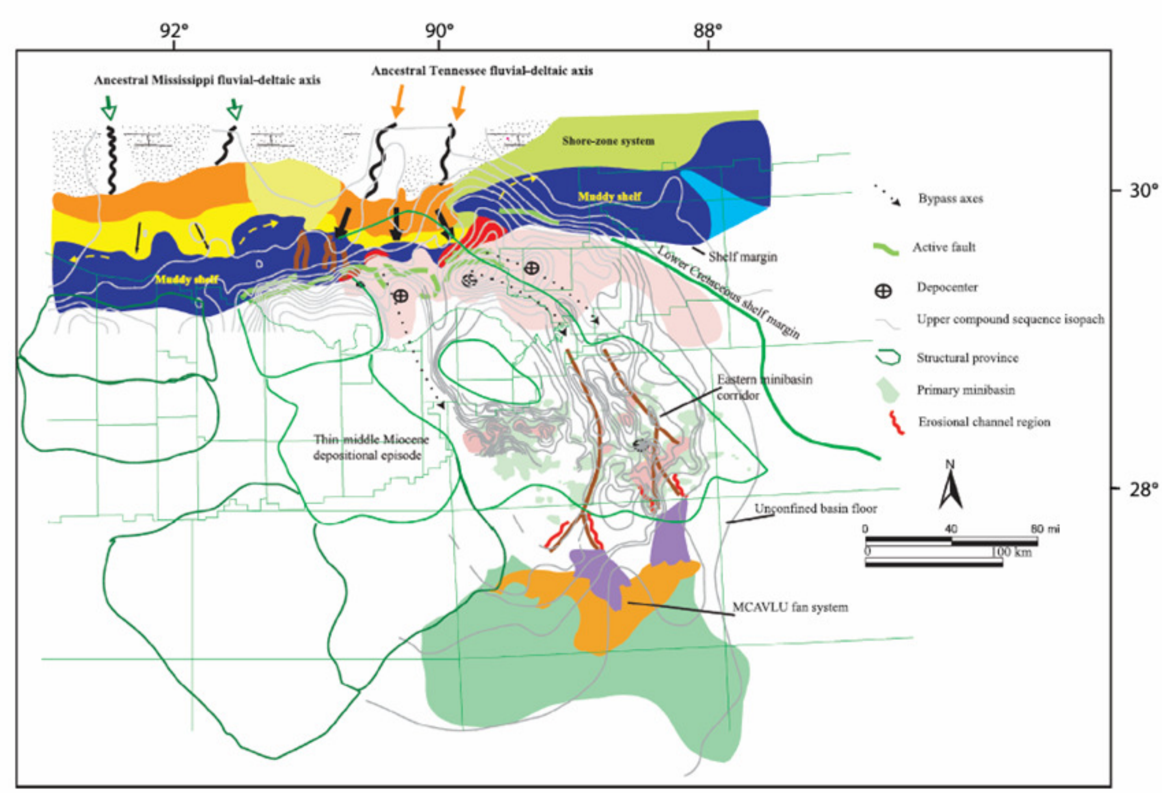


Figure 14. Paleogeographic map of an ancient fluvial-deltaic fed deepwater fan system in the Gulf of Mexico (Combellas-Bigott and Galloway, 2006).

3.4 Exploration Techniques

Three research papers from Exxon (1984), Petrobras (1994) and Shell (2005) illustrate the evolving exploration methodologies employed by industry over the past two decades.

Exxon, R.M. Mitchum Jr. (1984, 1985)

Following success in the North Sea, Mitchum (1984, 1985) described the seismic criteria for submarine fan recognition. The primary criteria were:

- Understanding regional basin setting and age relationships prone to fan deposition.
- Defining the fans and their extent by mapping fan morphology
- Outlining their internal geometry to interpret facies distribution within.

Figure 15 illustrates their 1984 understanding of the seismic facies of an idealized canyon-fan system. The major observations were:

- Most reservoir quality sands in submarine fans are deposited as turbidites.
- Eustatic falls and lowstands of sea level appear to be times of preferential deposition of submarine fans.
- During falling sea level, canyons are cut and lower slope fans deposited.
- Lowstand: upper slope fan deposition with canyon backfill.
- Rising sea level: continued canyon backfill.
- Highstand: canyons are filled, shelf edge progrades, clastics trapped on shelf.

Mitchum (1984, 1985) also described several pitfalls in seismic misinterpretation of lobate or mounded seismic appearance as turbidite deposits:

- lobate clinoform slope sequences
- mounds due to detached normal faults
- internal moundy reflections from slumps
- contourites
- erosional remnants

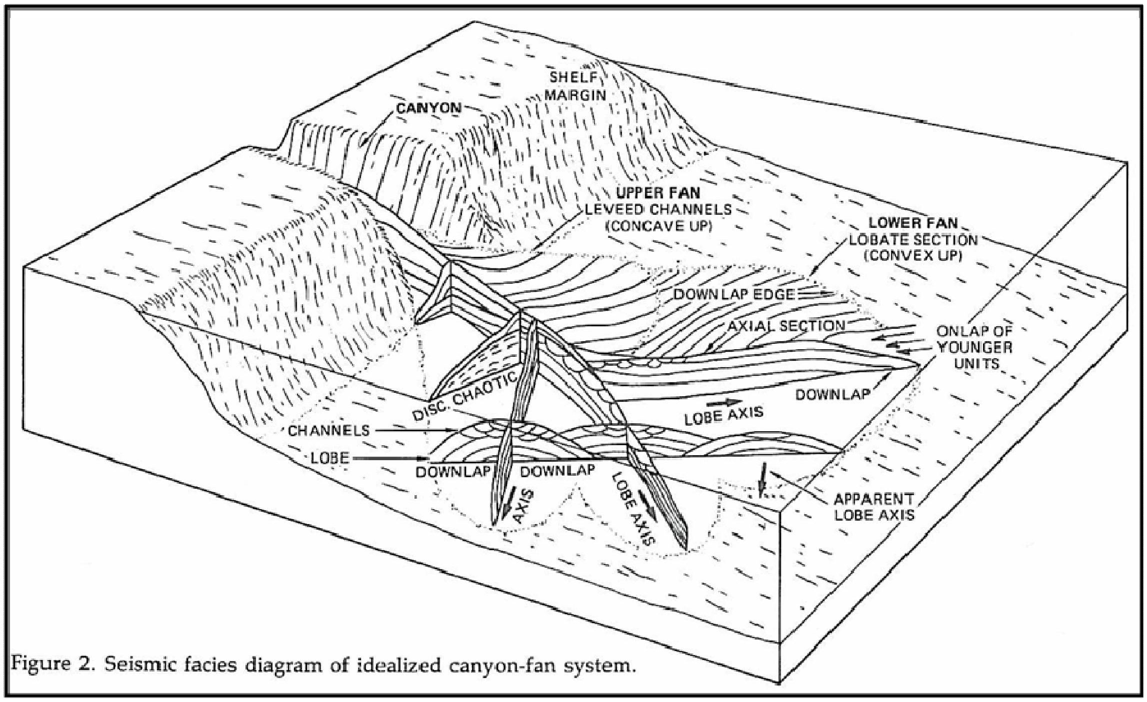


Figure 15. Seismic facies diagram of idealized canyon-fan system (Mitchum, 1984).

Petrobras, C. Cainelli (1994)

Cainelli (1994) described exploration planning for turbidite reservoirs based on experience in the Sergipe-Alagoas Basin offshore Brazil and recommended the following process:

- Consider the processes controlling sand distribution on the shelf.
- Map sandy shelf facies that could provide greater chances for sand-rich turbidites downslope.
- Identify pathways to transport shelf sands into slope/basin sites.
- Highgrade the sand-prone parts of the canyon/fan/turbidite system.

In the Sergipe-Alagoas Basin, carbonates along the outer shelf rim were recognized as barriers that trapped most shelf sands behind them. Therefore, mature canyons which breached the carbonate rim and accessed the behind-barrier sands were the most important routes for sand transport into the deepwater.

Shell, F. Love et al. (2005)

Love et al. (2005) described an exploration methodology for canyon/fan systems in the Northern Espirito Santo Basin, offshore Brazil:

- The controlling factors are eustasy and sediment supply, (i.e. an active river system), basin subsidence and tectonic controls including salt tectonics.
- The main method for predicting Eocene and younger reservoirs are high amplitudes within the canyons.
- For older Cretaceous plays amplitudes do not appear as a good reservoir indicator. The method of flattening on interpreted condensed sections and finding bidirectional downlap to indicate canyons is used.
- Hence the needs are sequence stratigraphy, seismic attribute mapping and 3D depth imaging.

3.5 Worldwide Analogues

Numerous hydrocarbon-bearing submarine fan complexes are known in basins around the world particularly in the circum-Atlantic realm, and are mostly of Tertiary in age. For a variety of rock property-related criteria, the seismic imaging and measurement of seismic attributes is superior to older pre-Tertiary sections. The following summary of global analogues provides insight on the attributes and features of deepwater submarine fans complexes.

3.5.1 North Sea

The North Sea Frigg field was discovered in 1970 and is an early example of successful submarine fan seismic detection and mapping (Figure 16). The lobate map form (Figure 17) was based on the limits of seismic cycle thickening (Figures 18 & 19) below the top of the Frigg sand. Once the relationship between this isochron thick and reservoir was established, exploration success followed.

A more recent example is the Tay and Forties/Sele sand-rich basin-floor fans in the Central North Sea (Figure 16). The advances in 3D seismic isochron fan mapping (Figure 20) shows the Eocene Tay fan isochron and paleogeographic reconstruction. The deeper Paleocene Forties fan is also shown. The seismic profiles and well-log cross-sections of Figure 21 illustrate the signature of thick sand-prone channels. These are from a study by Jennette et al. (2000) in the Forties Field area that used a large amount of 3D and 2D seismic and logs from 350 wells. Clearly, in this and other examples, a large database is required. When compared to the frontier Scotian Slope, there is a critical point where a sufficient number of wells, seismic data and drilling success is required to determine the relationships between seismic and reservoir.

A very recent example of a successful fan play discovery is EnCana's Buzzard field just off the Scottish coast in the North Sea (Forster, 2005) (Figure 16). The reservoir is Late Jurassic age base-of-slope gravity flow sandstones. With a hydrocarbon column of 229m, the recoverable reserves are estimated at 400 million barrels. The seismic profile (Figure 22) shows the Upper Jurassic wedge in front of the paleoshelf break. Well 20/6-3 was successful while 19/10-1 drilled up-dip into a bypass zone and missed the reservoir. The depositional schematic (Figure 23) shows the risk of the first well location to calibrate the seismic response and the process of delineating the reservoir. This ponding of shelfal sediments is analogous to the line-source models of Reading and Richards (1994) (Figure 9).

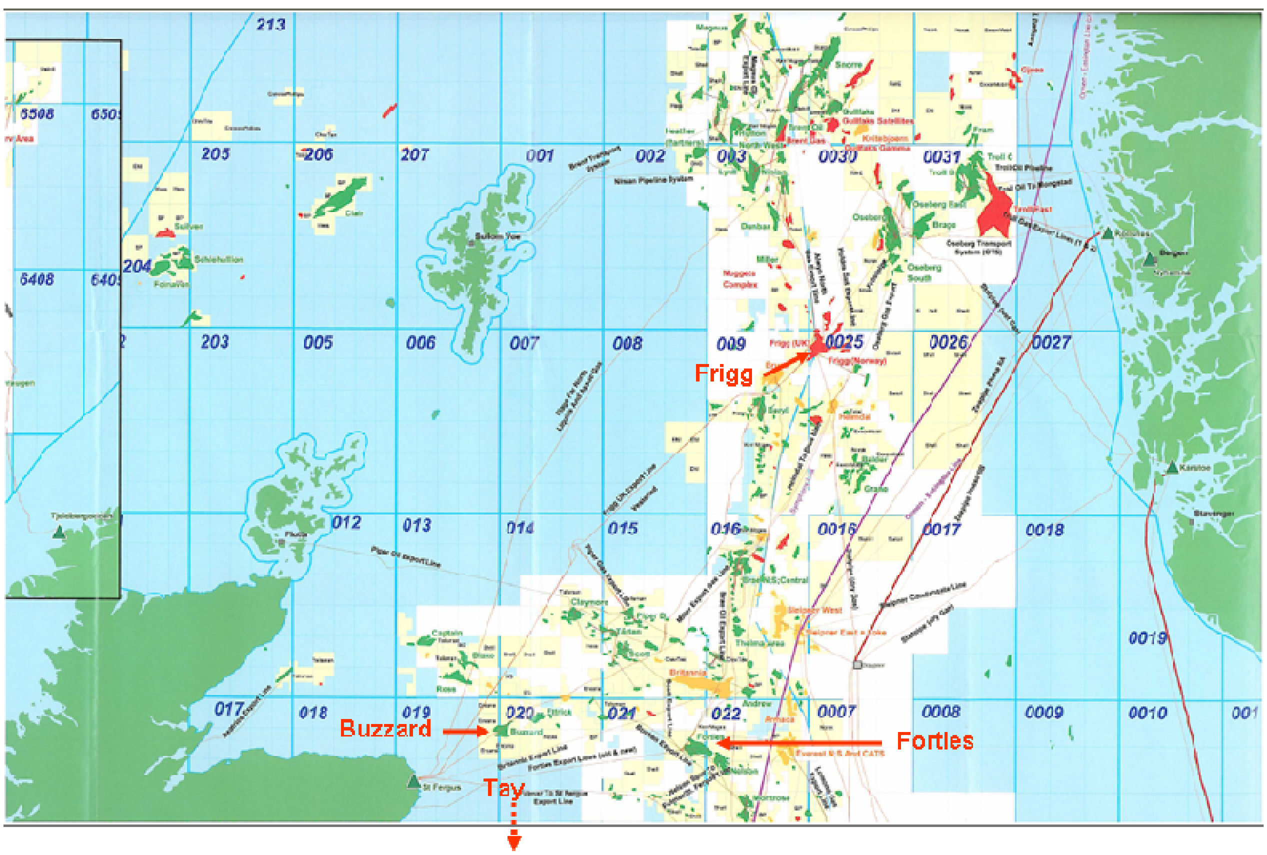


Figure 16. North Sea field location map. The locations of the Frigg, Buzzard, and Forties fields are shown in red. The Tay Field is located south of this map, as indicated.

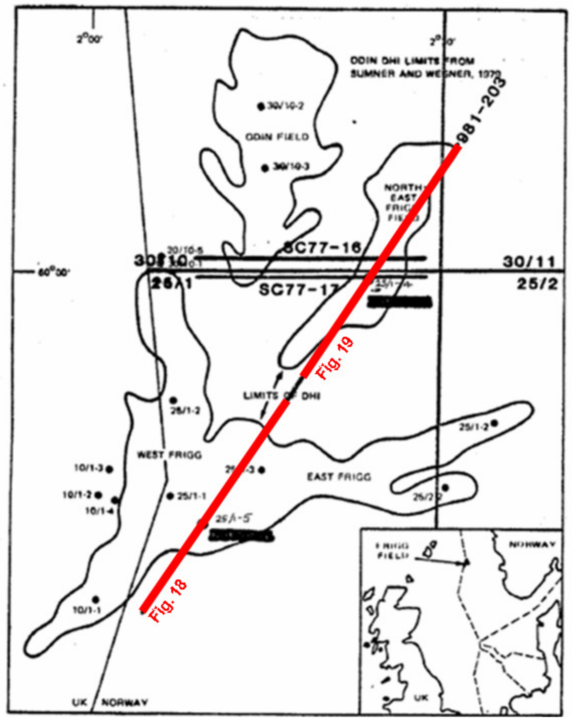


Figure 17. Frigg field location map. Locations of seismic lines 981-203.

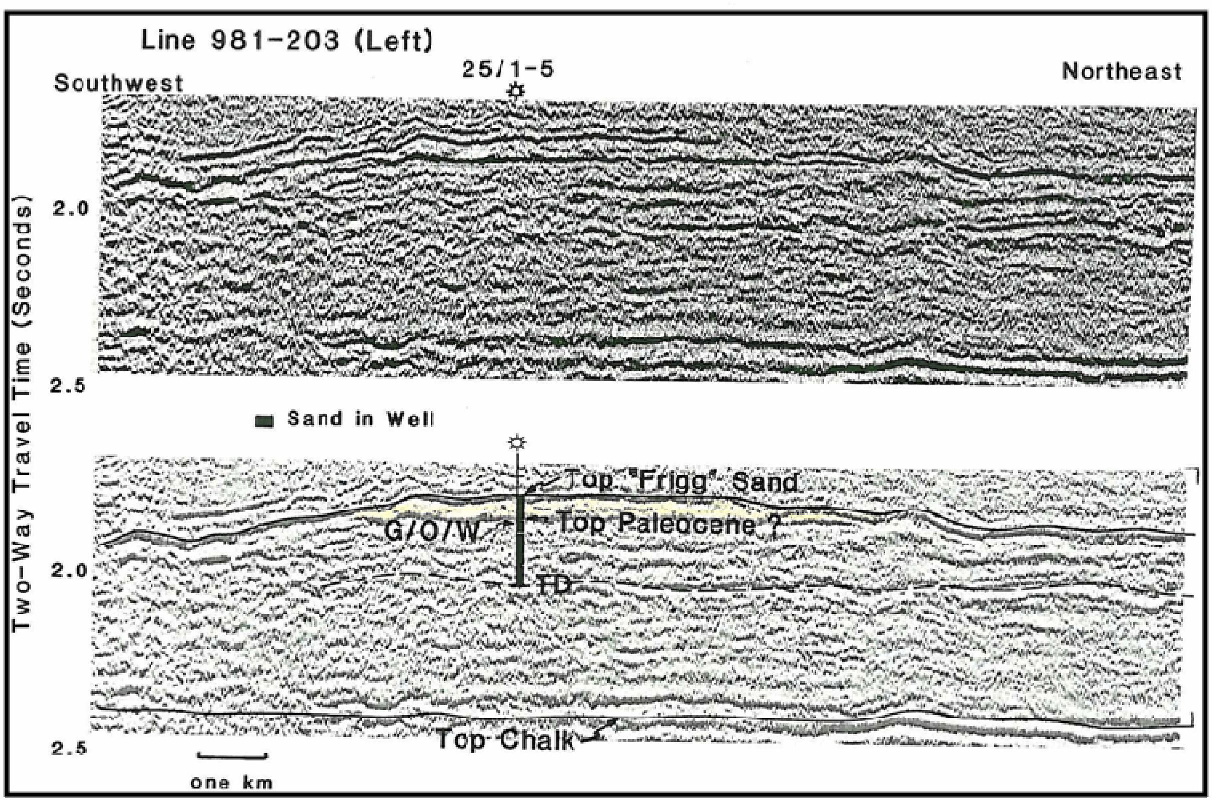


Figure 18. Frigg field seismic line 981-203 (southwest). The top line is uninterpreted, while the bottom line shows the interpreted pay zone (Source unknown).

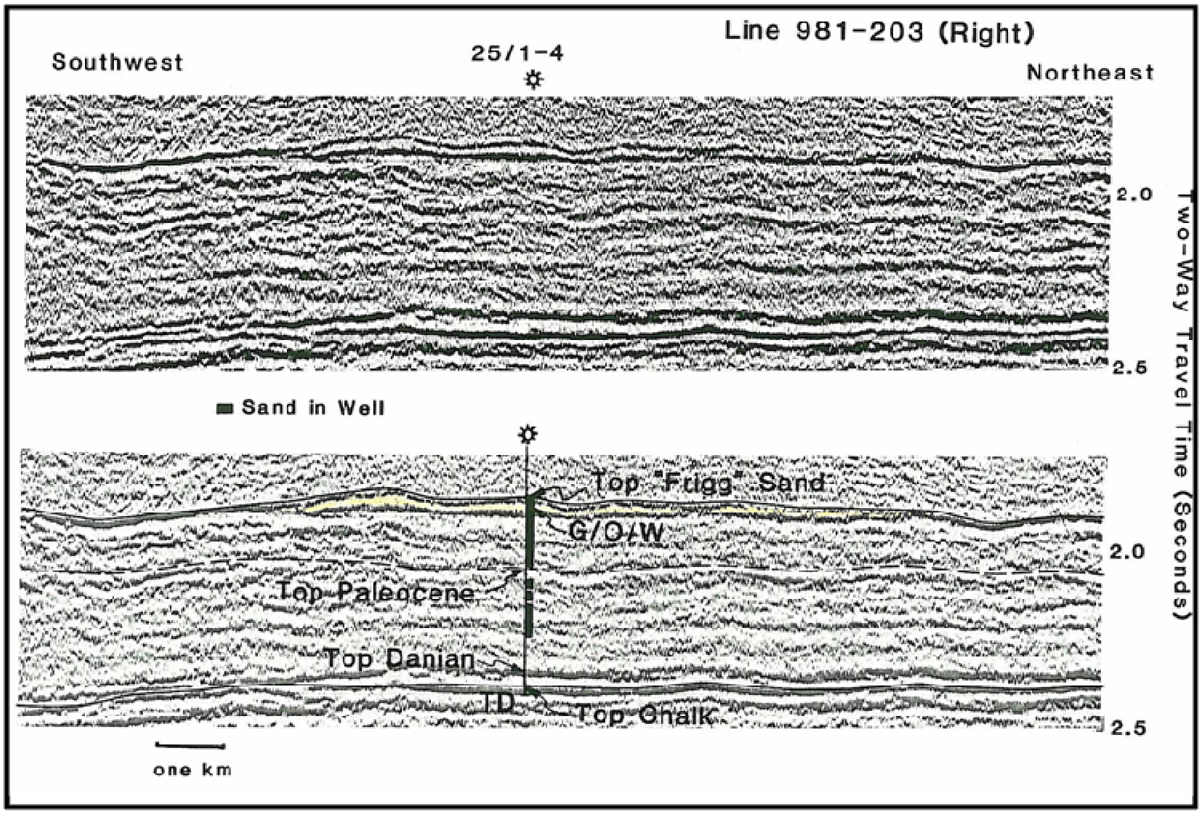


Figure 19. Frigg field seismic line 981-203 (northeast). The top line is uninterpreted, while the bottom line shows the interpreted pay zone (Source unknown).

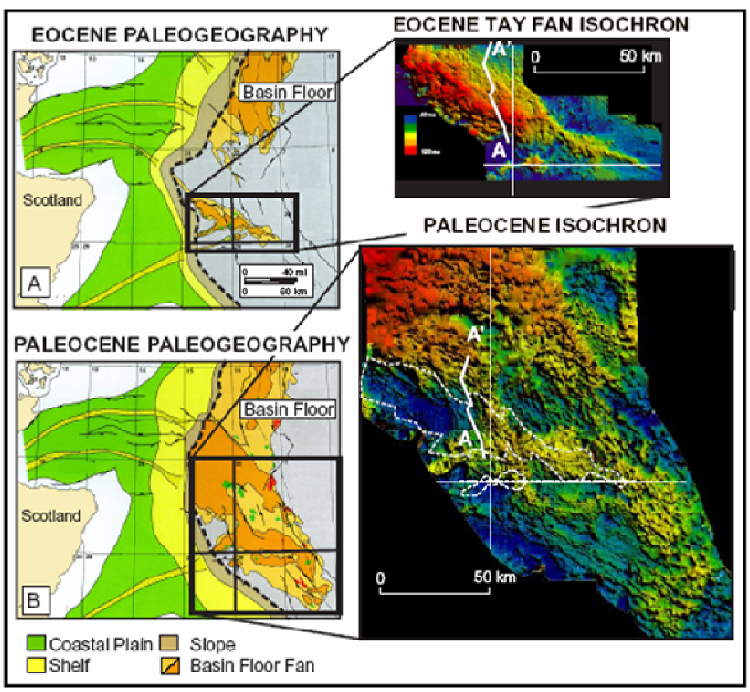


Figure 20. Tay Field paleogeographic and isochron maps for the Eocene and Paleocene pay zones (Jennette et al., 2000).

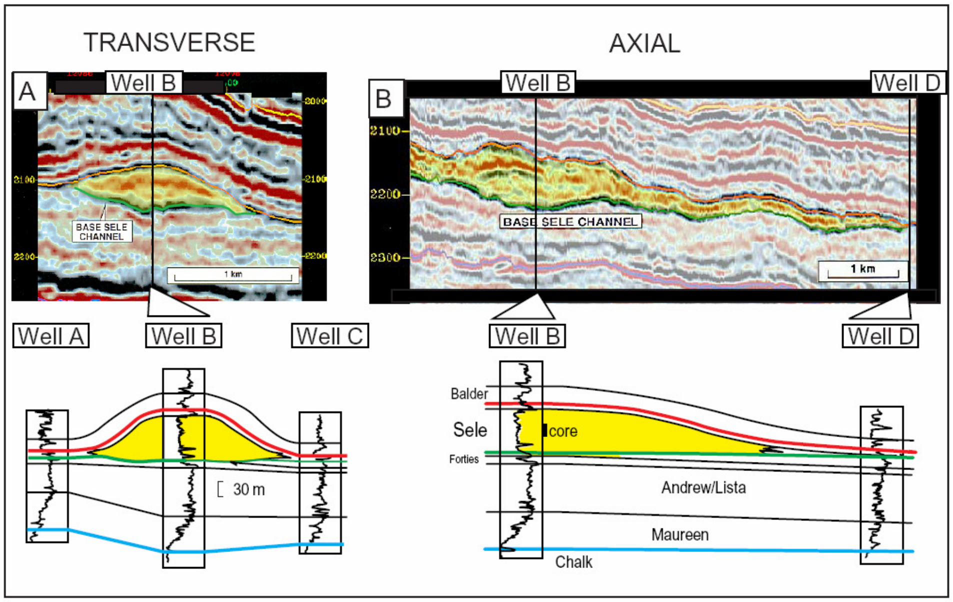


Figure 21. A) Transverse seismic profile and well-log cross-section through the Tay Field. Well B penetrated 75 m of massive sandstone (Sele). Wells A and C encountered no pay in the same interval. B) Axial seismic and well-logs. The reservoir thins downslope, eventually disappearing at Well D (Jennette et al., 2000).

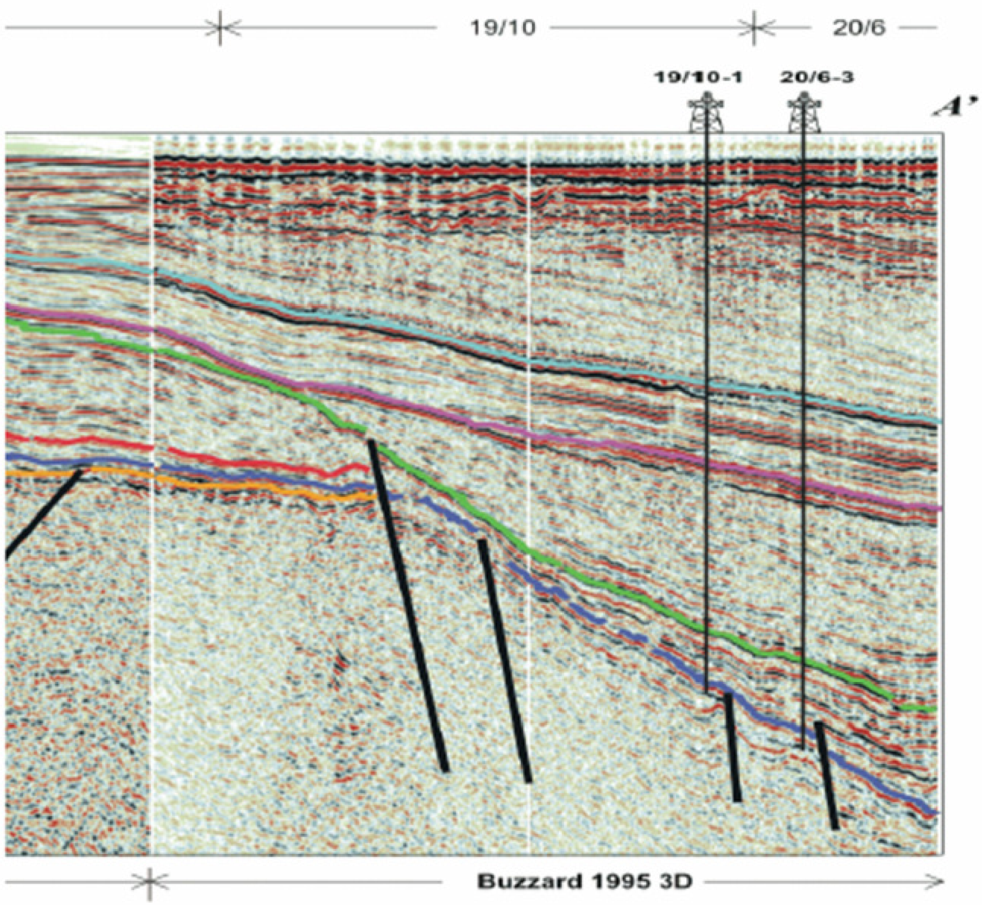


Figure 22. Dip section seismic line through Buzzard Field (Forster, 2005).

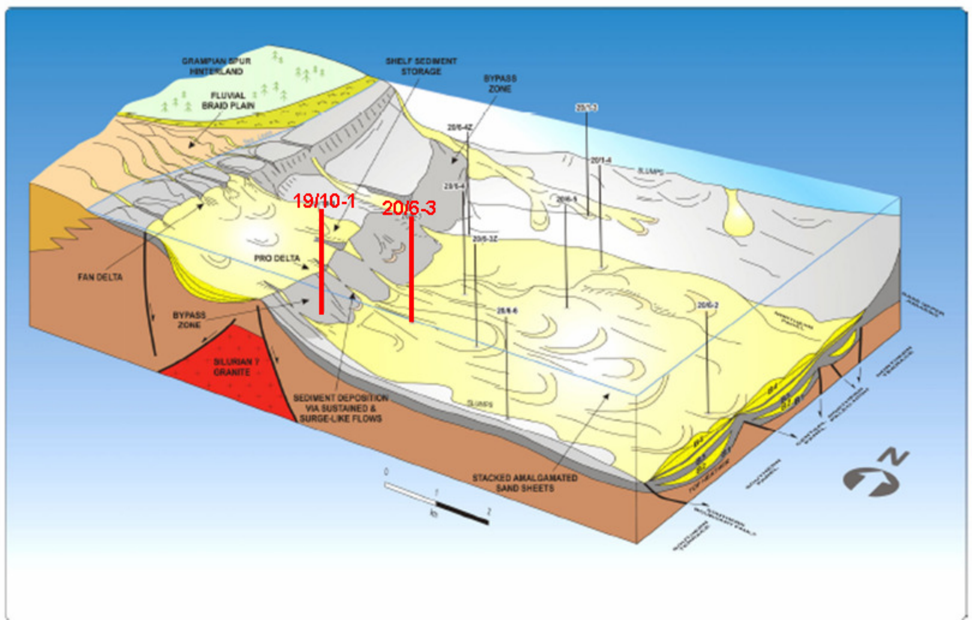


Figure 23. Buzzard Field paleoenvironmental reconstruction. Highlighted wells are on the seismic line in Figure 22 (Forster, 2005).

3.5.2 Gulf of Mexico

The Gulf of Mexico has long been the standard analogy for shelf and deepwater exploration concepts because of the long exploration history, drilling successes and the large amount of available data and published information. A history of industry drilling and changes in salt paradigms can be found in Lore et al (2001). A recent regional discussion by Colling et al. (2001) delineates patterns that are characteristic of the petroleum system in the deepwater of the northern Gulf.

A useful compilation of 34 deepwater discoveries presented in atlas format was published by Weimer et al (1998) in an AAPG Bulletin. This provides key information on each discovery with reservoir specifications, seismic, well logs and location maps. Several examples are included in this report to illustrate points about mini-basins because these paleo-depocentres, once structural lows, are potential targets on the Scotian Slope, as they have had structural reconfigurations into anticlinal features.

An example of mini-basins is shown on the bathymetric map (Figure 24) of the central deepwater Gulf. The ponding of sediments works its way progressively seaward as a function of sediment supply and accommodation space over time (Beaubouef and Friedmann, 2000). There has been a tremendous amount of research done on seismic facies to high-grade the reservoir facies within these mini-basins (Prather et al, 1998). An example of these depositional systems is shown in Figure 25.

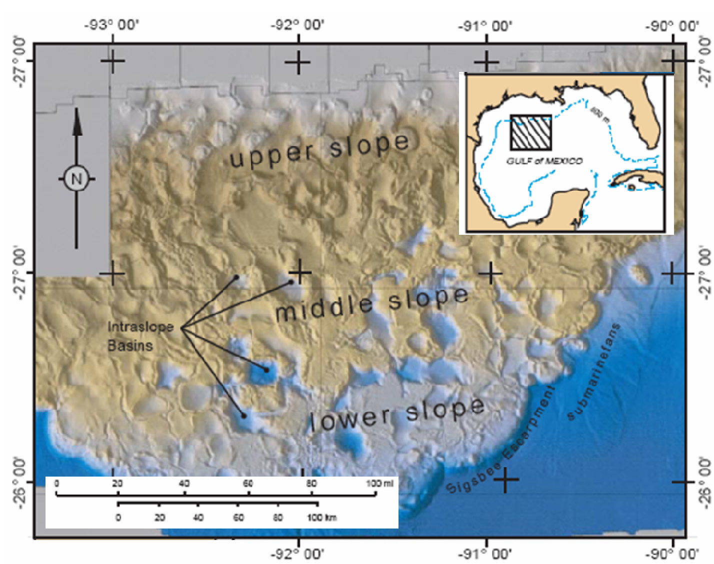


Figure 24. Gulf of Mexico intraslope basin locations. From Prather et al. (1998).

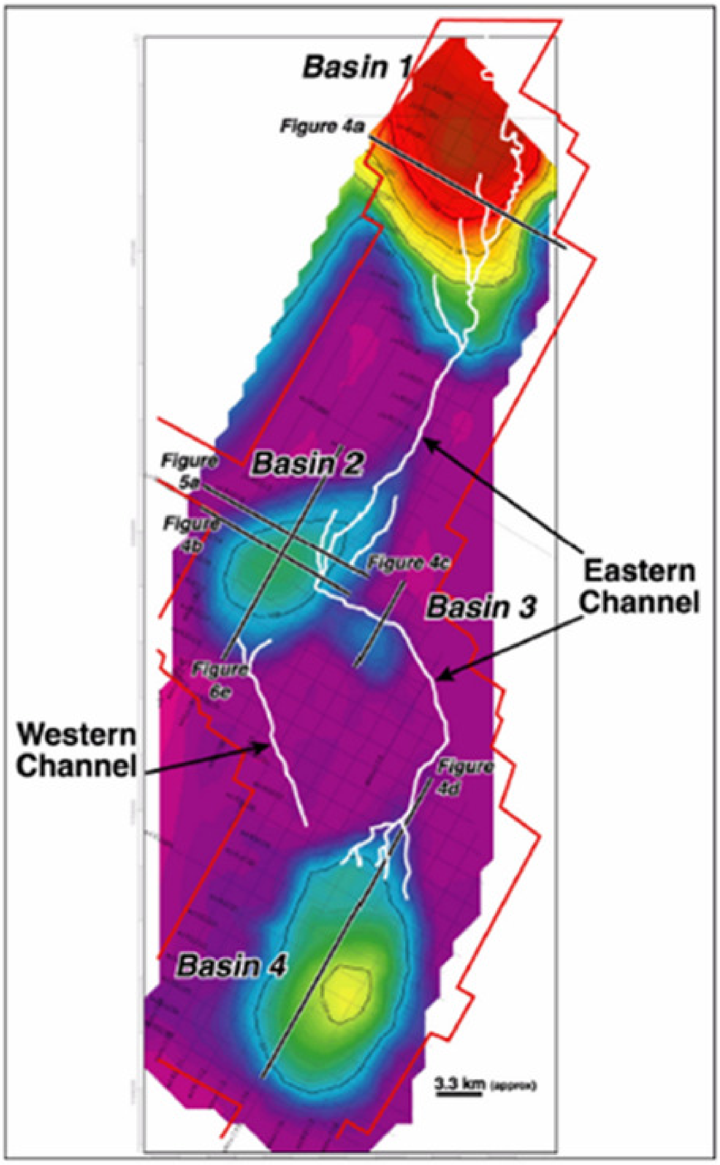


Figure 25. Isochron map of the fill of four intraslope basins in the Gulf of Mexico. Purple indicates thin isochrons, red indicates thick isochrons. The white lines show the channel networks linking the basins (Beaubeouf and Freidmann, 2000).

The 1989 Mars discovery by Shell and BP in 1000m of water depth was a major event. The first well encountered 134m of oil-bearing Miocene-age turbidite sands in six intervals with porosities of 25-32% and permeabilities from 300mD to 3 Darcies. Recoverable reserves were estimated at 700 MBOE (Mahaffie, 1994). Reservoir distribution in cross section and plan view are shown in Figure 26. An uninterpreted and interpreted seismic profile (Figure 27) shows the amplitude anomalies correlative to reservoir. The main point of this example is that Mars is illustrative of a simple undeformed sedimentary depocentre.

Another example is the Auger field (220 MBOE) discovered in 1987 that is representative of an onlapping salt flank play type (Figure 28). The relation between seismic amplitudes and reservoir is clearly shown, and Tertiary-age sections appear prone to visualization via this geophysical attribute.

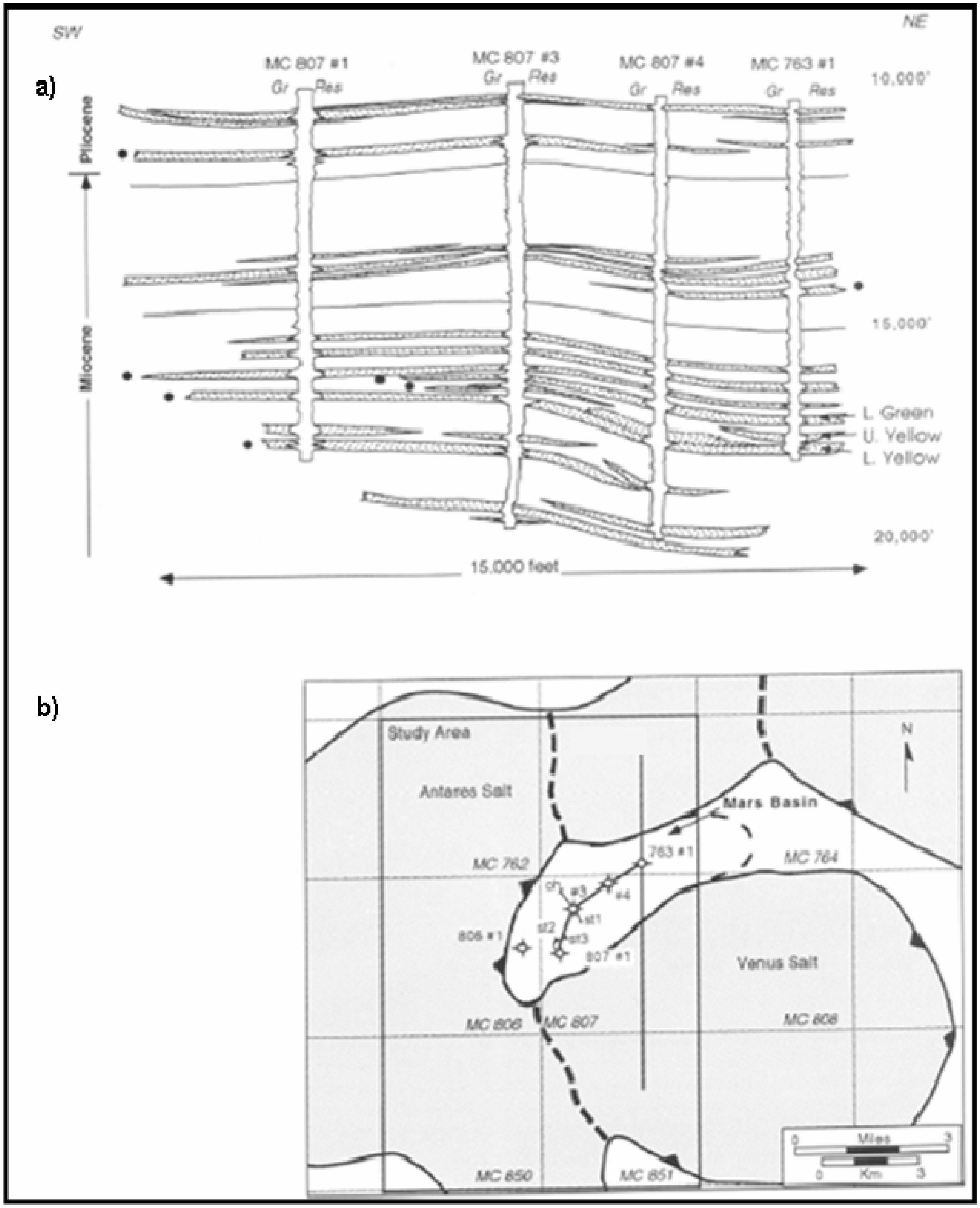


Figure 26. a) Correlation section through the Mars Basin, illustrating the distribution of turbidite sands encountered. Black circles indicate reservoir. b) Base map for the Mars Basin. The black line connecting the wells is the cross-section shown in (a). The vertical line indicates the location of the seismic section shown in Figure 24 (Mahaffie, 1994).

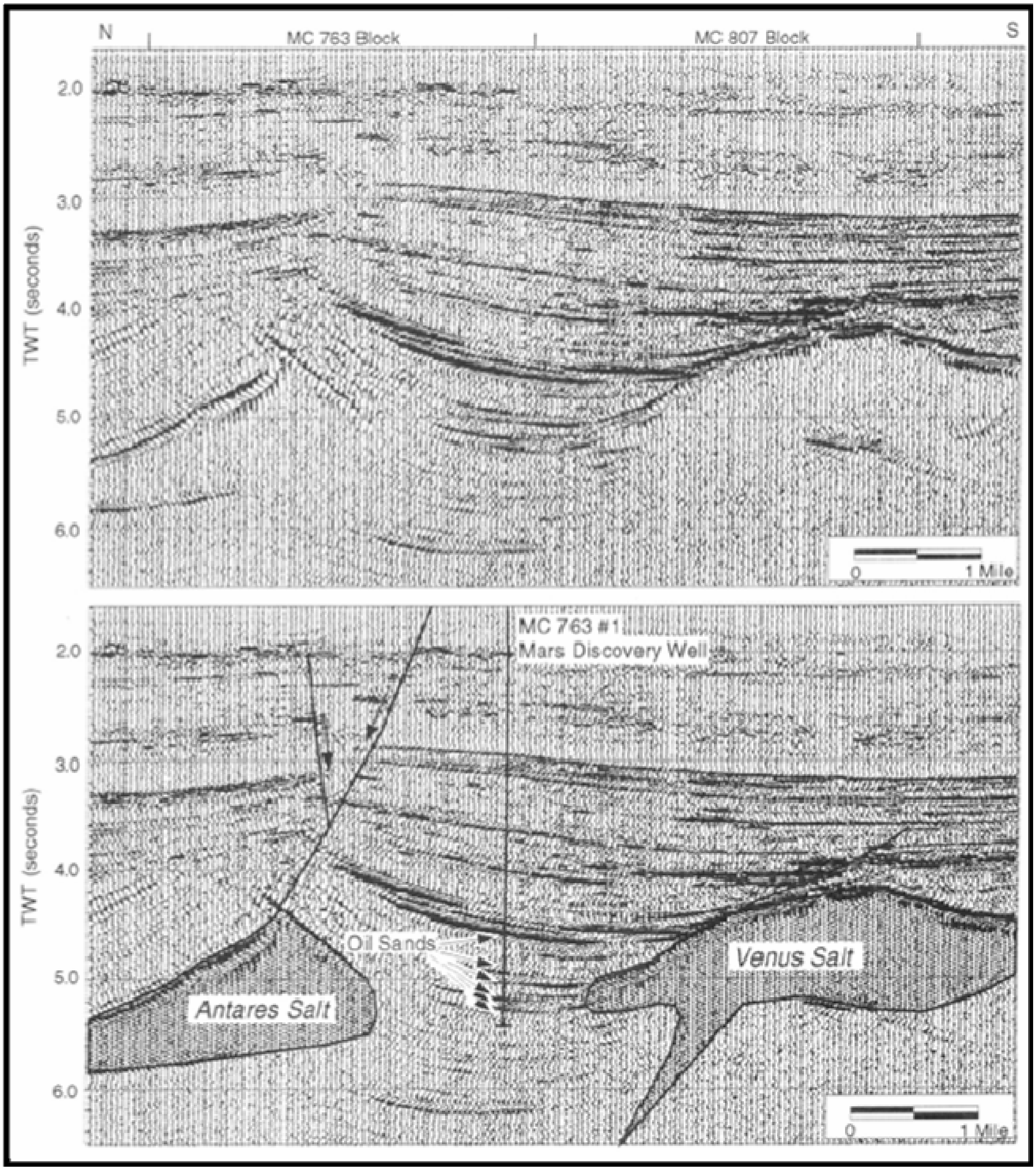


Figure 27. Seismic section through the Mars Field. Top is uninterpreted, bottom is interpreted. The bright amplitude anomalies between the salt bodies represent the major hydrocarbon-bearing sands (Mahaffie, 1994).

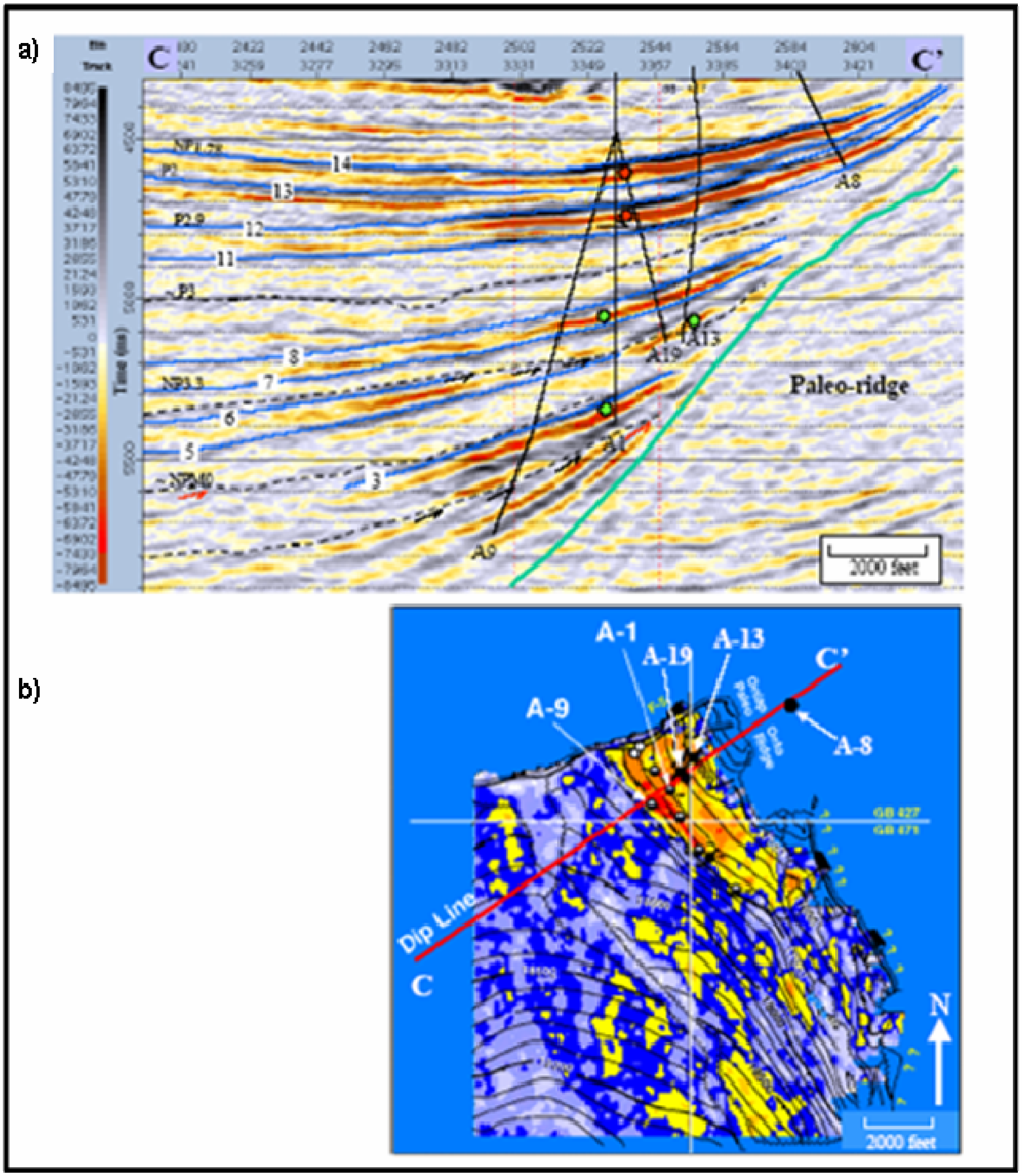


Figure 28. a) Seismic section C-C' through the Auger Field. b) Amplitude/structure map of the Auger Field. Red and yellow colours represent high-amplitude targets (Booth, 2000).

3.5.3 Brazil

The Atlantic-facing margin offshore Brazil has been another huge success story with a number of large deepwater discoveries (Figure 29). The Sergipe/Alagoas Basin is centered on the long-lived Sao Francisco River and delta. Figure 30 is a paleogeographic map of the Oligocene-Quaternary sequence (Cainelli, 1994). The slope is punctuated by a large number of submarine canyons very much like the contemporary Scotian Slope (Figure 2). Of particular interest is the proximity of turbidite sands drilled in front of the shelfal facies (Figure 31) and the interpreted turbidite seismic facies that are so far undrilled. The well log recognition of turbidite system channel sands (Figure 32) displays the fining-upwards or "Christmas tree" character (left panel) as opposed to the mud-rich "spiky" signature (right panel).

The Campos Basin is to date the most prolific basin offshore Brazil with 70 discoveries including 7 giant oil fields in deepwater (Guardado et al., 2000). A very large regional seismic survey was completed by Western-Geco over the Santos and Campos Basins. A similar scale survey on the Scotian Slope was undertaken by TGS-NOPEC. The style and distribution of salt in the Brazilian basins (Figure 33) is remarkably similar to that offshore Nova Scotia (Figure 34). The very large field of salt features is a common attribute to both regions and suggests a large number of potential canyon/fan systems and mini-basins.

Figure 29. Hydrocarbon basins in Brazil (Fainstein, 2003).

Two different yet subtle examples of oil discoveries are useful to consider. A seismic line across the Marlim field (Figure 35) shows the Lower Tertiary reservoir lying above a structural high between two salt rollers. A seismic line across the Albacora Leste field (Figure 36) illustrates a bundle of seismic amplitude events associated with the top Miocene reservoir deposited in a depression on the flank of a salt feature. A series of seismic profiles display common characteristics with the Scotian Slope. A large scale salt withdrawal, ahead of a prograding succession, sets up rim synclines, salt flanks and other intra-salt plays sediments (Figure 37). A Brazilian turtle structure, created as a result of salt withdrawal (Figure 38), is comparable to a Scotian Slope example (Figure 169), as are a series of salt diapirs with intervening mini-basins (Figures 39 & 173). A similar configuration exists in Figure 40 but with the underlying synrift facies containing the rich lacustrine source rocks of the Lagoa Feia formation.

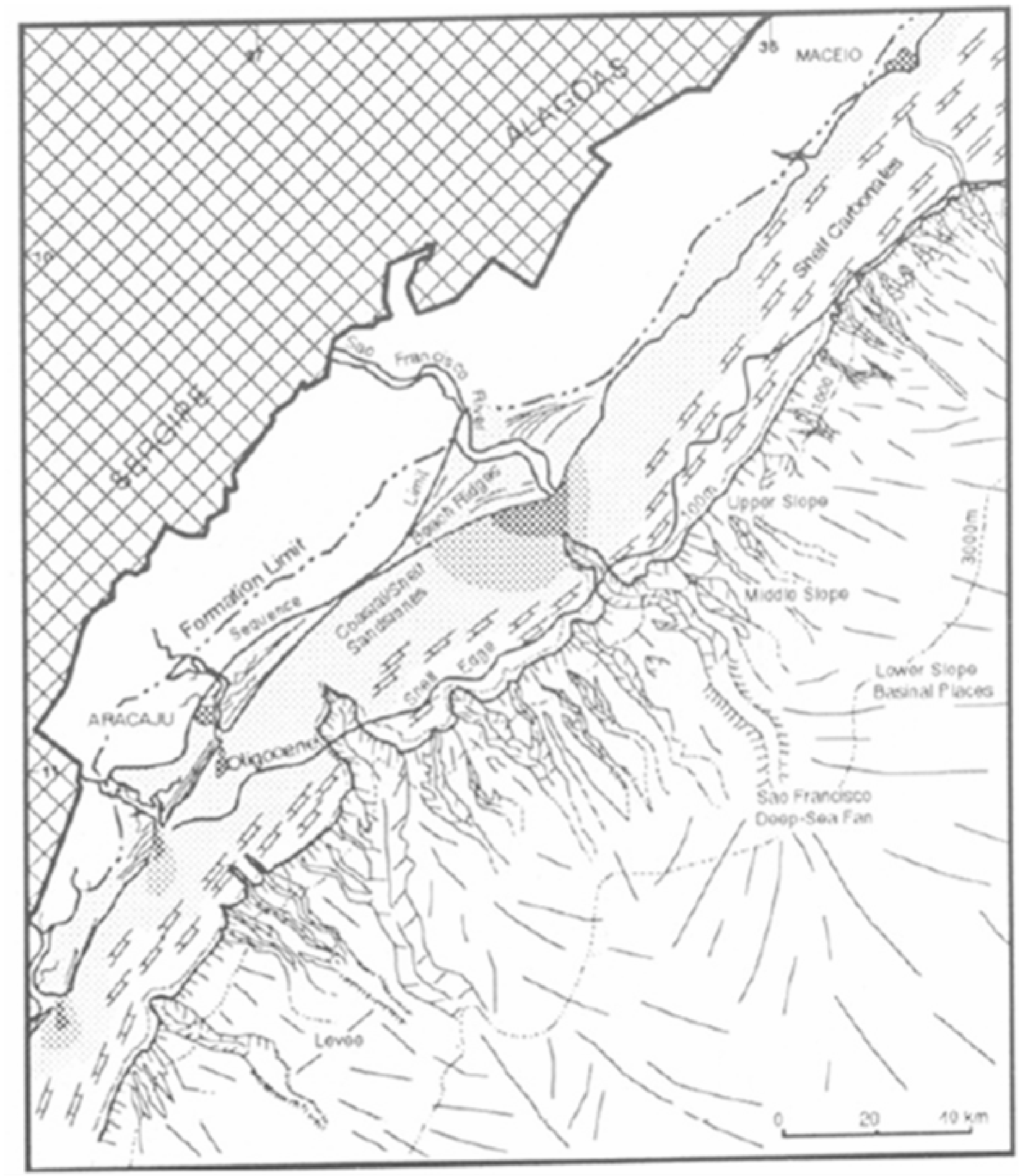


Figure 30. Paleogeographic map of the Oligocene-Quaternary from the Sergipe-Alagoas basin offshore Brazil (Cainelli, 1994).

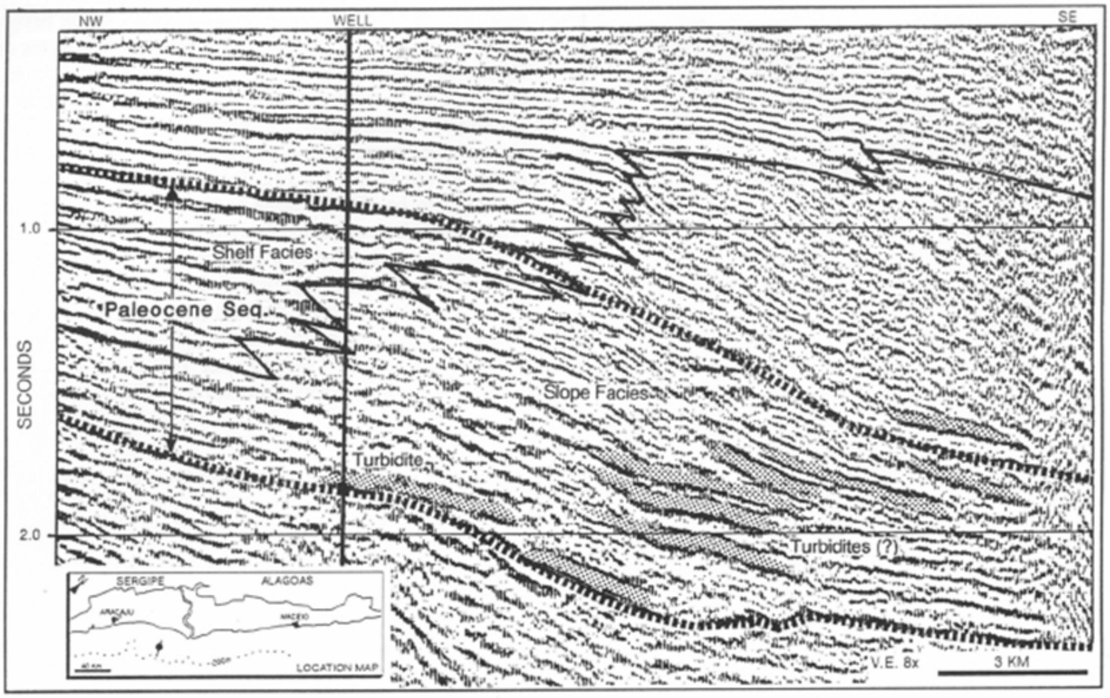


Figure 31. Dip-oriented seismic section showing the expression of a turbidite sandstone (at well location) in the Sergipe-Alagoas Basin (Cainelli, 1994).

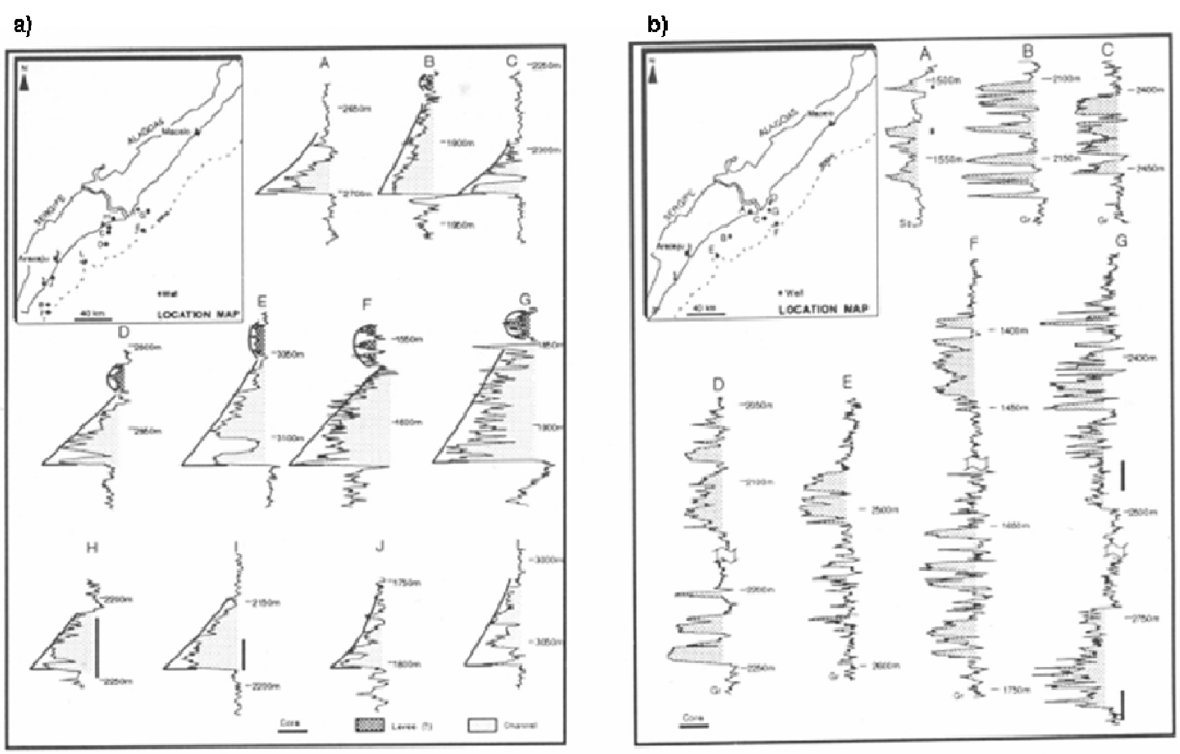


Figure 32. a) Gamma-ray log profiles of interpreted channels with well-defined “Christmas Tree” shapes from turbidite systems in the Sergipe-Alagoas Basin. b) Gamma-ray log profiles of intercalated sand/shale sequences (Cainelli, 1994).

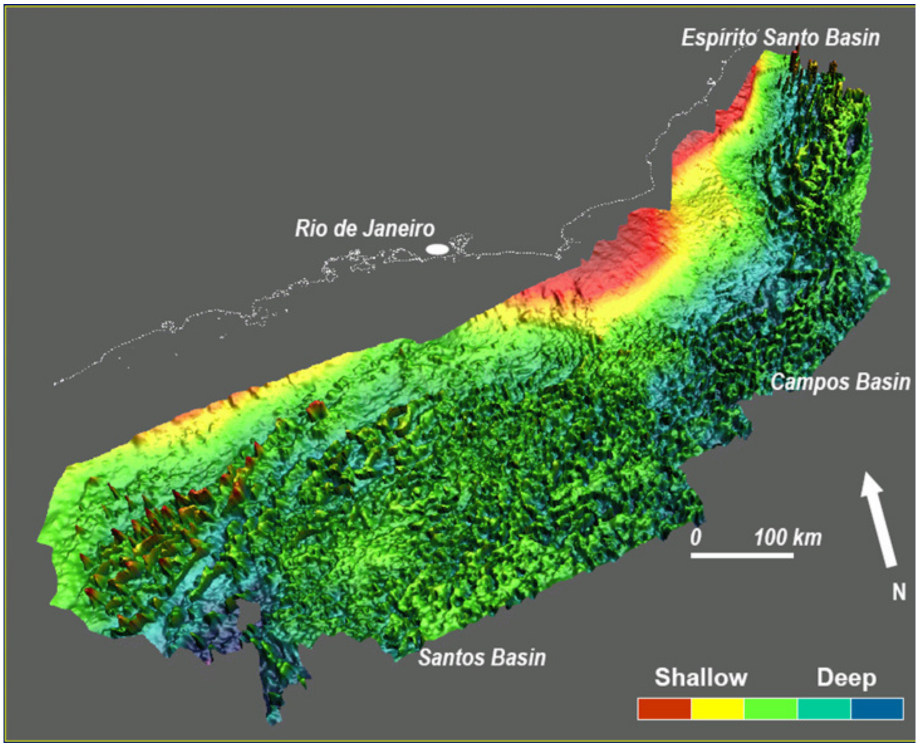


Figure 33. Top Aptian salt in the Campos and Santos Basins, offshore Brazil (Fainstein, 2002).

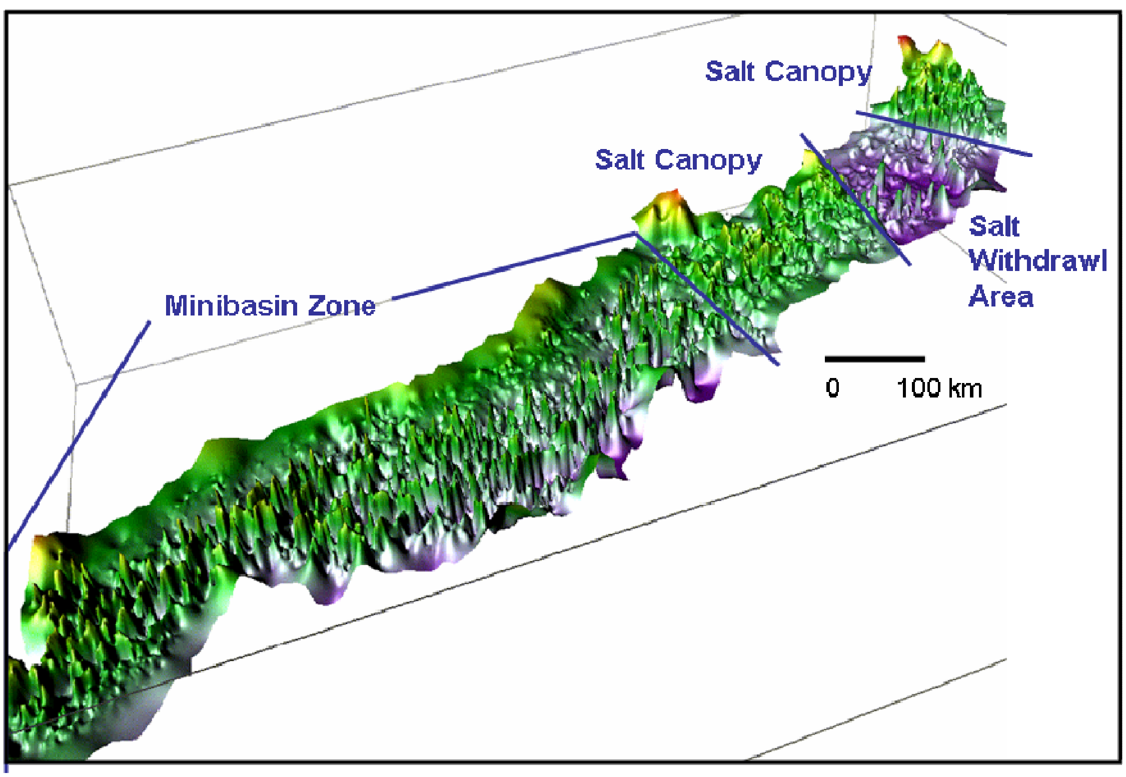


Figure 34. 3-D image of the top Argo Salt in the Scotian Slope.

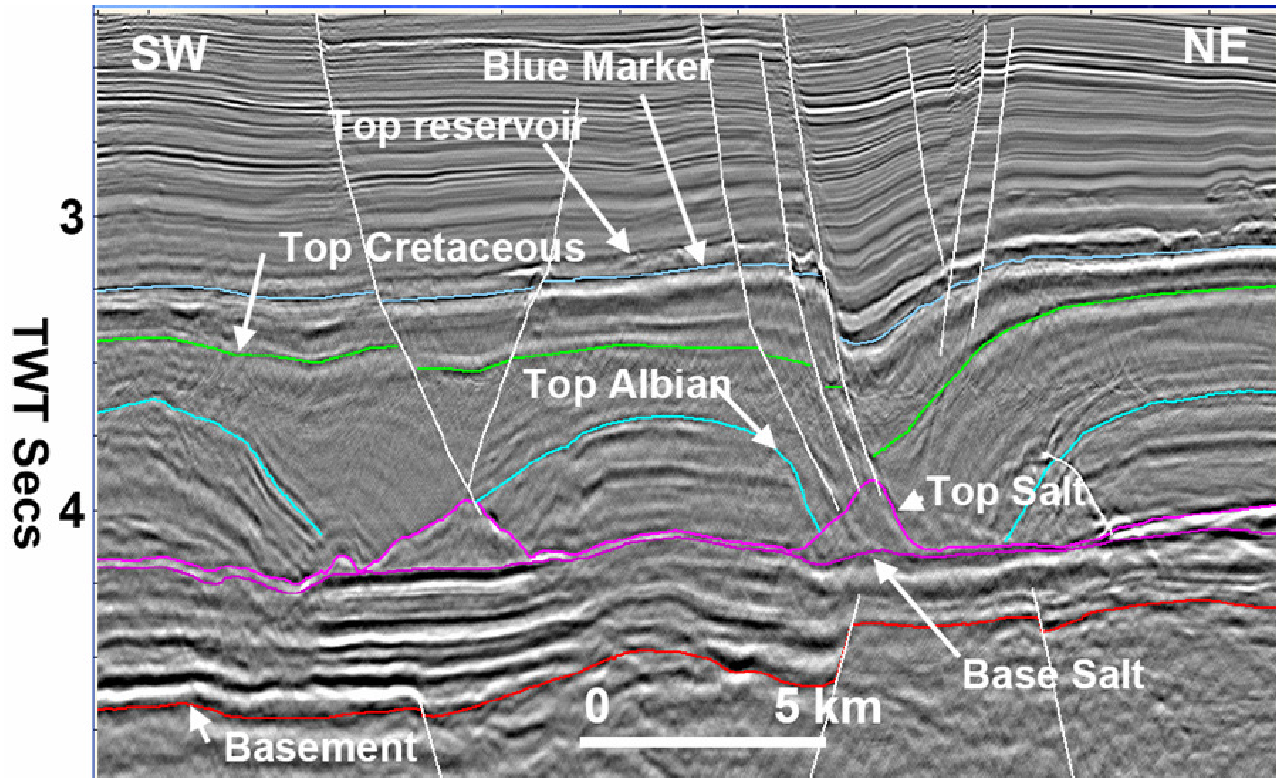


Figure 35. Seismic section from the Marlim Field, Campos Basin, Offshore Brazil (Fainstein, 2003).

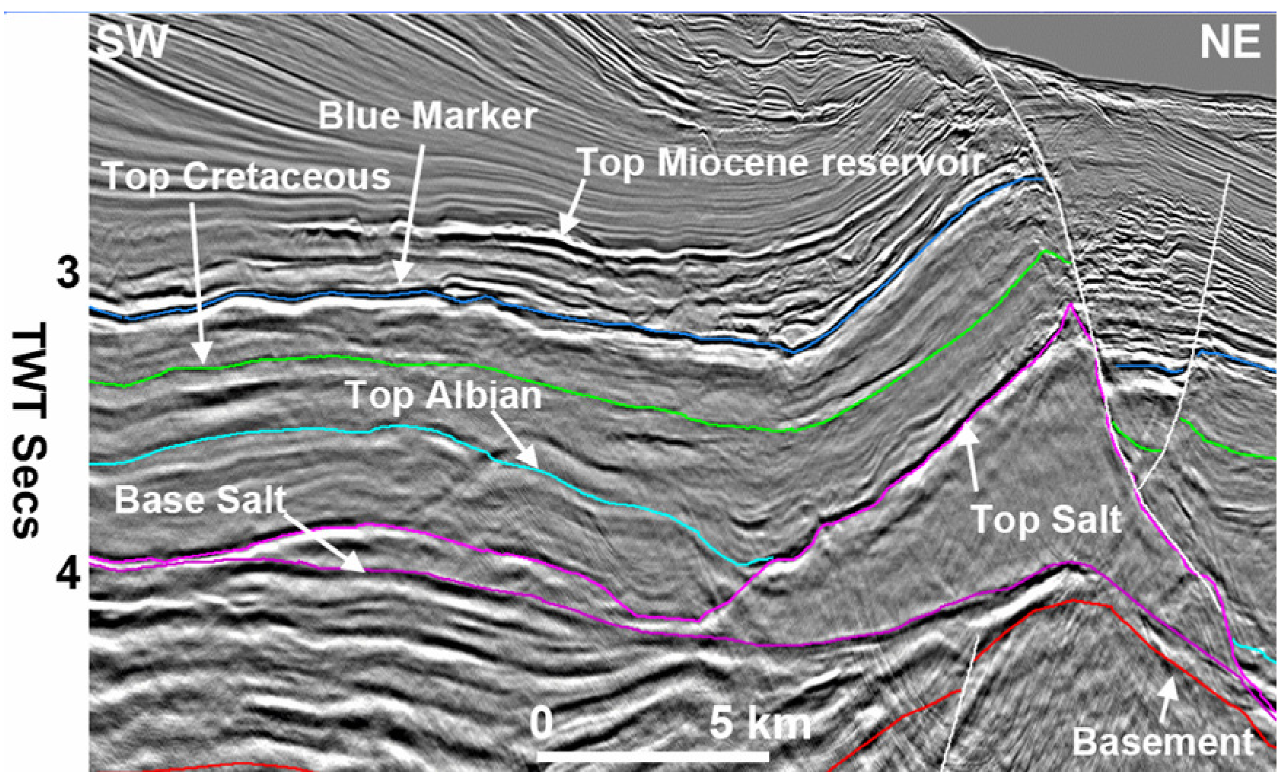


Figure 36. Seismic section from the Albacora Leste Field, Campos Basin, Offshore Brazil (Fainstein, 2003).

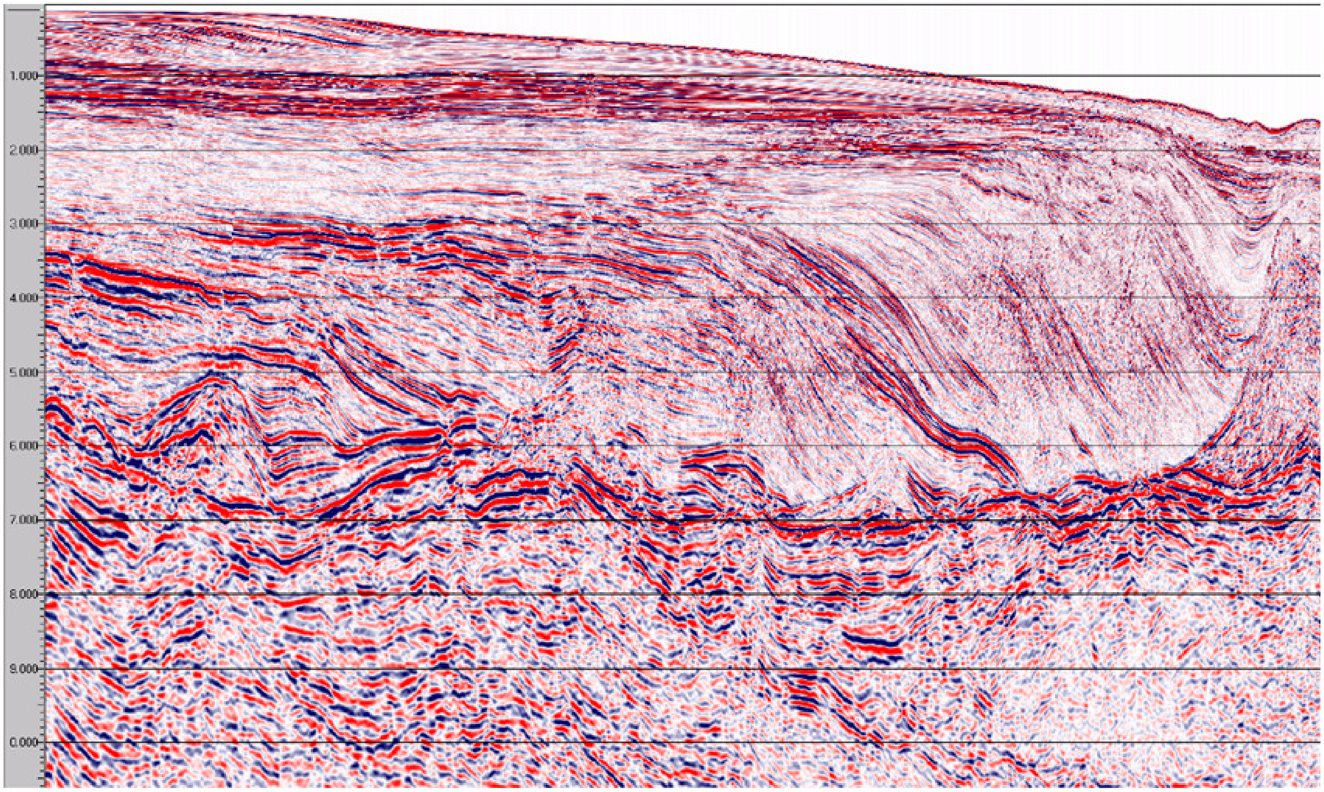


Figure 37. Dip seismic section from the Santos Basin, Offshore Brazil. The structures seen are similar to those of the “Salt Withdrawl” area in the Deepwater Scotian Slope (Fainstein,2003).

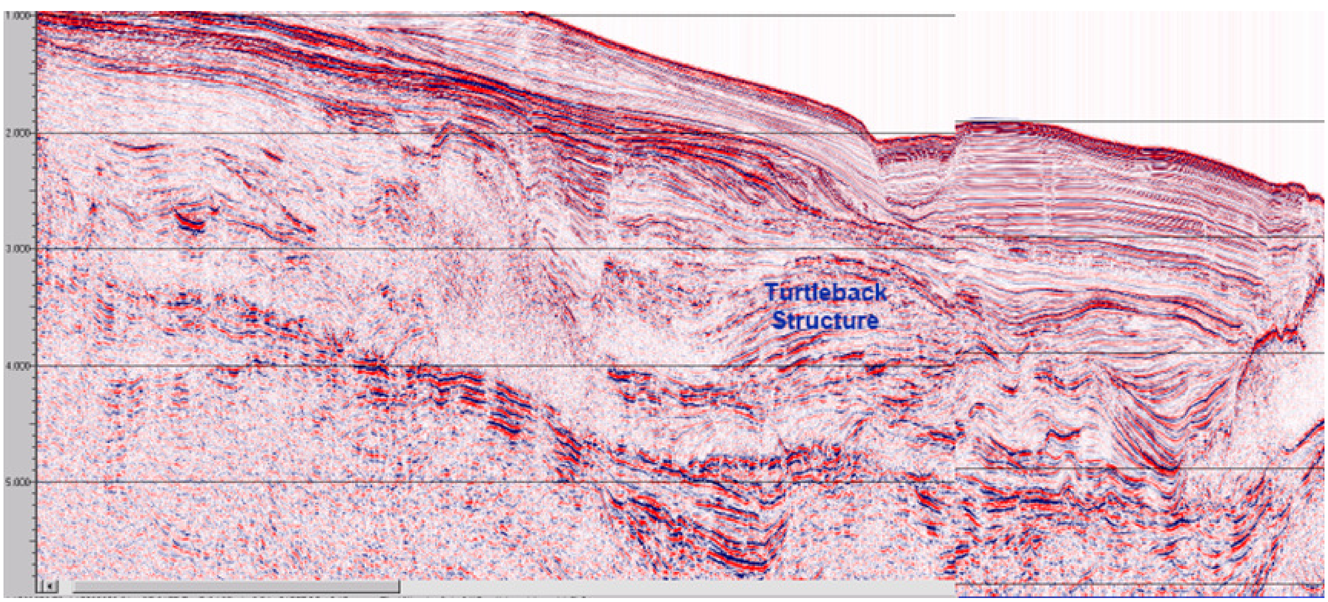


Figure 38. Dip seismic section from the Santos Basin, Offshore Brazil. A turtle-back structure, formed via salt withdrawl, is highlighted. Similar structures are found in the Deepwater Scotian Slope (Fainstein, 2003).

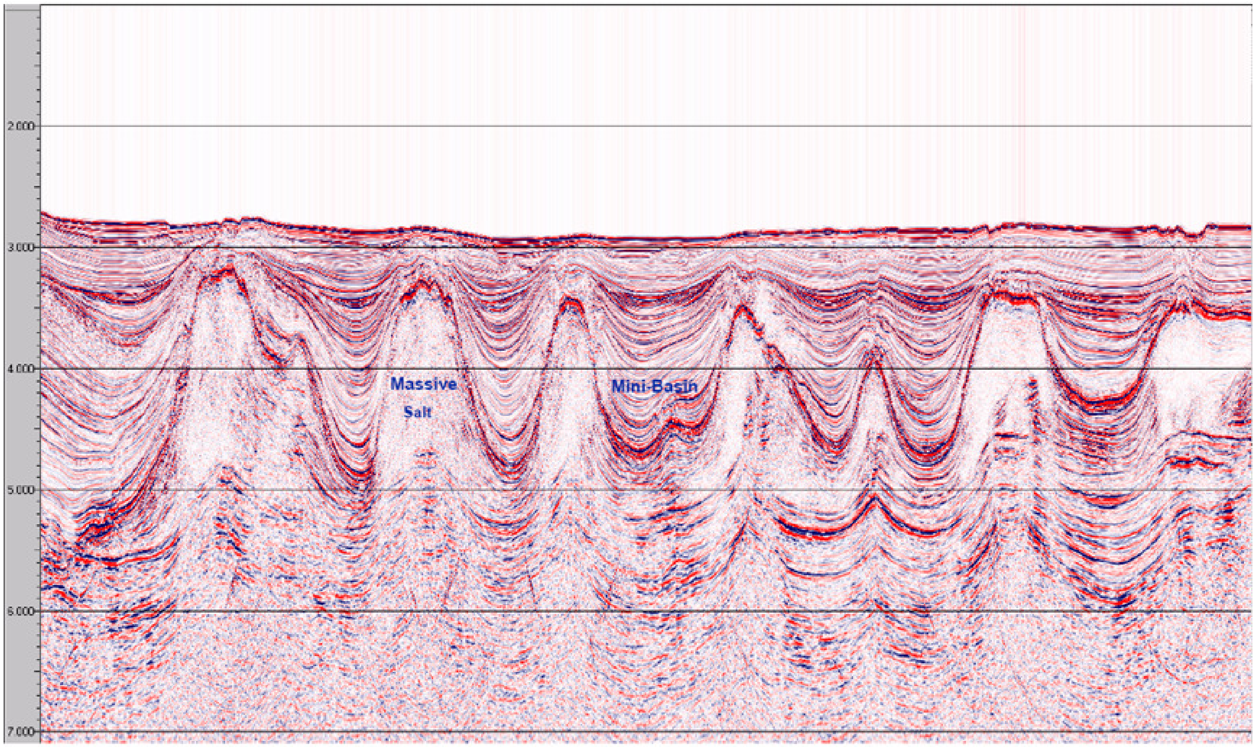


Figure 39. Strike seismic section from the Sao Paulo Plateau of the Santos Basin, Offshore Brazil. Several minibasins can be seen between the salt structures (Fainstein, 2003).

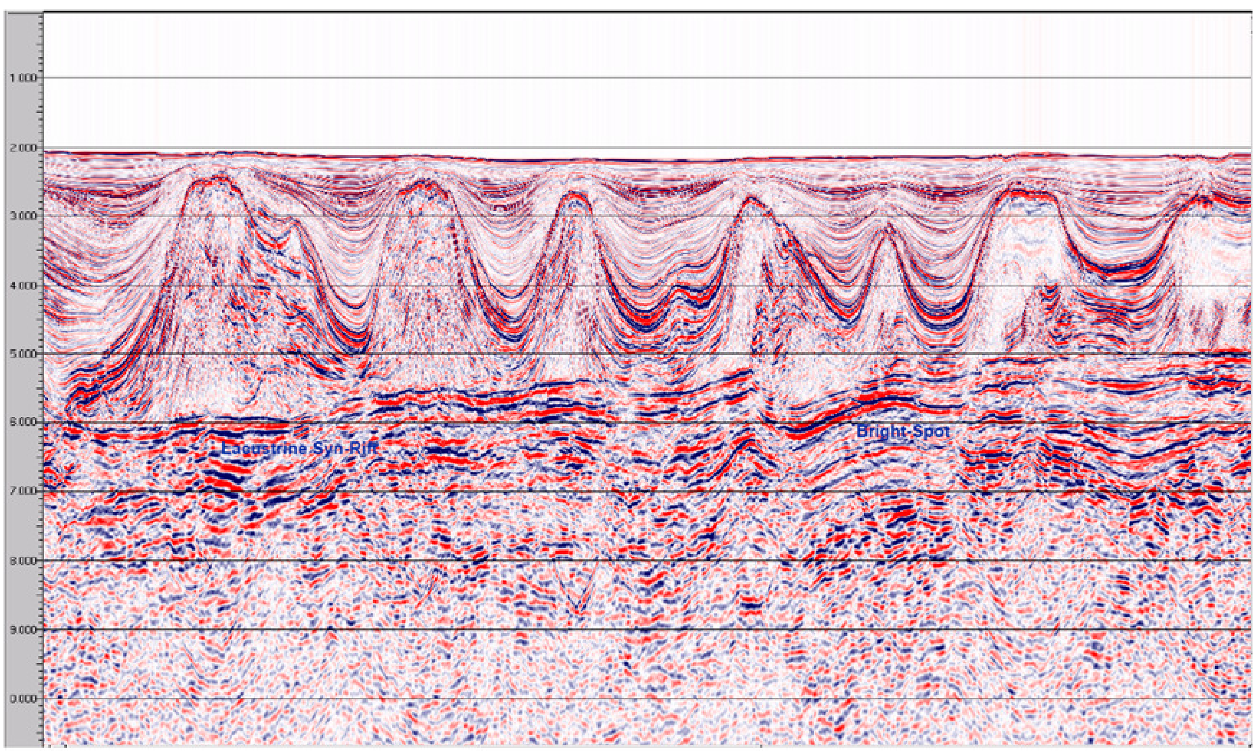


Figure 40. Strike seismic section from the Sao Paulo Plateau of the Santos Basin, Offshore Brazil. Bright spots indicate possible sub-salt plays, beneath the allochthonous salt canopy (Fainstein, 2003).

3.5.4 West Africa

Like Brazil, offshore West Africa has enjoyed tremendous success in recent years from discoveries in Tertiary-age deepwater turbidite sandstone reservoirs. A representative example is Block 34, offshore Angola (Gjelberg, 2003). Figure 41 depicts two paleogeographic maps revealing bypass zones, sandy facies, muddy facies and salt features. Again, the excellent seismic data quality from the young Tertiary-age sediments along with new seismic and successful drilling enables these valuable maps to be created. Similar maps cannot yet be drawn for the Scotian Slope successions because of the incomplete 3D seismic coverage, very low well density and the overall immaturity of exploration.

An example of how far seismic exploration techniques and interpretation have advanced is revealed in Figure 42. Vertical profiles show the amplitude response to sand-prone facies and a 3D seismic time-slice clearly depicts the meandering channels and crevasse splays. Another example of seismic amplitudes and a time-slice map view is shown in Figure 43. When this is all assimilated as in Figure 44, the results are a very well calibrated seismic image of deep water turbidite reservoir sand facies.

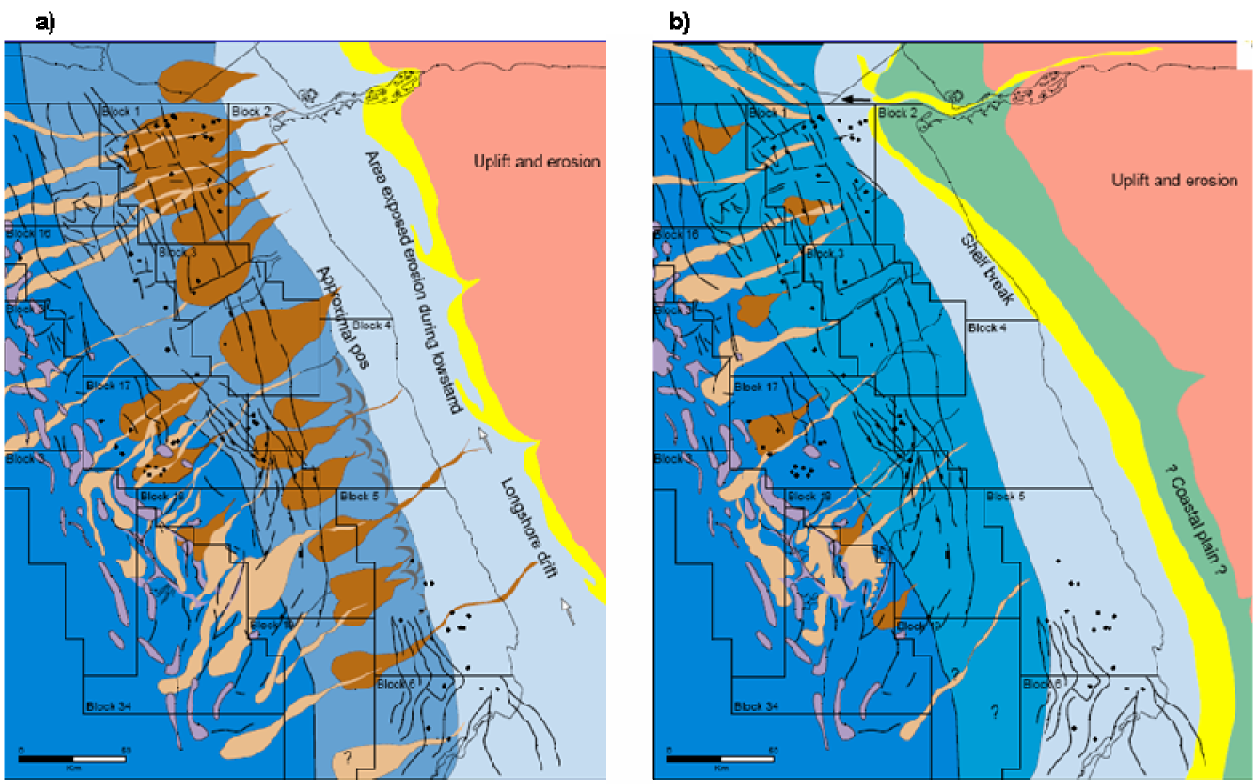


Figure 41. Conceptual paleogeographic maps from the Lower Congo Basin. a) Mid/Late Oligocene; b) Early Miocene (Gjelberg, 2003).

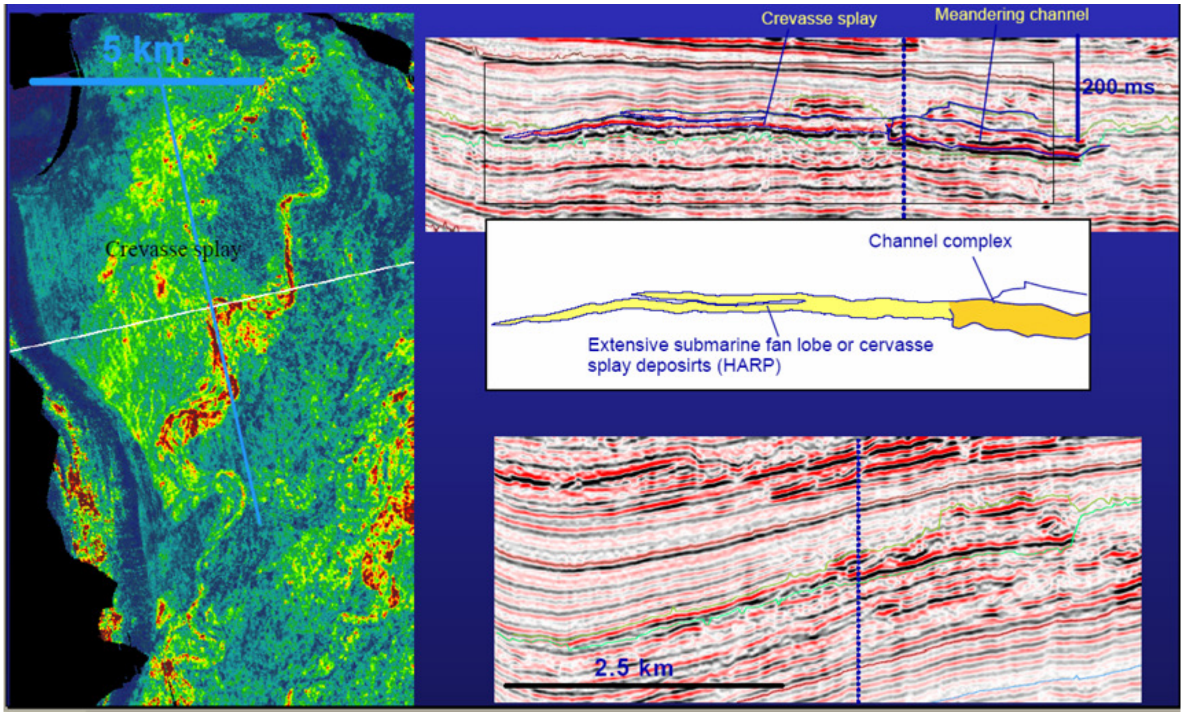


Figure 42. Submarine fan system crevasse splay, from the Lower Congo Basin (Gjelberg, 2003).

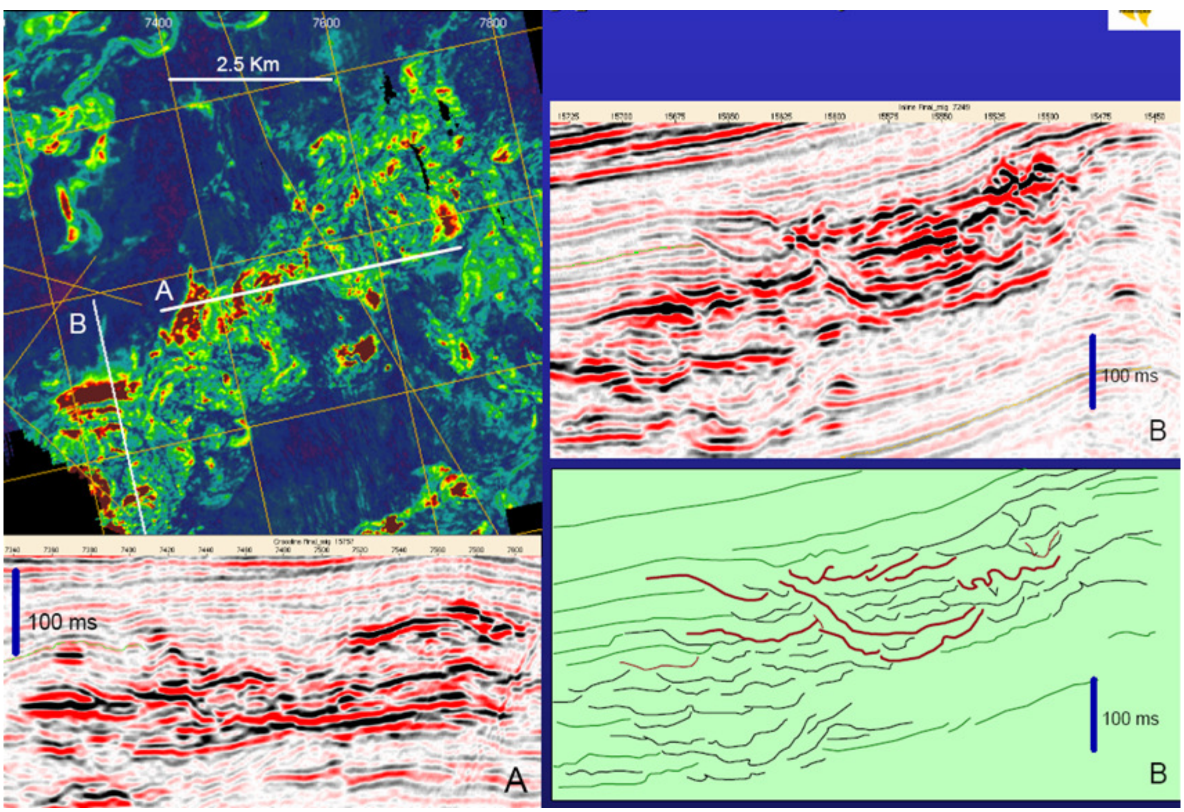


Figure 43. Seismic examples from a deepwater turbidite channel system, in the Lower Congo Basin. This channel system displays complex erosional features and stacked channel sequences (Gjelberg, 2003).

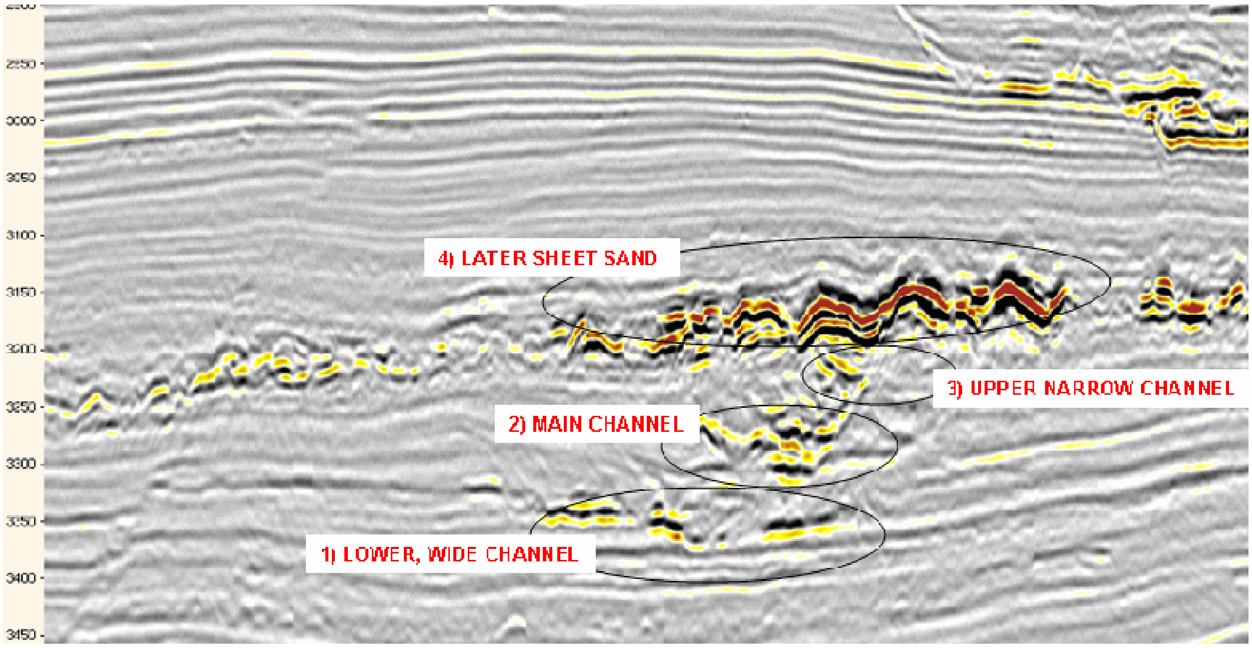


Figure 44. Seismic example from a deepwater turbidite channel system, in the Lower Congo Basin (Rasmussen, 2003).

4.1 Well-Log Cross-Section

As part of this deepwater study, a geological cross-section was created incorporating the post-drill results of all recent and earlier deepwater wells offshore Nova Scotia that were targeting deepwater turbidite sands (Enclosure B). Evangeline H-98 is the only shelf well in the cross-section but was included because it was the key to the Newburn H-23 geological model. The stratigraphic position of the various targets is shown in Figure 45 and illustrates the span of the sampled section. The Western Slope wells concentrated on the Tertiary section while the Central Upper Slope wells focused on the deepwater equivalents of the Cretaceous age shelf discoveries. The 10 cross-section wells are presented in a strike orientation from southwest to northeast:

- Shelburne G-29
- Torbrook C-15
- Shubenacadie H-100
- Evangeline H-98
- Newburn H-23
- Weymouth A-45
- Balvenie B-79
- Annapolis G-24
- Crimson F-81
- Tantallon M-41

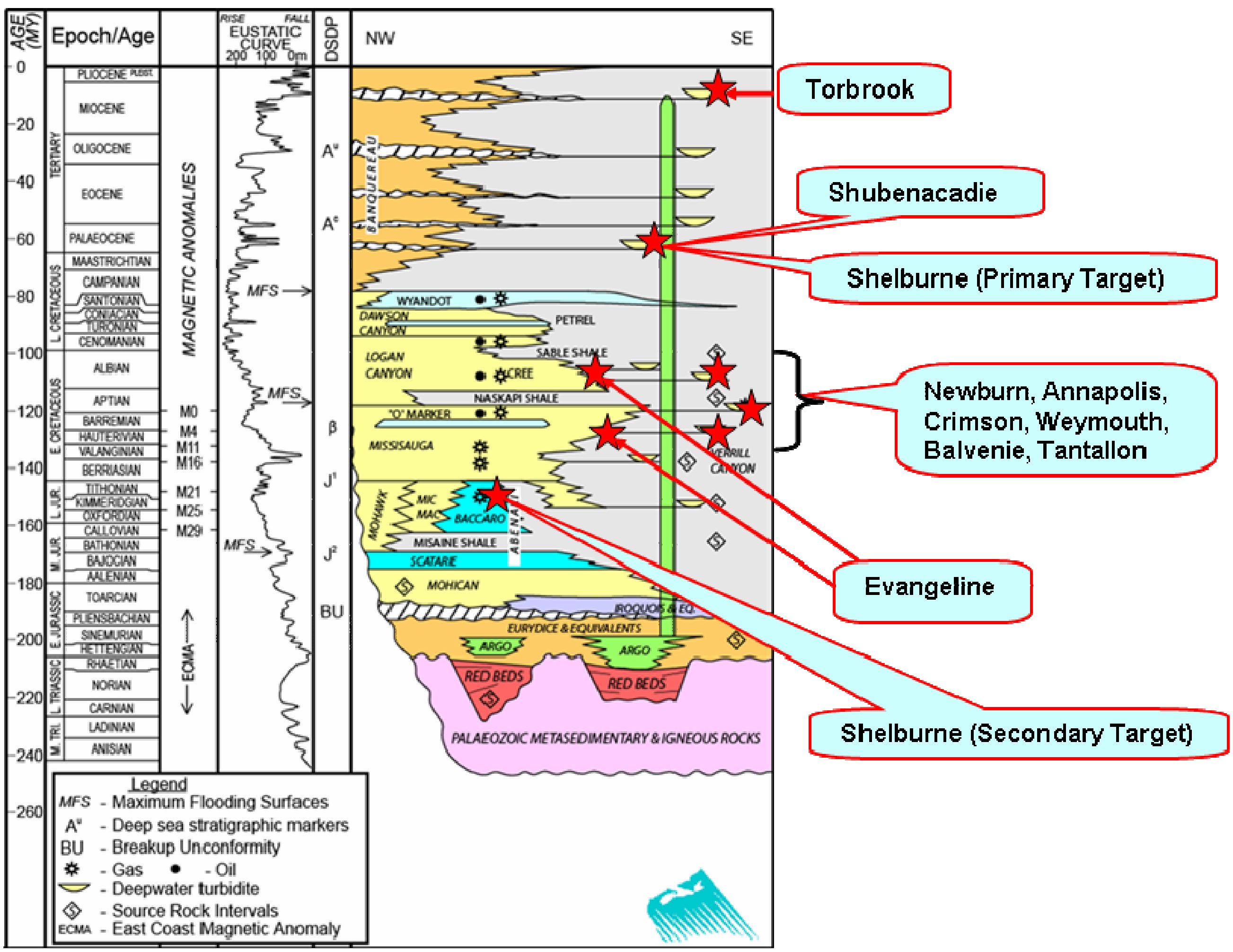


Figure 45. Stratigraphic chart showing target intervals for deepwater wells.

Crimson F-81 was drilled as a follow-up well after the Annapolis G-24 discovery well. Most of the interpreted F, H, L and M reservoir zones for the well do not contain any reservoir quality sands (Marathon, 2005). The tops shown in Track 3 are color coded and represent the following data:

- Black: Lithologic tops (i.e. formation tops, faults etc.)
- Red: Reservoir Zones in Newburn, Annapolis & Crimson*****
- Blue: Biostratigraphic ages
- Green: Biostratigraphic and geologic unconformities

The distance between the wells in the cross-section varies from 9 to 122km apart, thus the correlation of lithologic units can be highly interpretive. Despite this, the Eocene Chalk and the Wyandot formation are generally fair to good geologic picks and so are the two main lithologic correlations on the cross-section. These zones or their equivalents are present in all deepwater wells with the exception of Torbrook and Weymouth. Torbrook reached total depth above the Eocene and thus did not penetrate these horizons, and the zones are not present in Weymouth due to salt intrusion into the Tertiary sediments.

The other correlation lines are geologic ages determined from biostratigraphic analysis. No biostratigraphic data is available for Torbrook and Weymouth. It should be noted that most ages correspond to a depth range which in some instances may be up to several hundred meters, (e.g. in a given well the early Aptian age may range from 4500-5000m) so the depths of these ages are approximate. Some of the key biostratigraphic ages, shown on the section, include:

- Early Albian: Mid Logan Canyon formation Equivalent
- Middle Aptian: Naskapi member Equivalent
- Late Barremian: Upper Missisauga formation Equivalent
- Late Hauterivian: ‘O’ Marker Equivalent

Porous zones are indicated on the cross-section with the porosity symbol (Φ) and sands with net pay are indicated with the “starburst” symbol. The results of each well are reviewed in detail in Chapter 5.

4.2 Overpressure

Defining the top of overpressure is difficult in most deepwater wells due to the very nature that these successions have few if any continuous zones of porous and permeable sediments. In many cases, it was not evident that the well had drilled into overpressure until a kick was experienced. However, using indicators such as sonic and resistivity log trends, cuttings descriptions, mud weight increases in response to increasing connection and trip gas indicating under-balance hole conditions, it is possible to estimate the approximate top of overpressure. For the purpose of this study, top of overpressure is defined as the depth at which the formation or pore pressure begins to exceed “normal” or hydrostatic pressure. In many instances pore pressure increases below the top of overpressure are very gradual, at first, but as drilling progresses rapid pressure increases over a short interval were often experienced (pressure ramp/pressure step). Overpressure was encountered in six of the eleven deepwater wells drilled offshore Nova Scotia, these being: Evangeline H-98, Newburn H-23, Weymouth A-45, Balvenie B-79, Annapolis G-24 and Crimson F-81. For these wells, the approximate depth of top overpressure has been estimated using the available data and is shown in the well results section, Chapter 5.

4.3 Regional Seismic Profile

To date, of the 201 wells in the Scotian Basin, 112 are classified as exploration wells. Of these, 103 are on the Scotian Shelf and nine on the deepwater Scotian Slope. The remaining 89 wells are classified as delineation, production/ development, injector, and relief wells. In this study the shelf well Evangeline H-98 is included with the slope wells. It is a key point as the correlation of shelf stratigraphic units across the shelf break to the slope has proven to be a formidable task despite the extensive seismic coverage.

The regional seismic profile (Enclosure C) is the latest version of a regional seismic reference section. It is a 200 kilometer long composite profile (Figure 46) that starts landward of the Jurassic carbonate bank, runs across the Sable Subbasin including several gas fields, over the shelf break and the slope including the Annapolis and Crimson wells, and out into the salt canopy complex. The profile is composed of the following data sets and used with the kind permission of the respective organizations:

- Canadian Superior Marquis 2D (35km) – Geophysical Service Incorporated
- ExxonMobil Mega-Merge 3D (49km) - ExxonMobil
- ExxonMobil North Triumph 3D (12km) - ExxonMobil
- Marathon 3D (53km) - CGGVeritas
- TGS Regional 2D (45km) – TGS-NOPEC

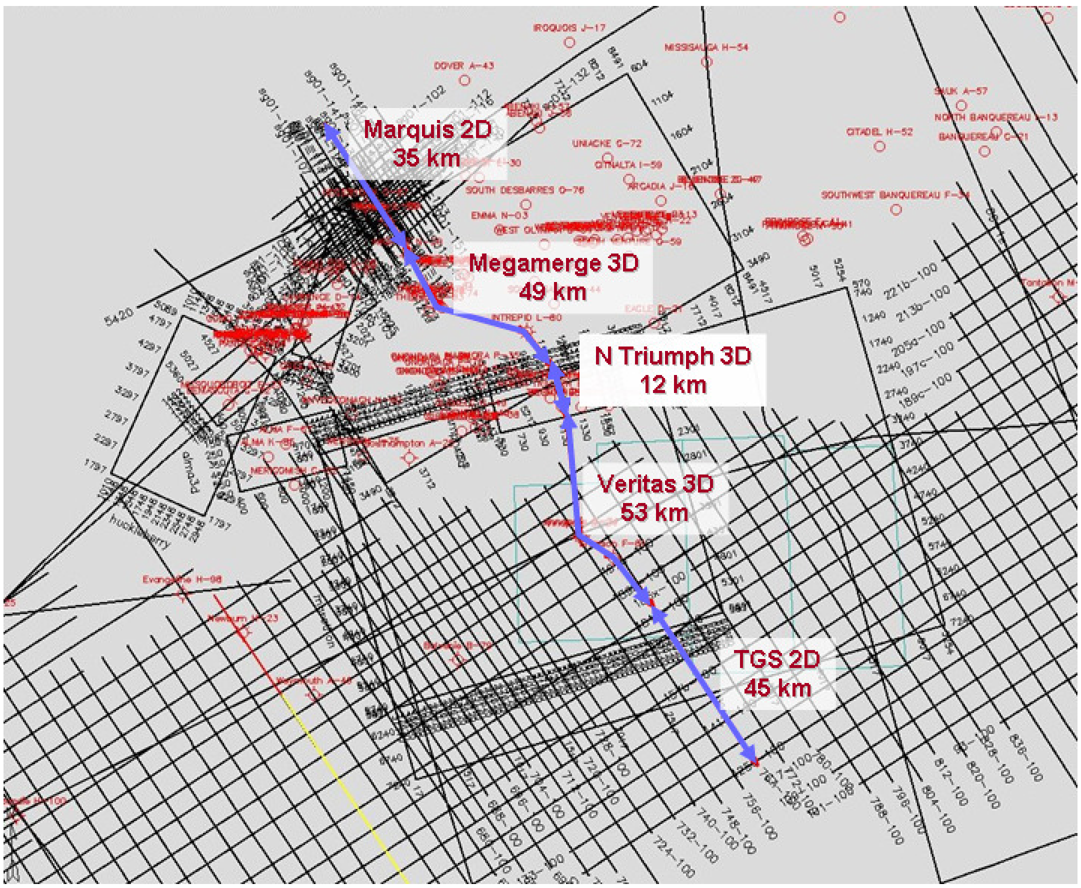


Figure 46. Map of the shelf to slope seismic profile shown in Enclosure C.

The rationale to construct this composite profile was that such a new line would offer a step-back view of the entire Sable Subbasin, permit integration of local features / systems into the regional context, and provide large scale insights on entire Sable delta system from the basin margin to deep ocean - Source to Sink. Some of the seismic markers can be carried across the entire profile while others are limited in their extent. A deep ocean marker for the Top of Jurassic or J1 was tied to older deep crustal oceanic seismic profiles (Ebinger and Tucholke, 1988). Based on analysis of the profile, four informal structural-stratigraphic regimes were recognized:

- Hingeline Margin
- Sable Subbasin Deltaic
- Sable Subbasin Slope
- Salt Canopy Deepwater

From study of the profile, several general observations are noteworthy:

1. The presence of salt is ubiquitous in all regions. It occurs in various forms and structures including pillows and ridges, diapirs and canopies. The respective morphologies give clues on the original pre- and early post-rift basement geometry, original salt distribution and possible volume. There is also a progressive change in structures' morphology over geologic time and distance from the basin margin and paleodelta.

2. Pulses of siliciclastic deposition activated salt motion through time. These and subsequent depositional sequences and facies were strongly influenced by salt. Study of the fields crossed by the profile suggests a possible relationship between the presence of salt and crestal faulting. Structures with underlying and/or adjacent salt have modest gas occurrences whereas those with no salt have significant gas accumulations.

3. The seismic successions beneath the modern middle slope, dominated by parallel reflections, were interpreted by industry as Cretaceous-age deepwater facies, later deformed by salt evacuation. However, biostratigraphic studies from the two deepwater wells in the profile and elsewhere in this area indicate the sediments were deposited in the shallower outer shelf to upper slope setting. This important realization indicates that Cretaceous-age deep water middle and lower slope facies – and reservoirs – may exist further basinward within the deeper water salt province. Potential structural, stratigraphic or combination trap prospects may be located within intrasalt basins or in the subsalt position. Older Jurassic turbidites – deposited in the earlier stages of the Sable Delta's formation – might exist beneath the progradational Cretaceous Upper Slope region. Seismic visualization and recognition of these structures and features will generate profound challenges to exploration.

4.3.1 Hingeline Margin

This regime represents that basin-bounding hingeline area and extends from Km 0 to Km 35. Late Triassic synrift and Early Jurassic post-rift basins (possibly salt-withdrawal) are present and contain possible pre-break up Eurydice formation Late Triassic redbed and lacustrine sediments to early post-break up Mohican formation fluvial sequences. A possible major salt ridge and deep-seated basement high are seen underlying the shallow anticlinal closure drilled by the Kegeshook well. The edge of the Jurassic Abenaki platform margin follows the basement high and it was here that the Marquis well penetrated a porous though wet Jurassic reef facies. The overlying Cretaceous and younger strata are flat-lying and unstructured in this region.

4.3.2 Sable Subbasin Delta

This region is centred on the Sable Subbasin depocentre and extends from Km 35 to Km 85 on the composite profile. The depositional succession is dominated by the Middle Jurassic to Early Cretaceous Sable Delta (MicMac and Missisauga formations). The main structural style is syndepositional growth faulting related to deep salt loading and motion. The resultant anticlinal structures contain most of the economic gas deposits in the Late Jurassic and Early Cretaceous age sediments. The overlying Late Cretaceous and younger strata are essentially unstructured, however, on a broader scale, faulting occurs progressively shallower moving basinward.

On the western edge of this region, there is a thick counter-regional growth sequence of probable Early to Middle Jurassic age. This sequence and the adjacent Migrant well, which marks the onset of growth faulting, both pivot upon an underlying salt diapiric feature. It is also here that the latest Cretaceous to Tertiary section begins down lapping onto the Wyandot marking the beginning of thick progradational sequence. Together, these features infer a deep-seated basement 'step' created by a major fault and a related salt depocentre.

East of Migrant is a pair growth-faulted structures; Adamant and Thebaud. The former is a rollover anticline above deep-seated diapiric structure in footwall. The salt diapir shape beneath Adamant is complex and it also forms part of the footwall and seal for the Thebaud. The Thebaud structure has significant structural relief and unlike Migrant and Adamant does not have leaky crestal faulting. The Thebaud wells provide the last well tie to the Jurassic and from here the Top Jurassic pick is estimated for the remainder of the line.

Between the Thebaud and Intrepid structures lies a possible thick Jurassic-age wedge and clinoform sequence. At least six progradational-like packages are observed that may be interpreted as part of a major Jurassic delta lobe. The sequences prograde basinward and thin up onto the edge of an interpreted deep-seated feature of unknown affinity. There is no evidence of faulting in this succession, and it is capped by a thin wedge of Lower Missisauga strata. The Intrepid rollover anticline is located above the crest of the deep feature and has observed Late Cretaceous reverse faulting. The Tertiary has thickened appreciably at Intrepid location which is on the next growth fault system.

East of Intrepid is the North Triumph field, located at the distal limit of the Cretaceous Sable Delta and only 15km from the present day shelf break. North Triumph is a rollover anticline structure with faulting extending up into the earliest Tertiary. Thick gas pay is present in fluvial and strandplain reservoirs. While there is modest crestal faulting, there is no leakage due to thick top seals. There is no direct evidence of an underlying salt body whose later motion could have accentuated the crestal faulting and subsequent leakage. The eastern part of the North Triumph structure is the footwall for a major down-to-the-basin fault. A thick growth section of Early Cretaceous is present but was not penetrated by the Triumph well. It is at Triumph that the beginning of the modern shelf break occurs, and also, the seafloor canyons and slope channeling complexes that are responsible for poor imaging of the deeper seismic over much of this slope area.

4.3.3 Sable Subbasin Slope

The Sable Subbasin Slope region is the distal depocentre of the delta and extends from Km 85 to Km 130 and occupies the location of the modern Scotian Slope. The original interpretation for Late (?) Jurassic to Late Cretaceous deposition was a deepwater middle to lower slope setting. Structurally, large salt-withdrawal anticlinal features with limited faulting and some erosional events dominate. It is in such structures that the most significant deep water gas discovery was made at Annapolis.

The Tertiary section is well imaged here and many canyon, channel and slump features can be mapped. Below the "Base Tertiary Unconformity", much of this detail is lost and it becomes very difficult to interpret and map any Cretaceous channel fan systems. This has made it very difficult to interpret any sand delivery systems for any of the deep water wells. There are also large growth faults beneath the shelf break that are very poorly imaged.

Seismically, the Cretaceous succession is composed of mostly parallel seismic reflections with limited wedging and growth near salt features. Possible clinoforms are interpreted in the deeper Jurassic section. Biostratigraphic information reveals that outer shelf to upper slope environments dominated in the Cretaceous. This infers that the middle and lower slope facies are located in the salt region located in deeper water seaward.

In the central part of this region, the Annapolis well tested a very large salt-related anticlinal structure having independent four-way closure of Late Cretaceous age. It penetrated most of Early Cretaceous (upper to middle Missisauga with most of overlying Late Cretaceous Logan Canyon strata either eroded or not deposited. Scattered reservoir sands with about a 100m of net pay was discovered, though biostratigraphy of the target zone confirmed an Early Cretaceous outer shelf setting and not a slope environment as interpreted.

At the eastern edge of the region is the Crimson structure. It is an anticlinal feature similar to Annapolis but has three-way closure with the fourth against a salt body. The drilled section was the same as that at Annapolis and being distal found some upper slope facies in basal Logan Canyon. Unfortunately, no reservoir sands were present in target succession that was deposited in an outer shelf location. Both wells, while targeting Cretaceous turbidite sands, instead drilled a section dominated by shales and silts with very little sand content. The succession was variably calcareous that resulted in a section with high reflectivity. The clinoforms in the underlying Jurassic age strata might represent deepwater depositional facies in the area.

4.3.4 Salt Canopy

The Salt Canopy regime represents the outer limits of deposition related to the Sable Delta and is located from Km 130 to Km 194 on the modern middle to lower slope and abyssal plain.

This region was formed through salt withdrawal and is dominated by allochthonous salt canopies with Tertiary to possibly Cretaceous age mini-basins. The salt motion was likely multiphase with motion initiated possibly in the Middle Jurassic, with some salt bodies still active and near the sea floor. The subsalt section, which is mostly Cretaceous, is very noisy that makes it very difficult to visualize any stratigraphic and structural information. However, it may well be that it is here, in this undrilled region with water depths exceeding 2000m, that Cretaceous age deep water sand-rich turbidite successions were deposited.

The Salt Canopy region is dominated by allochthonous salt features with very poor subsalt imaging especially in this 2D seismic dataset. The Weymouth well, located further to the west, drilled a similar salt intrusive feature but did not encounter any Cretaceous age subsalt sands. The continuation of the Top Jurassic marker beyond the shelf is highly speculative. However, the landward projection of the Top Jurassic pick from earlier deepwater seismic profiles (Ebinger and Tucholke, 1988) implies there is the potential for a thick prospective section.

5. WELL EVALUATIONS

The ten deepwater wells studied for this report (excluding Annapolis B-24) are presented in chronological order of drilling to illustrate the progression of exploration concepts and techniques applied. The discussion for each well follows the same format and addresses the following questions and issues related to that specific well.

Pre-Drill Objectives and Concepts

- What were the pre-drill concepts and objectives?
- What data/information were these concepts based on?

Post-Drill Results

- What were the drilling results?
- How is the seismic interpretation affected?
- What do biostratigraphy, paleo-environment and geochemistry data reveal?
- Are there regional exploration implications?

Well Operations

- Were there operational problems that compromised the well's objectives?

Risk and Assessment

- Does this affect the prospect and/or play risking?
- Does this impact the Board's resource assessment?

Recent ADW (Authority to Drill a Well) submissions for each well contain a large amount of information on the pre-drill interpretation and concepts. Files on older well applications contained limited technical information, hence pre-drill expectations are less well detail.

Data on each well used in this report is limited to released public information such as Well History Reports (following the requisite period of confidentiality), and public statements and presentations by the operators. Any confidential data used in this report is sourced from the respective operators and is used with permission. All ADWs remain confidential for an indefinite period and are not publicly available.

5.1 Shell Shubenacadie H-100 (1982/83)

Shell was the first operator to drill in deepwater offshore Nova Scotia using the Sedco 709 semisubmersible rig. Shubenacadie H-100 was located in 1476.5 metres of water and spudded on November 5, 1982 with rig release on February 12, 1983 (Enclosure A).

5.1.1 Objectives and Concepts

The stratigraphic level and primary target was an interpreted Lower Tertiary turbidite fan with a secondary objective being a younger Miocene bright spot (Shell, 1983) (Figure 47).

The Base Tertiary time map (Figure 48) shows the location on a southeasterly plunging high. The seismic lines AA and BB (Figures 49 & 50) show the sub-orange marker interpreted fan, and if the time map was converted to depth there probably would be a fan-shaped anomaly. The primary target was an interpreted Eocene turbidite fan deposit on the paleoslope (orange marker), and the secondary target was a shallower (Miocene) seismic amplitude anomaly below the yellow marker.

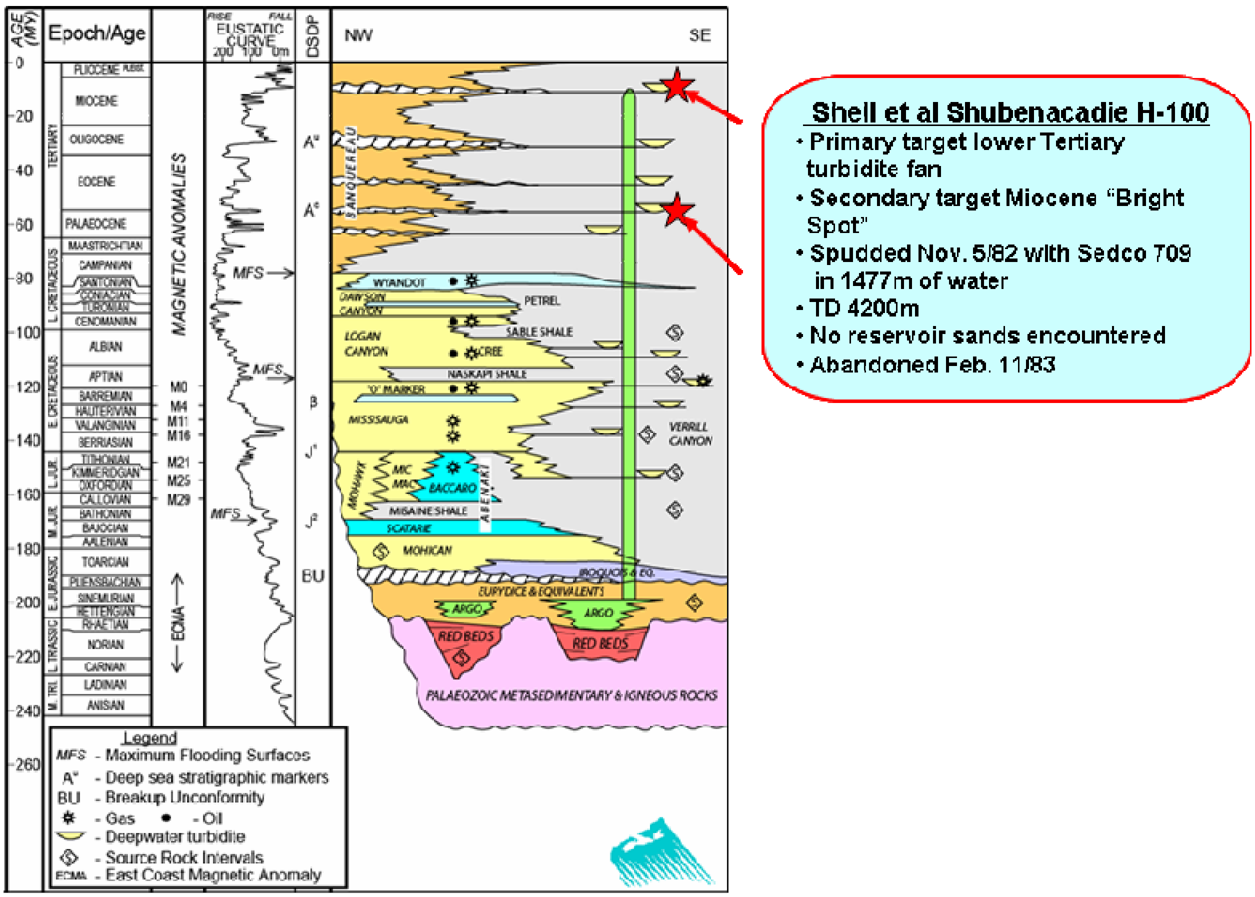


Figure 47. Stratigraphic chart showing target interval for Shubenacadie H-100.

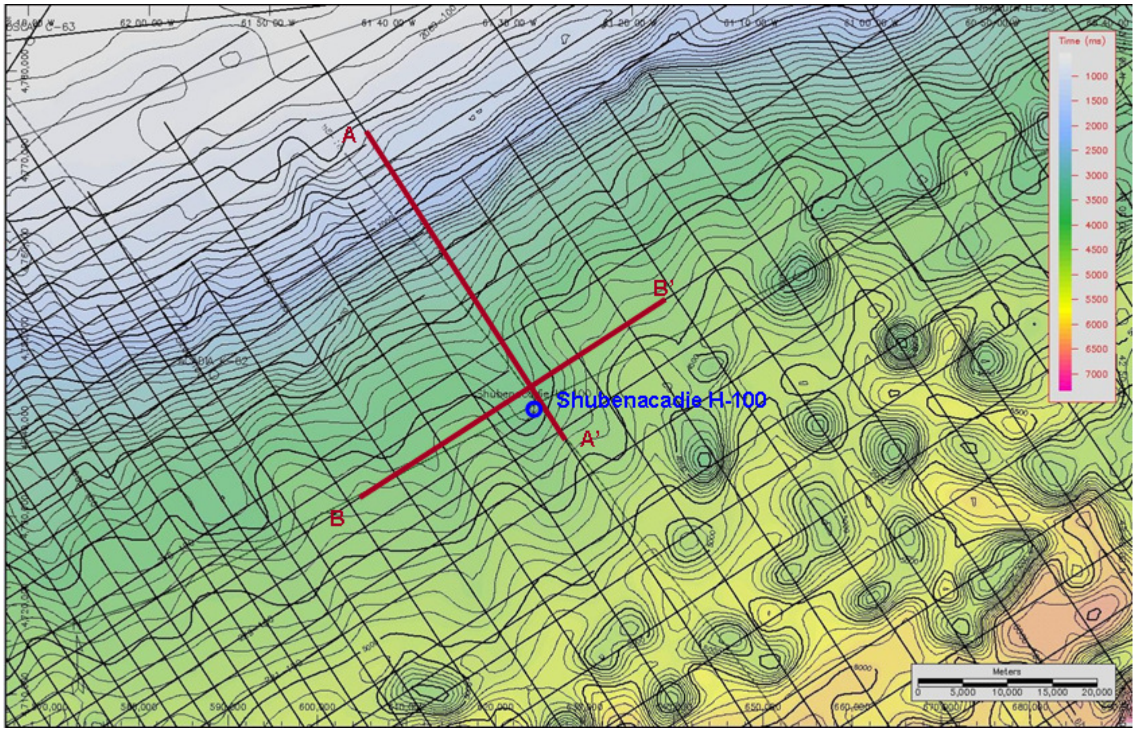


Figure 48. Map showing regional 2-D seismic near Shubenacadie H-100, and the depth to Base Tertiary. Line A-A' is shown in Fig. 49; B-B' is shown in Fig. 50.

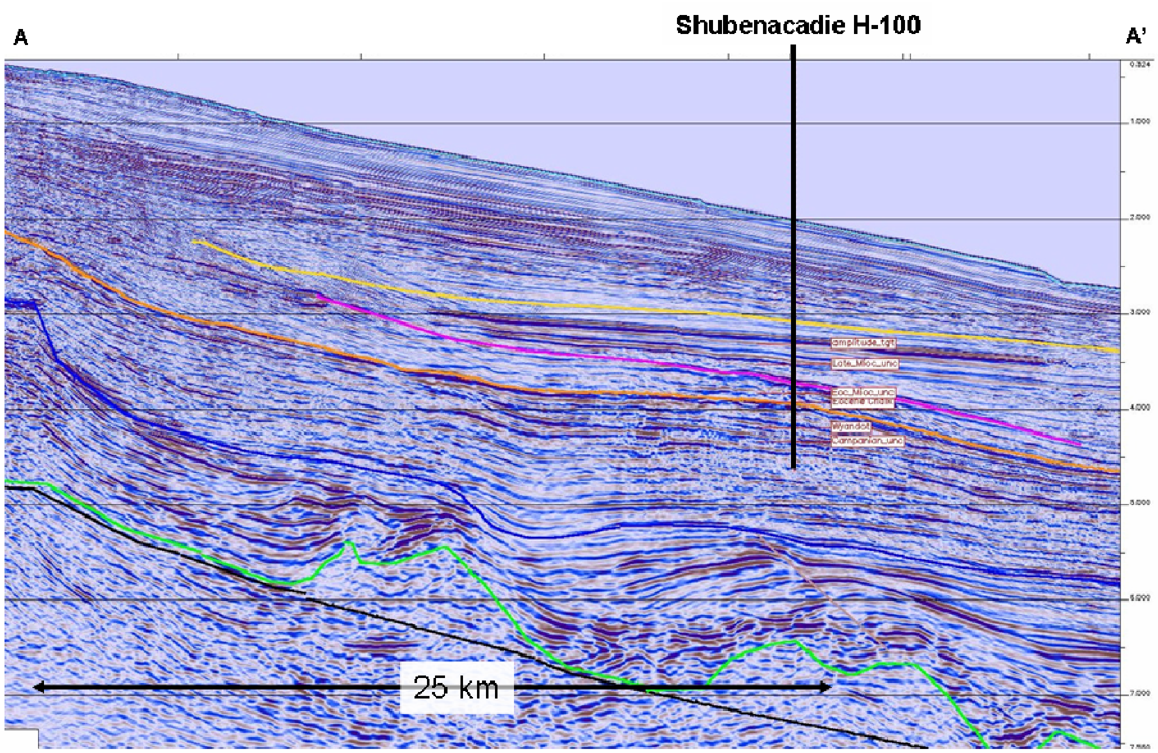


Figure 49. Regional 2-D seismic dip line through Shubenacadie H-100. The targets for this well included the amplitude anomaly at 2.3 seconds (TWT) and the thickened mound below the orange horizon, interpreted as a possible turbidite. Data courtesy of TGS-NOPEC.

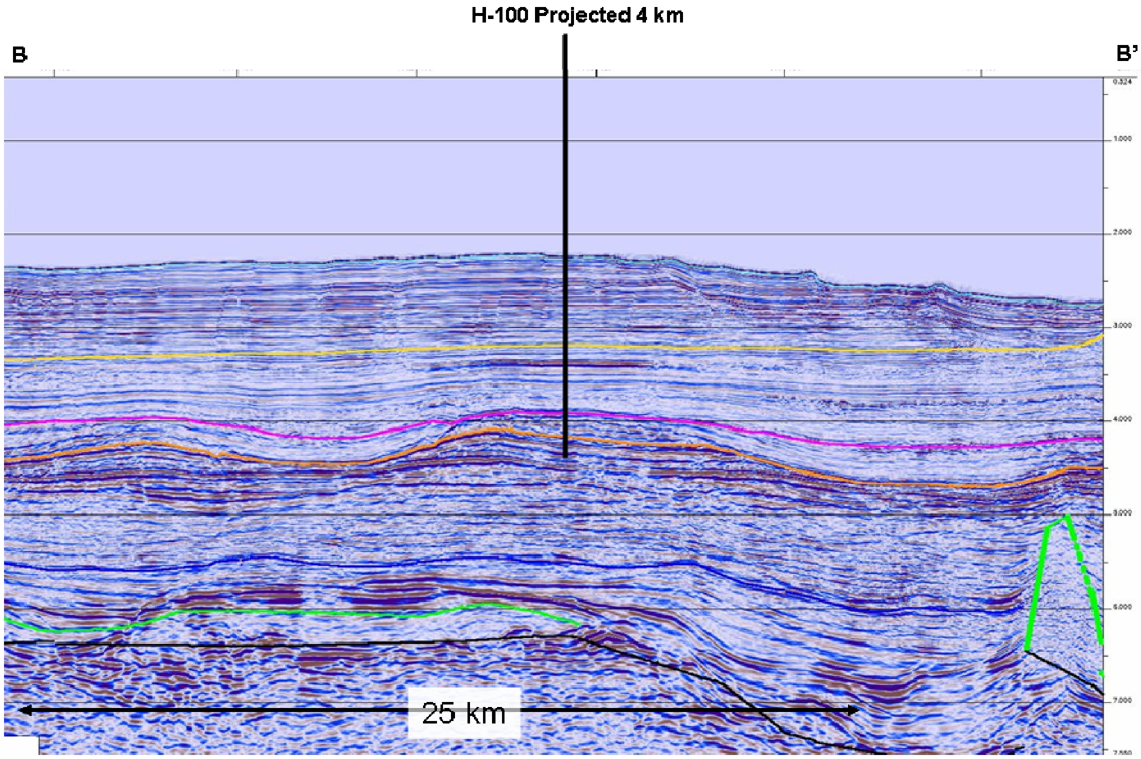


Figure 50. Regional 2-D seismic strike line near Shubenacadie H-100. The deeper target (orange) is an erosional remnant, bounded by two channels in this view, not a mounded turbidite deposit. Data courtesy of TGS-NOPEC.

5.1.2 Results

Drilling

The well was drilled to an FTD of 4200m MD reaching the Middle Cenomanian upper Logan Canyon equivalent, although the planned TD was 4374m (Enclosure B).

The prognosed Miocene bright spot secondary target was encountered at 2636m MD and consisted of a 25m tight, very fine-grained, silty sandstone with no shows (Figure 51). The age of this sand is believed to be Early Pliocene rather than Miocene. Unfortunately, the sonic and density log readings across this zone are questionable due to poor hole conditions (washout). However, the resistivity logs, sidewall cores and cuttings all indicate that the zone is tight.

The well's primary target zone consisted of early Tertiary to Late Cretaceous age shale, tight limestone and marl (Figure 52). No reservoir quality sands were encountered in the well. Four conventional cores were cut at the following depths (Figures 51 & 52):

- Core #1: 2597.8– 2616.1m, No Recovery
- Core #2: 3243.4– 3261.7m, Recovered 3.9m
- Core #3: 3554.6– 3572.9m, Recovered 2.0m
- Core #4: 3650.3– 3659.1m, Recovered 6.8m

Core #1, cut approximately 40m above the bright spot target, had no recovery. A portion of core #4 is shown in Figure 53. The section consists of interbedded calcareous shale, marl and limestone. Biostratigraphic analysis suggests that these sediments were deposited in lower bathyal conditions (water depth 1000–4000m); however, it was noted that the interpreted water depth was somewhat uncertain (Thomas, 2000).

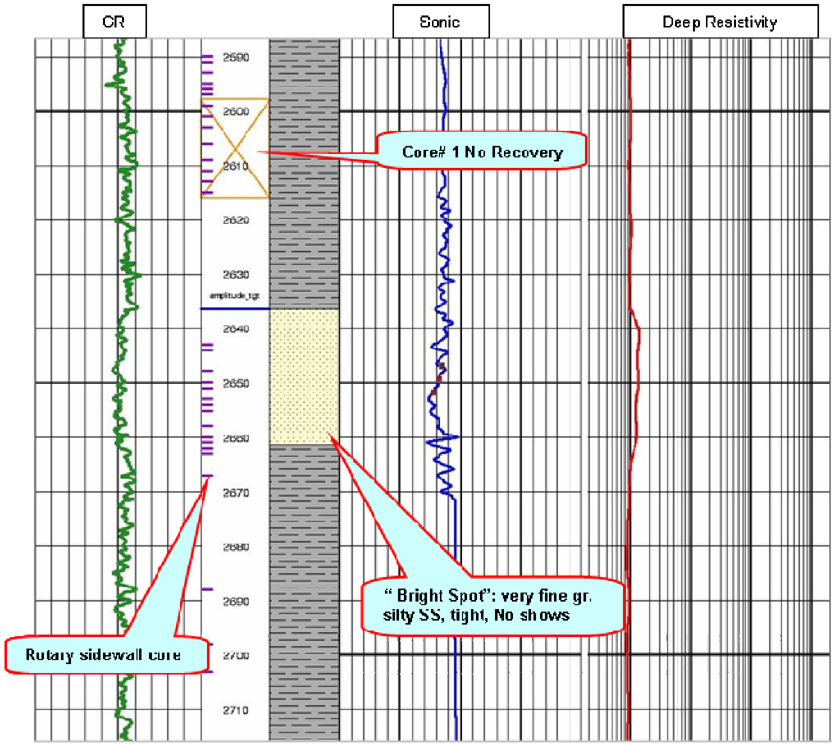


Figure 51. Shubenacadie H-100: Well logs from the Miocene amplitude target. The target corresponds to fine-grained silty sandstone (tight).

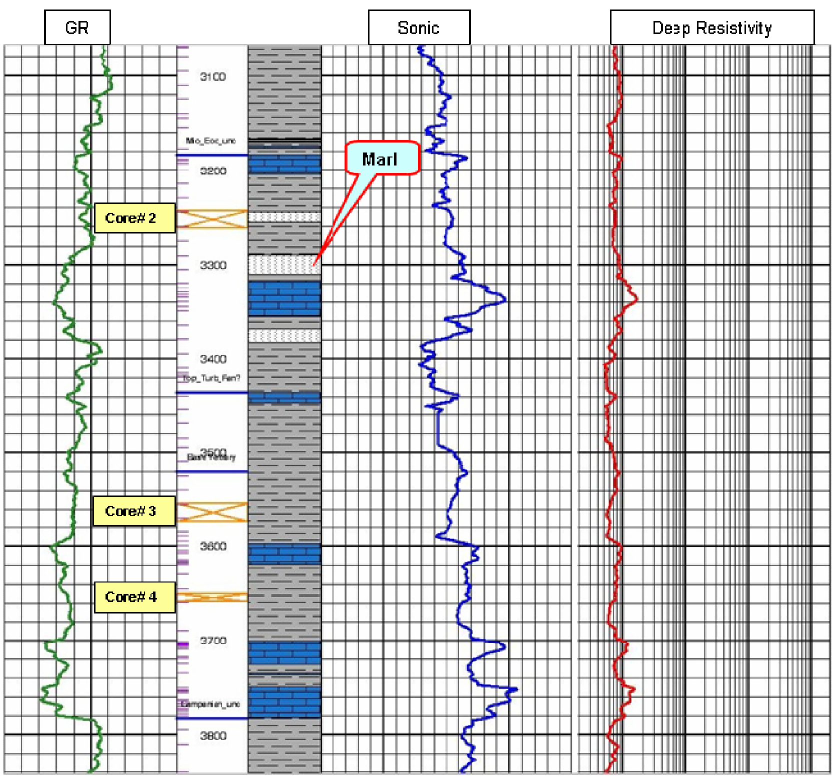


Figure 52. Shubenacadie H-100: Well logs from the turbidite target. The section consists of shale, limestone and marl.

Figure 53. Shubenacadie H-100: Portion of Core #4 (3650.3 – 3659.1 m, 6.8 m recovered).

The final section of the well was drilled with mud weights from 1200–1440 Kg/m^3 in response to increasing trip and connection gas, suggesting that the start of overpressure begins above 3475m. The mud loggers state that the top of overpressure occurred between 2670–2900m based on pressure plots derived from log data. However, the log data used to generate these plots is, in some cases, of questionable quality due to poor hole conditions. In addition, the lack of porous and permeable zones in the well further complicates overpressure determination.

Seismic Interpretation

It is believed that the well pre-drill interpretation was based on the then-successful North Sea analogues. A simplified explanation of the North Sea method was to look for mounded seismic morphologies where mapping indicated a lobate form; then, within this define the portion of the mounded seismic facies that may contain channelized sands. The use of AVO, flat spots and amplitudes, if present, could high-grade the prospect.

The Base Tertiary time map (Figure 48) was created from the recent 2D regional seismic program acquired by TGS-NOPEC during 1999-2000. This map shows a "wavy" pattern to this horizon caused by channels cutting down across the slope. This supports the interpretation that the previously interpreted Shubenacadie fan is in fact a subcrop remnant below the Base Tertiary (Paleocene to Eocene) unconformity. The Shubenacadie structure is one of the larger remnants separating two divergent channel-dominated areas, which contributed to it resembling a constructional fan on the older seismic.

A "low" created by withdrawal of deeper salt at tie line 245 may cause the slight dip reversal or flattening evident on the Base Tertiary (orange) marker up-dip from the well location (Figure 49). In strike profile through the well and at this location, truncations of parallel reflections below the Base Tertiary can be observed, indicating that the Shubenacadie structure is an erosional remnant separating two channels (Figure 50). Erosion east of Shubenacadie was widespread and not confined to a narrow channel. The well's alternating shale/marl/limestone lithologies are indicative of the progradational margin's 'background' stratigraphic succession and are identical to the Shelburne G-29 results (see Section 5.3.2).

In Exxon's paper on submarine fan seismic detection, Mitchum (1984) noted that one of the pitfalls was mapping erosional remnants. The clue was the recognition of sub-unconformity reflection truncation within the predicted "fan". In the synthetic seismic tie to the well and adjacent seismic data (Figure 54), there is generally good correlation between the well and the 2D data allowing the major seismic events to be identified. Many of the seismic reflections appear to result from varying calcite content in the shales. This is supported by the observation that the shales within the recovered cores were highly calcareous thereby affecting the log responses and consequently the synthetic. This relationship was also evident in the similar successions penetrated by the Shubenacadie and Weymouth wells.

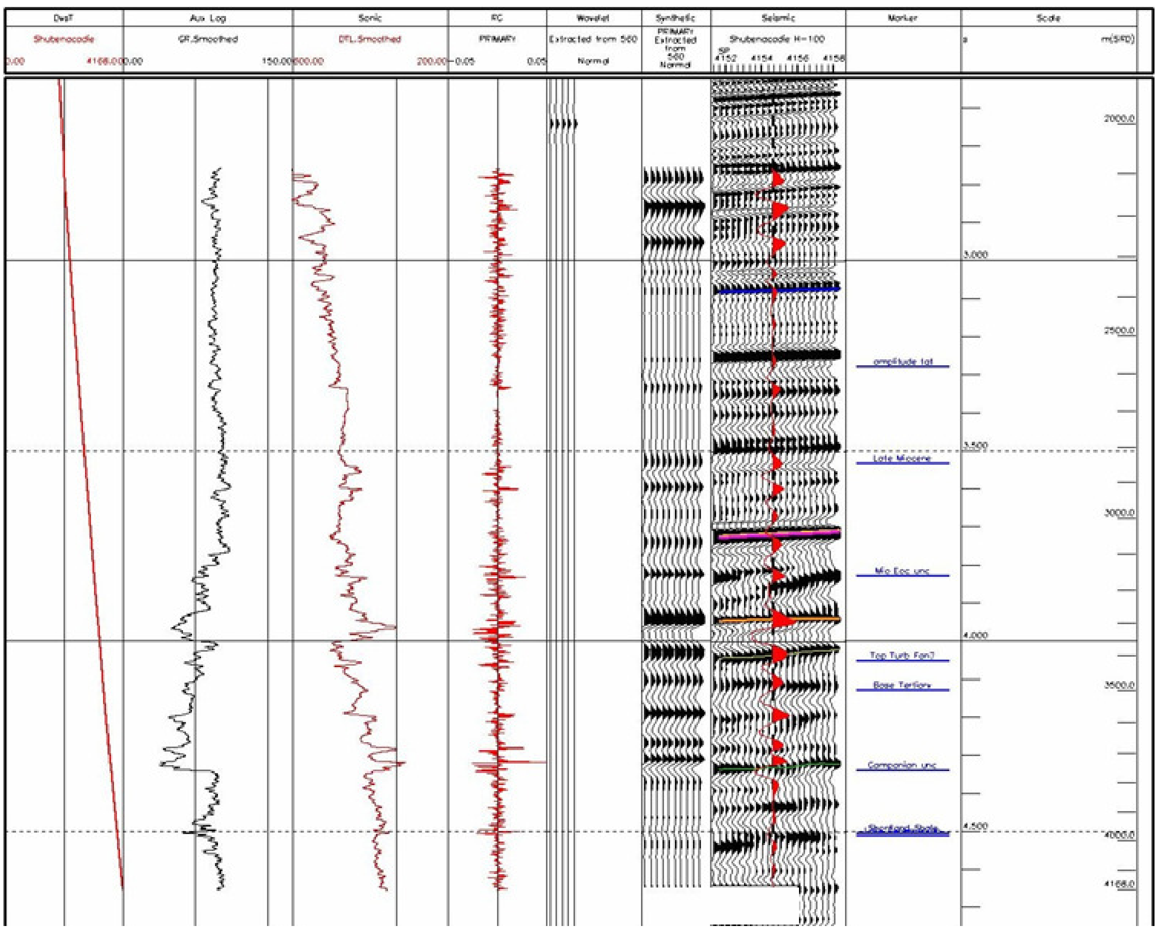


Figure 54. Shubenacadie H-100: Synthetic seismic.

Biostratigraphy

Within the Tertiary succession (Banquereau formation), the Shubenacadie H-100 well was drilled through two unconformities (Enclosures D, E). The youngest represents a 4 Ma time gap in the Late Miocene (Tortonian) that is not seen in the similarly located Shelburne G-29 well. A more significant Miocene unconformity appears to have initiated in the upper Early Miocene (Burdigalian) resulting in the removal of Middle Eocene to Oligocene strata creating an approximately 23 Ma time gap. Like the Shelburne well, the interpreted Shubenacadie submarine fan complex was actually an erosional remnant. The sediments encountered in the well were composed of Middle Paleocene to Late Campanian calcareous shales with minor marls and chalks; the latter creating the internal reflections observed on seismic profiles. The so-called 'Base Fan' reflector corresponded with a condensed or missing section of Middle to Early Campanian strata. Dip logs of the targeted section and enclosing strata confirm the erosional nature of the feature. At total depth, the well was in Middle Cenomanian shales.

Paleoenvironment

Biostratigraphic analyses were completed for the well by Thomas (2000), Fensome (2000) and Robertson Research (2001), with all in general agreement on the paleoenvironmental interpretation of the Late Miocene to Pliocene strata recording deposition in an upper slope environment. Fauna in the underlying Early Eocene to Early Paleocene strata record upper to deeper middle slope environments suggesting an overall transgressive succession. The remaining Late Cretaceous (Maastrichtian to Middle Cenomanian) sequence of shales and minor carbonates is representative of persistent deposition on the upper slope.

Geochemistry

Vitrinite reflectance (Ro) analysis of dispersed organic material from 10 selected cuttings samples was completed by the Geological Survey of Canada (Avery, 1999a). While the organic matter type was not noted in this report, presumably it is the typical Type IIA-B to Type III kerogen types (mixed to woody-herbaceous) common in the ubiquitous Verrill Canyon formation and equivalents. The data indicate that the Tertiary and uppermost Cretaceous strata are immature to marginally mature. The remaining Late Cretaceous section ranges from marginally mature to early mature (oil-generating window). Consequently, sediments in the lowest part of the well have the potential to generating liquid hydrocarbons.

Depth (m)	Formation	Age	Vitrinite Reflection (% Ro)	Maturity for oil generation
1477	Sea Floor	Recent	(0.21)	n/a
3350	Banquereau	Ypresian (E. Eoc.)	0.4	immature approaching maturity
3980	Dawson Cyn. Eq.	E. Turonian (L. Cret.)	0.5	marginally mature
4200 (TD)	Logan Cyn. Eq.	M. Cenomanian) (L. Cret.)	0.55	within oil window

Table 2. Thermal maturation levels for the Shubenacadie H-100 well (from Avery, 1999a). Note that the seafloor value in brackets was calculated from the derived / extrapolated Ro slope of 0.153 log Ro/km.

Exploration Implications

The main exploration implication, also confirmed in the Shelburne G-29 well, is the Tertiary fan play was not tested because an erosional remnant was mistaken for a submarine fan. However, it remains somewhat discouraging that the background regional facies did not include any coarse clastics. The Tertiary section in this area appears relatively immature for the generation of hydrocarbons. Therefore migration from deeper sources must be invoked which adds to the overall risk (P.K. Mukhopadhyay, 2002 in Kidston et al., 2002) Its unfortunate the well was not drilled to the more mature lower Cretaceous and Jurassic section.

5.1.3 Well Operations

It was estimated pre-spud that it would take 48 days to drill the Shubenacadie well (Well History Report, 1983). The well encountered significant delays and required 105 days to drill and abandon including mobilization and de-mobilization time (Figure 55) (Shell, 1983). The increase in drilling days was due to a stuck drill string at 3554m MD resulting in a back off and sidetrack. In total, 22.6 days were lost stuck, fishing or sidetracking. A considerable amount of time was also lost due to mechanical downtime (8 days) and hole conditioning (approx. 10 days) mainly due to reactive (swelling) shales caused by the water-based drilling fluid.

5.1.4 Risk and Assessment

Shubenacadie lies in the Western Upper Slope play area of the Board's assessment where the dominant play type is pre-Tertiary anticlinal features and tilted fault blocks. The Tertiary slope fans were a secondary play and not assessed, hence the results of this well have little to no impact at this time.

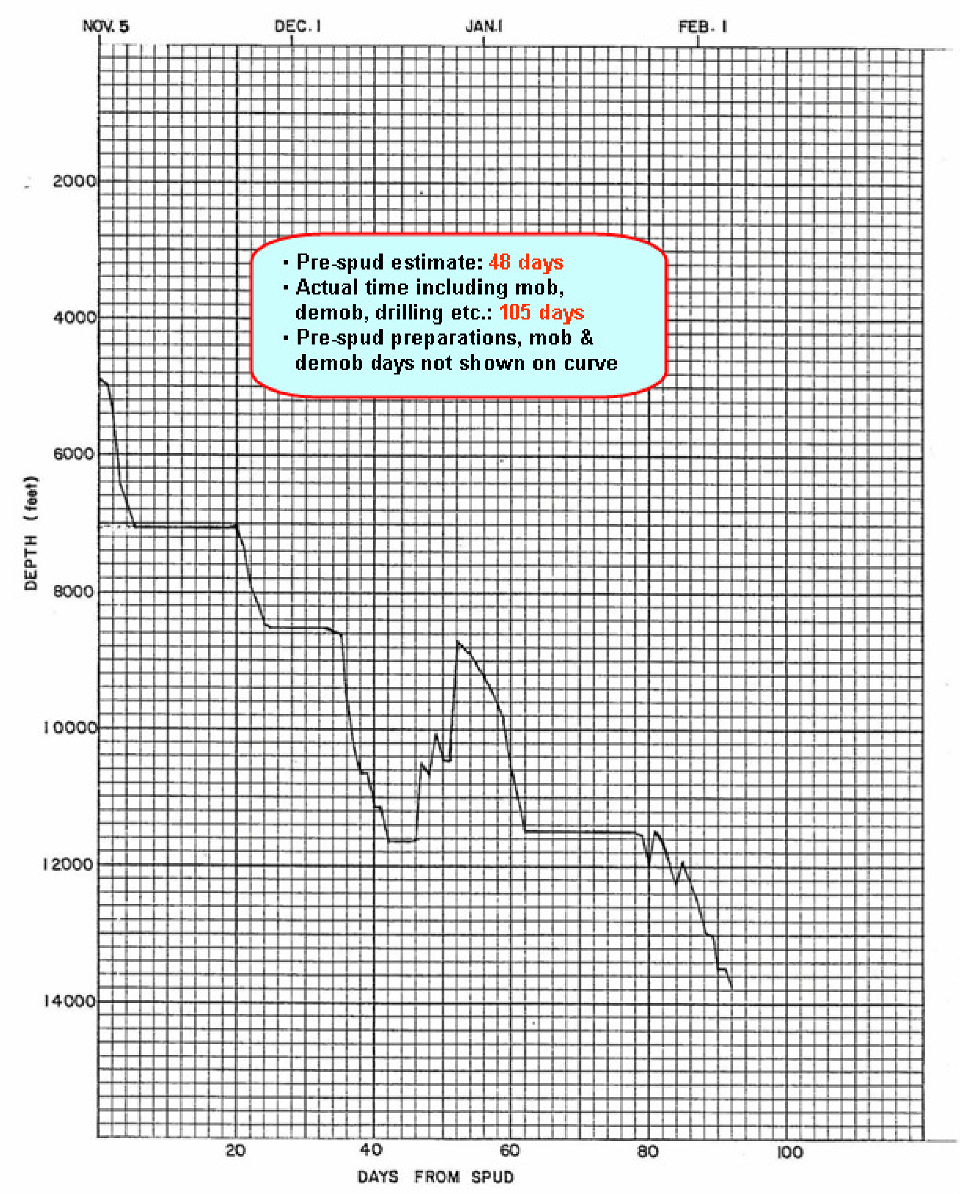


Figure 55. Shubenacadie H-100: Time vs. depth curve (actual).

5.2 Husky Evangeline H-98 (1984)

The Evangeline well was drilled at the southwest limit of the Sable Subbasin on the shelf in 174 metres of water using the Bow Drill II and III semi-submersible drill rigs (Enclosure A). The well was spudded on March 27th, 1984 and the rig released on November 1, 1984. Although not usually included in deepwater analyses, the H-98 well was drilled in front of the Jurassic carbonate bank margin and is situated only 17km landward of Chevron's 2002 Newburn H-23 well. Therefore, it is an important control well for the deepwater slope.

5.2.1 Objectives and Concepts

The primary reservoir targets were shallow marine/deltaic sands of the Logan Canyon (anticipated at depths of 3000-4000m) and deltaic sands of the Missisauga formation (expected in the 4000-5000m range). These formations have been the primary exploration and production targets in the Sable paleodelta (Figure 56). The well was drilled on a fault-dependent closure on the downside of a down-to-basin listric fault (Husky, 1985). The location map (Figure 57) shows the proximity of the well to the other slope wells and the current seismic coverage.

Figures 58 is vintage seismic lines across the anomaly that looks similar to a more recent profile (Figure 59). Mapped closure was 29.1km^2 at the Logan Canyon level and 47.7km^2 at the Naskapi level. Closure was expected through the entire deeper Missisauga section.

This play was based on mapping of 2D data and was analogous to the previous roll-over anticline successes in the Sable area. The well was drilled to test the seaward limit of the delta front sands realizing the prodelta facies would be encountered through most of the section. The structure existed but the existence of reservoir facies and fault leakage were inherent risks.

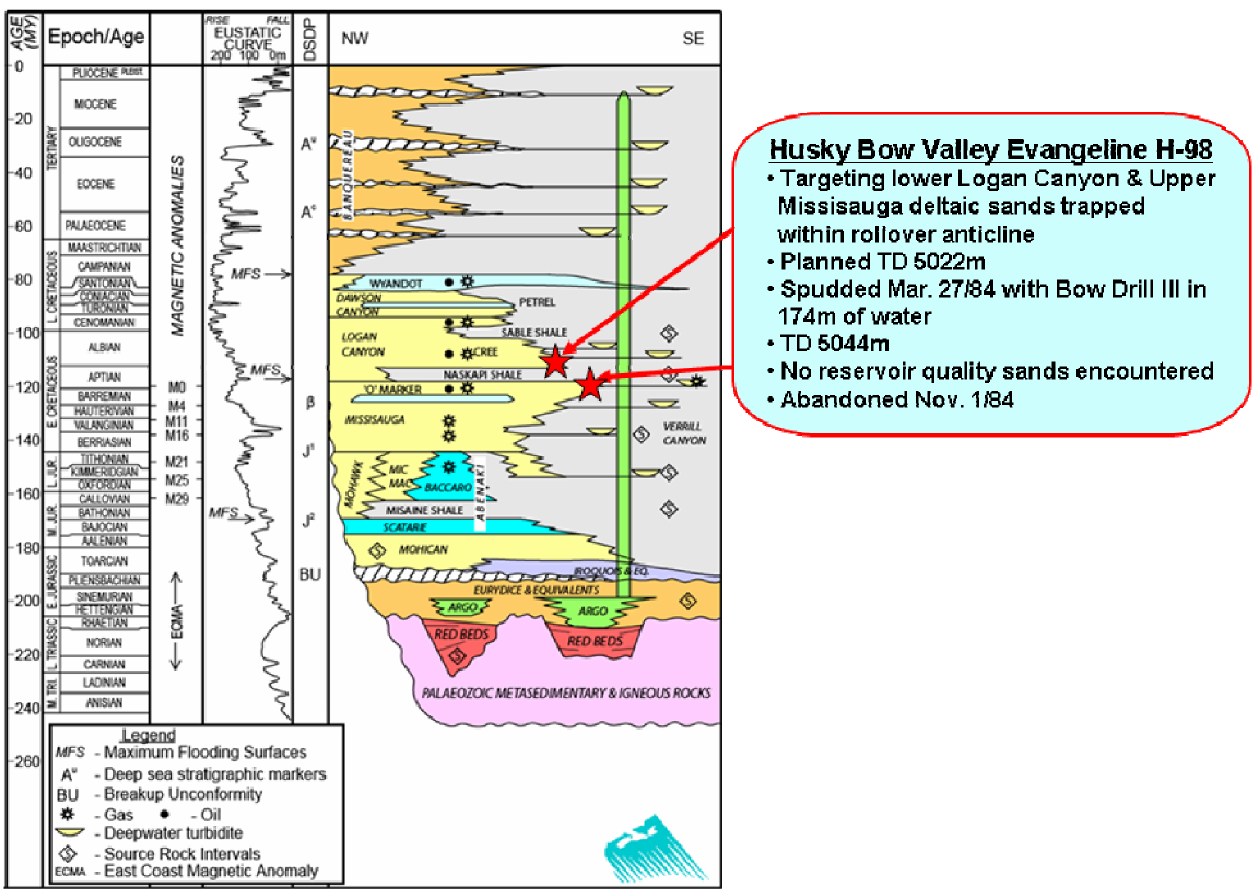


Figure 56. Stratigraphic chart showing target intervals for Evangeline H-98.

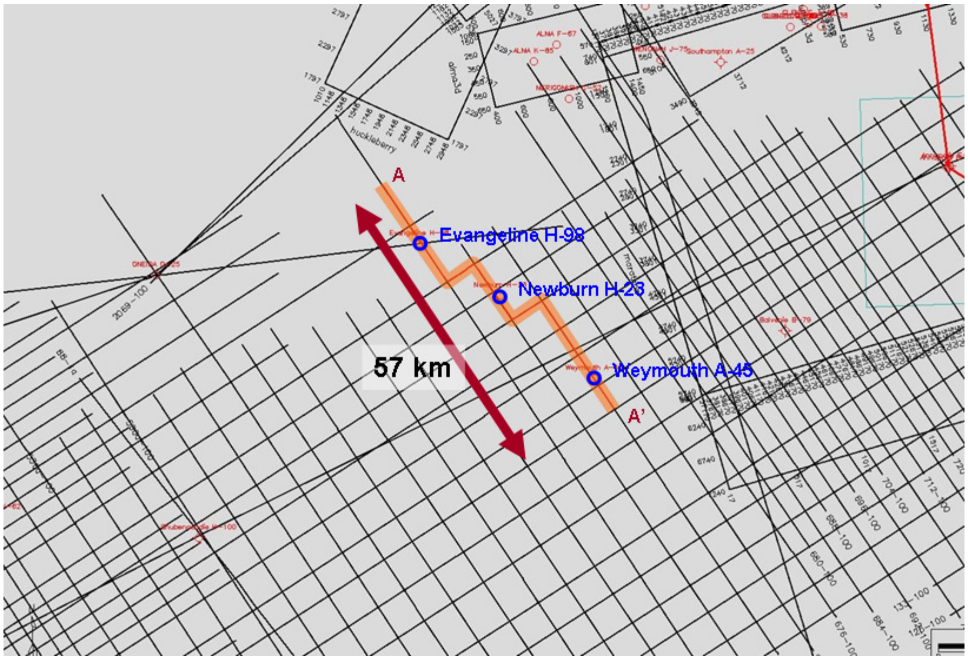


Figure 57. Regional 2D seismic through Evangeline H-98, Newburn H-23, and Weymouth A-45. Line A-A' is shown in Figure 62.

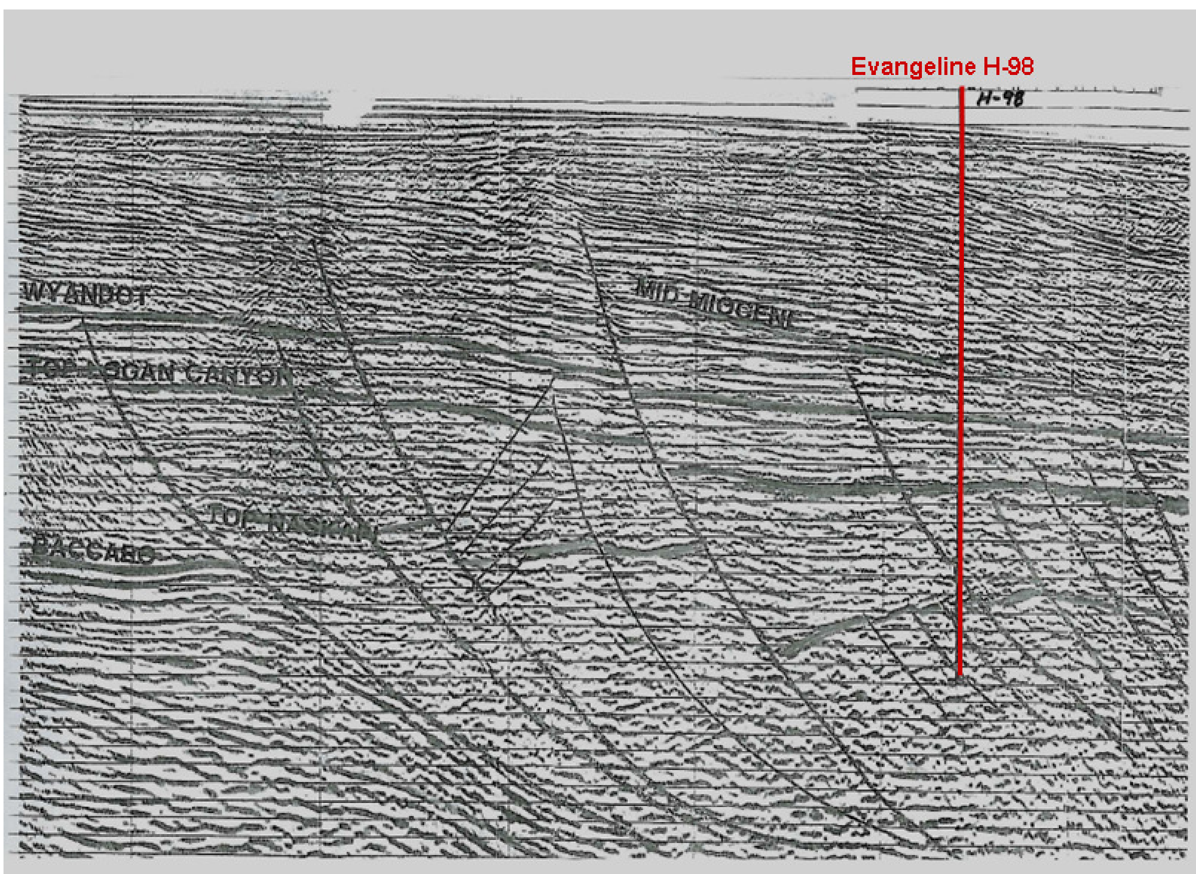


Figure 58. Pre-drill seismic used to define the Evangeline H-98 target (Husky).

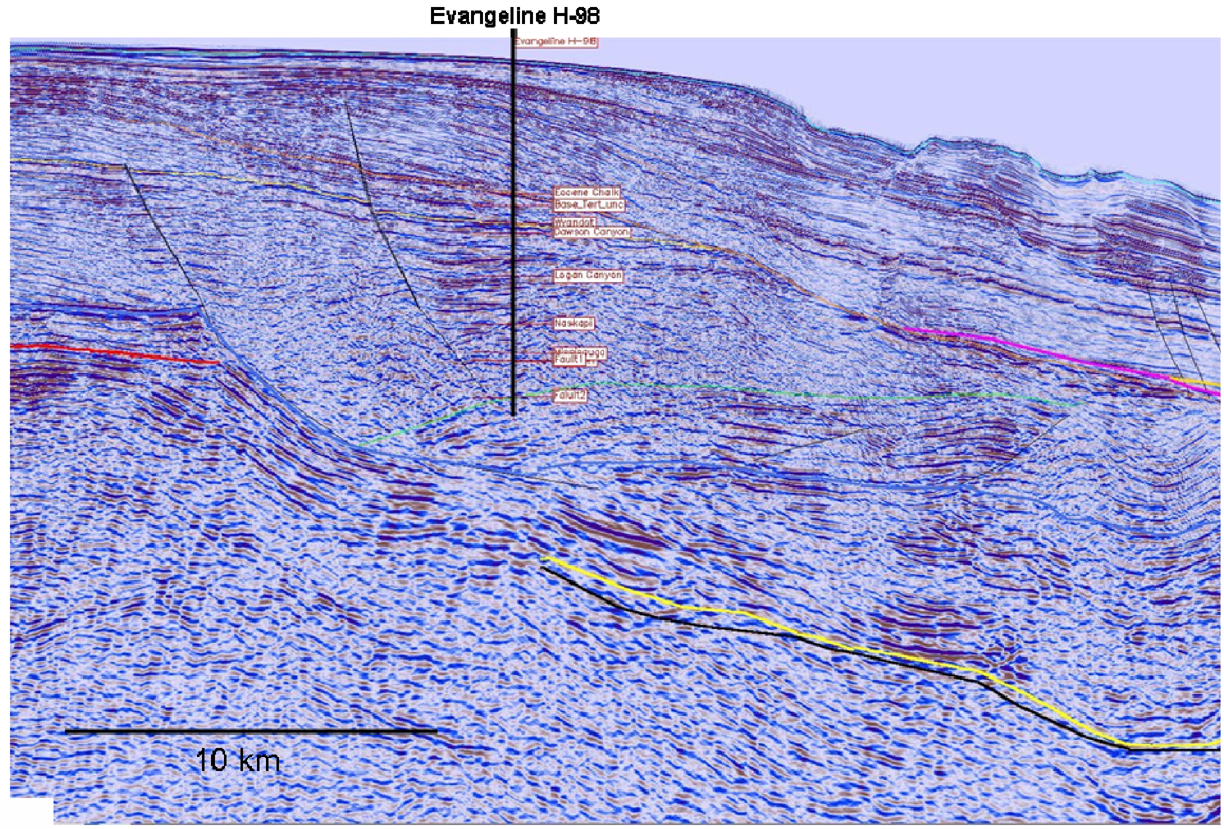


Figure 59. Modern regional 2-D seismic dip line through Evangeline H-98. Data courtesy of TGS-NOPEC.

5.2.2 Results

Drilling

The well was drilled to an FTD of 5044m MD (planned 5022m) bottoming in the Middle Albian (Enclosure B). The lower Logan Canyon and upper Missisauga equivalents (targeted pre-spud) were not penetrated due to the thickness of the upper Logan Canyon. The upper Logan Canyon equivalent in this well is over 2600m thick based on biostratigraphy; i.e. Late Cenomanian to Middle Albian, from 2390–5044 TD. Although there is considerable expanded thickness in this interval, very little sand was encountered in the well.

At 2773m MD in the Late Albian (Upper Logan Canyon Equivalent), two 2-3m thick fair to poor quality sands (<10% porosity) separated by 1m of shale were encountered (Figure 60). The "upper sand" generated a considerable gas show of 1230tgu/24u (total gas units / background gas units) and consists of very fine- to fine-grained, poor quality sandstone which appears gas charged. The "lower sand" has better porosity development. However, it has low resistivity and may be wet. Visible porosity was noted in this "lower sand" in both SWCs (side wall cores) and cuttings. Wireline pressure measurements (by RFTs) were attempted in these sands, however the tests resulted in lost seals which were probably caused by hole rugosity due to wash out.

While drilling at 4024m MD, the well took a kick which produced a gas show of 2800tgu/50u (the zone produced gas with minor condensate). The zone was found to be a 13m thick fractured limestone with relatively high pressure and low permeability and very little reservoir development (Figure 61). This zone correlates with the intersection of the wellbore and a major growth fault with the wellbore, and is interpreted as the top of overpressure. At 4333m MD, a 10m thick very fine- to medium-grained, heavily cemented, tight sandstone was encountered that produced no mud-gas response. Another fault zone is believed to have been intersected at 4649m MD as a significant gas show of

6500tgu/2800u occurred in a fractured calcareous shale. At 4801m MD another zone described as fractured calcareous shale (another fault?) produced a gas show of 1520tgu/100u background.

Consequently, while significant gas shows were detected, no reservoir quality sands were encountered. Due to the lack of sand, it appears the H-98 well is beyond the outer edge of the Sable paleodelta.

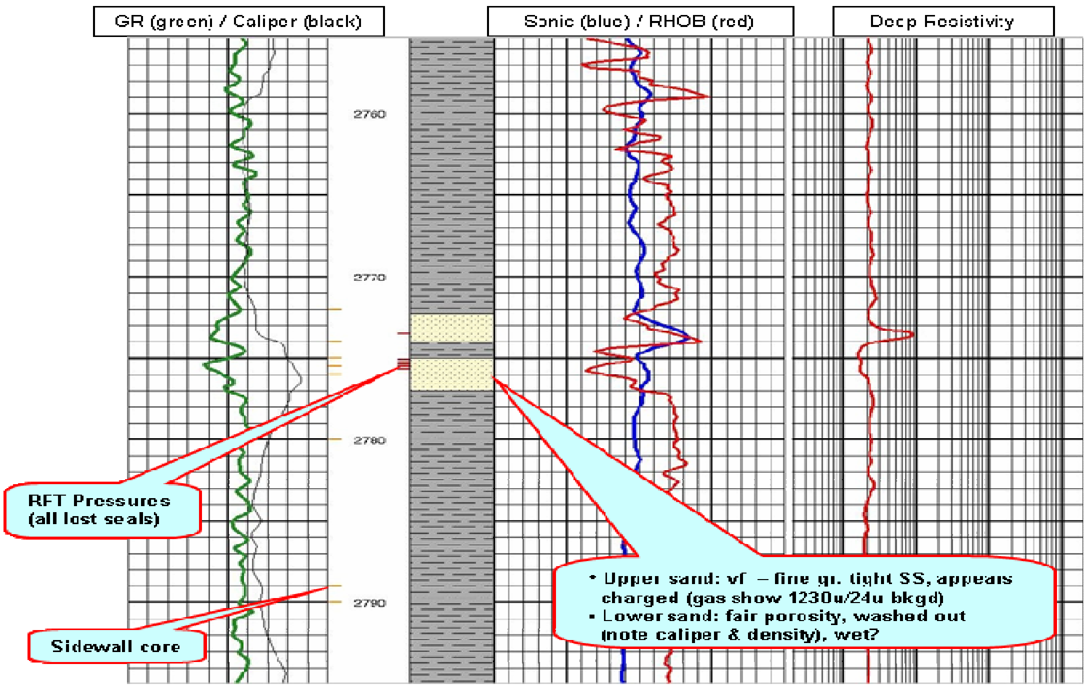


Figure 60. Evangeline H-98: Well logs from the Late Albian target (lower Logan Canyon).

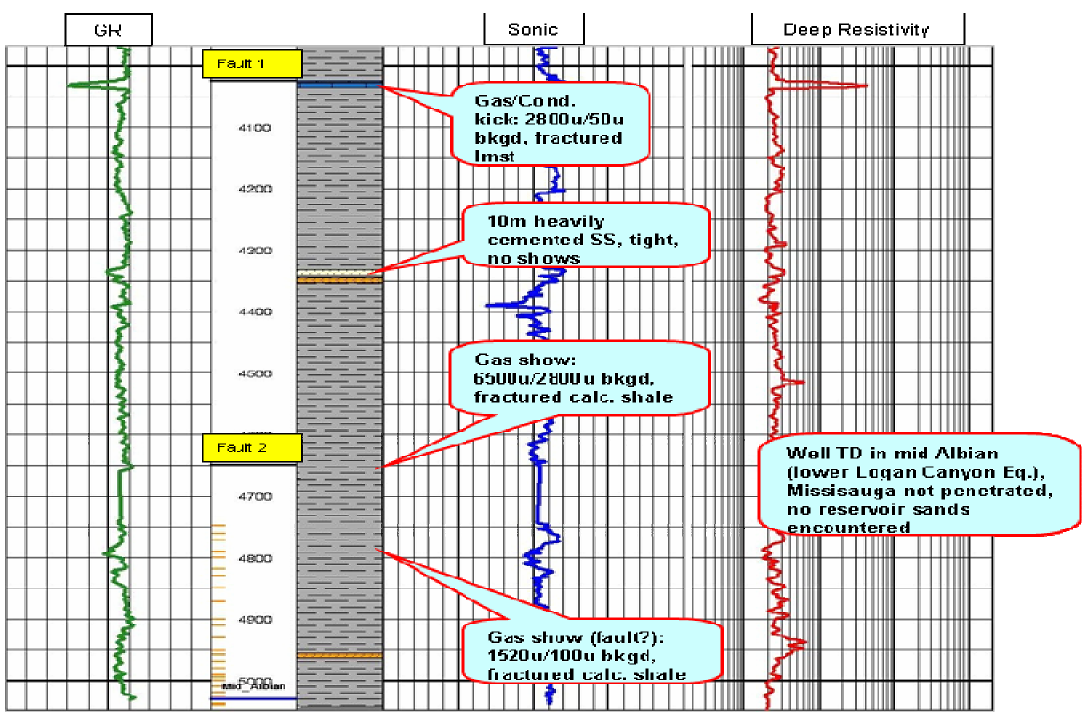


Figure 61. Evangeline H-98: Well logs from the Mid-Late Albian target (lower Logan Canyon).

Seismic Interpretation

The Evangeline structural interpretation has not changed with the addition of new seismic data. The structure is bounded by a large growth fault that was intersected by the wellbore, and contains a thick growth section of sediments with varying reflectivity (Figure 62). The upper Cretaceous section penetrated at Newburn would represent the distal portion of this expanded Cretaceous section at Evangeline. The yellow shading on the composite indicates the entire Cretaceous section. Based on the well results and well synthetic seismogram (Figure 63), the numerous seismic events are believed caused by calcareous shale reflections, multiples, broadside, interference, etc. and likely were the cause of the operator's overestimation of sand/shale intervals.

Biostratigraphy

Biostratigraphic and paleoenvironmental interpretation of the Evangeline H-98 stratigraphic succession was completed by the operator (Ford, 1987). Except for part of the Eocene and the Paleocene, no analysis was completed for most of the Banquereau Formation sediments. While biostratigraphic details are lacking, a significant unconformity of approximate Middle Miocene age is present (Enclosures D, E). The thin (~100 m) Tertiary section is mostly shale with minor chalks and marls. A minor unconformity appears to separate the Late Paleocene from the underlying Late Maastrichtian. This is followed by a virtually uninterrupted succession down to the Middle Albian.

The Cretaceous section is dominated by a thick section of Santonian to Maastrichtian Wyandot chalks below which shales and rare silts, marls and chalks, constitute the remainder of the interval (Turonian to Albian, possibly Aptian). The Albian is particularly thick (~2300 m – over half of the drilled section) though almost completely shale. Its thickness is speculated to be the result of sediment loading and deflation of underlying salt. Older fauna (Aptian to Hauterivian) are noted in the well. However, these are believed to be the result of reworking.

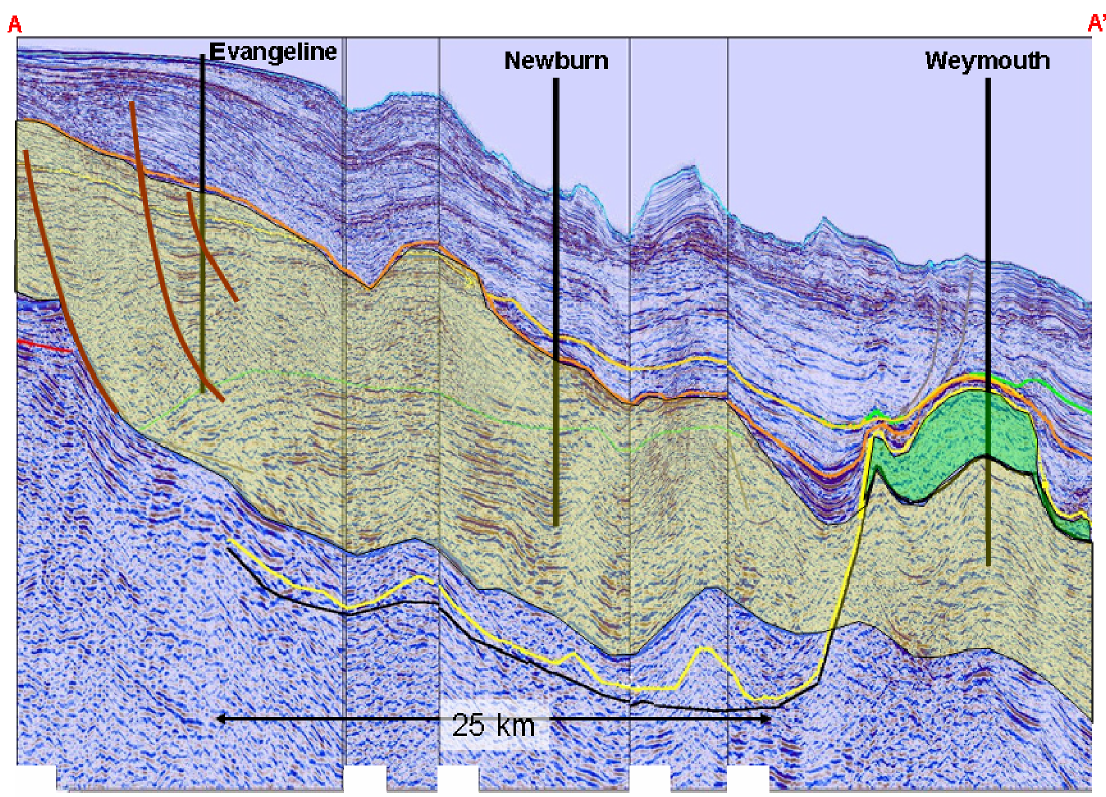


Figure 62. Composite 2-D seismic line through Evangeline H-98, Newburn H-23, and Weymouth A-45. Location shown in figure 57. Data courtesy of TGS-NOPEC.

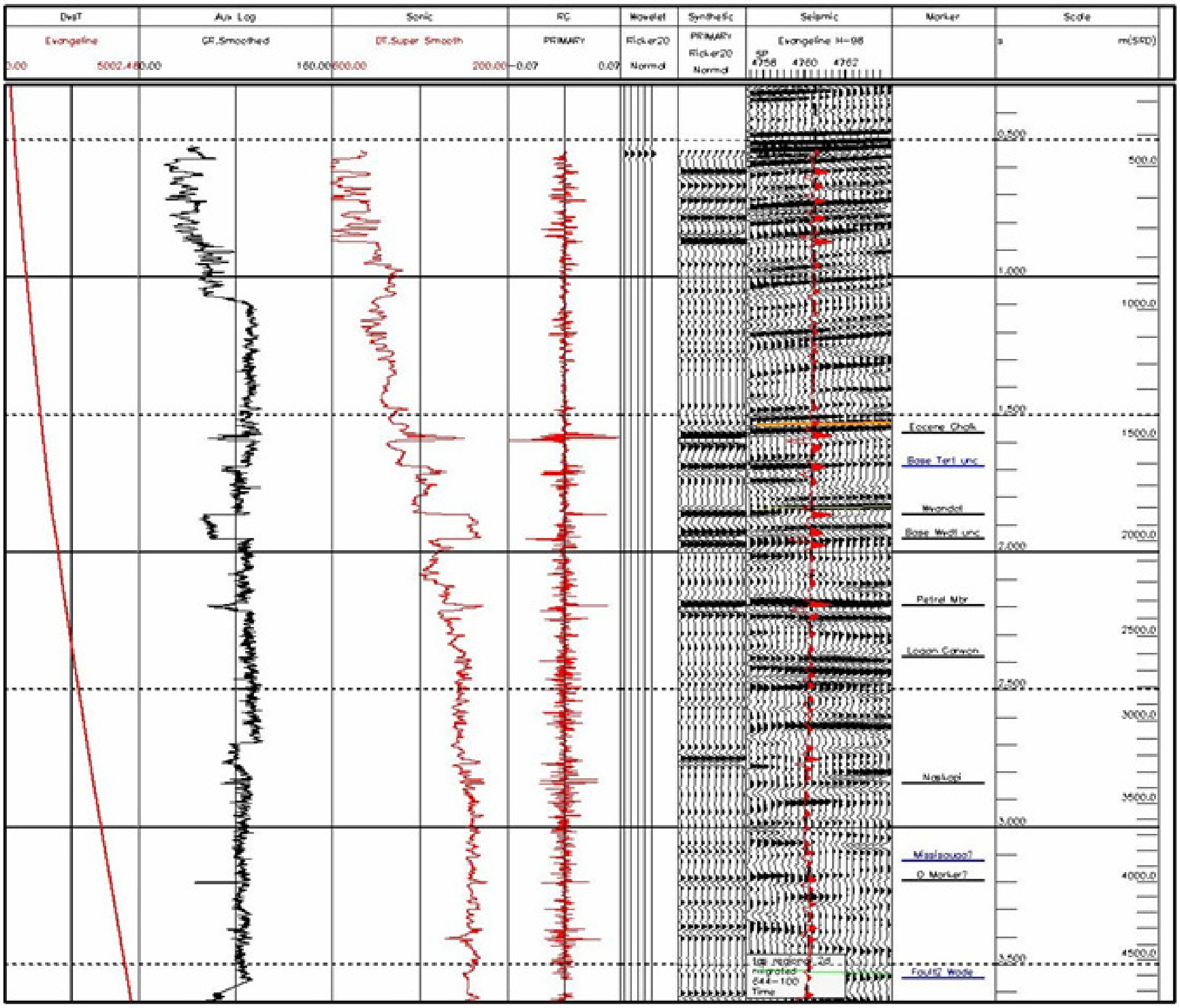


Figure 63. Evangeline H-98: Synthetic seismic.

Paleoenvironment

While thin, the sampled Tertiary section is believed to reflect deposition on the outer shelf (R. Fensome, GSC-A, 2005, pers. comm., and Enclosure B). The entire Late Cretaceous interval is interpreted to have been deposited in an outer shelf setting, with some possible indications of an upper slope environment in the upper Campanian and lower Cenomanian sections. The entire stratigraphic section is shale dominated with minor chalks and marls in the Eocene. The Albian sediments (Early Cretaceous) have a similar range, though older Aptian to Hauterivian strata were deposited in a well oxygenated open marine middle to outer shelf environment.

Geochemistry

An organic geochemical/ source rock facies analysis of 185 cuttings and sidewall cores samples from the well was conducted by GeoChem Laboratories for the operators (Geochem, 1985). Except for the lower part of the well, Type IIA-B to Type III kerogen types (mixed to woody-herbaceous) are dominant. The entire Tertiary succession is immature, and the Cretaceous is moderately mature throughout most of the lower Logan Canyon formation. Elevated maturation levels may reflect the combination of proximity to a deep salt mass and rapid burial due to salt evacuation.

Depth (m)	Formation	Age	Vitrinite Reflection (% Ro)	Kerogen Type	Maturity for oil generation
174	Sea Floor	Recent	n/a	n/a	n/a
1070 - 3160	Wyandot to Upper Logan Canyon	E. Eocene to E. Cret. (L. Albian)	~ 0.4 - 0.6	(II)-III	immature
3180 - 3600	Lower Logan Canyon (Cree Mbr.)	L. Cretaceous (L. Albian)	~ 0.75	(II)-III	moderately immature
3600 - 3800	Lower Logan Canyon (Cree Mbr.)	L. Cretaceous (L.-M. Albian)	~ 0.77	(II)-III	moderately mature
3800 - 5044	Lower Logan Canyon (Cree Mbr.)	L. Cretaceous (M. Cret.)	0.9 – 1.05	II > 4260 m I > 5024	mature

Table 3. Thermal maturation levels for the Evangeline H-98 well (Geochem, 1985). Note that the kerogen type in the lowest part of the well changes from mostly Type **III** woody-herbaceous to Type **II** amorphous and Type **I** algal. TOC values for all sediments ranged from 0.68-1.66 and averaged about 1%. Ro values are mean values for the interval.

Exploration Implications

The greatest geological risk for the Evangeline well was not the presence of a structural closure: it was the prediction of potential reservoirs within the structure. Though unsuccessful, the well results confirmed the southwest limit of the Sable paleodelta sand facies, basinward from which are potential deeper water sand depositional systems within a canyon/fan system. The lack of sand here suggests that in the Cretaceous it was a sediment bypass zone during sea level lowstands. Nevertheless, the Evangeline well remains a diagnostic test for the targeted play.

5.2.3 Well Operations

Pre- and post-spud well costs and pre-spud time estimates are not available for this well. The well was initially spudded with the Bow Drill **III** on March 27, 1984. After the 311mm hole section was completed, the well was suspended on June 16, 1984 and the rig moved to drill offshore Newfoundland. The well was re-entered on August 8, 1984 with the Bow Drill **II** and drilled to TD. The well required 178 days in total to drill and abandon including mob and demob. This includes 38.8 days of delays for items such as: BOP repairs, weather delays, rig repairs, stuck pipe/fishing, well control, casing and cementing etc.

5.2.4 Risk and Assessment

The well had no impact on the assessment because it lies on the shelf and is outside the slope area. Its inclusion in this report was to illustrate the evolution of deepwater play concepts and as a control well for the Newburn H-23 drilled two decades later.

5.3 Petro-Canada Shelburne G-29 (1985)

Using the newly commissioned Sedco 710 semisubmersible rig, the Shelburne well was spudded in 1154 metres of water on March 31, 1985 and rig released on September 16th, 1985 (Enclosure A).

5.3.1 Objectives and Concepts

There were two exploration targets at the Shelburne location: the primary objective a turbidite fan complex of early Tertiary/Late Cretaceous age and the secondary target a closure at the top of the Late Jurassic carbonate margin (Petro-Canada, 1985) (Figure 64).

The seismic detection of submarine fans during this period was based on North Sea analogues which had proven highly successful in that basin (see Section 3.3.1). The exploration concepts were based on 1984 2D seismic surveys (Figure 65). Based on period seismic, a large lobate fan-shaped anomaly was mapped with dimensions estimated to be 30km long by 15km wide (Figure 66). The anomaly was interpreted as a submarine fan stratigraphic trap with minimal structural closure. The fan sequence appeared seismically to pinch out between overlying and underlying Tertiary and Cretaceous age shale-dominated successions that would act as trap seals.

The primary target fan complex was tested near its landward or up-dip end so that the well bore could also reach and evaluate the deeper carbonate structure. The secondary target was a southwest plunging Jurassic carbonate promontory interpreted, by the operator, to be salt-cored and draped with Scatarie member oolitic shelfal limestones of Middle Jurassic age and older.

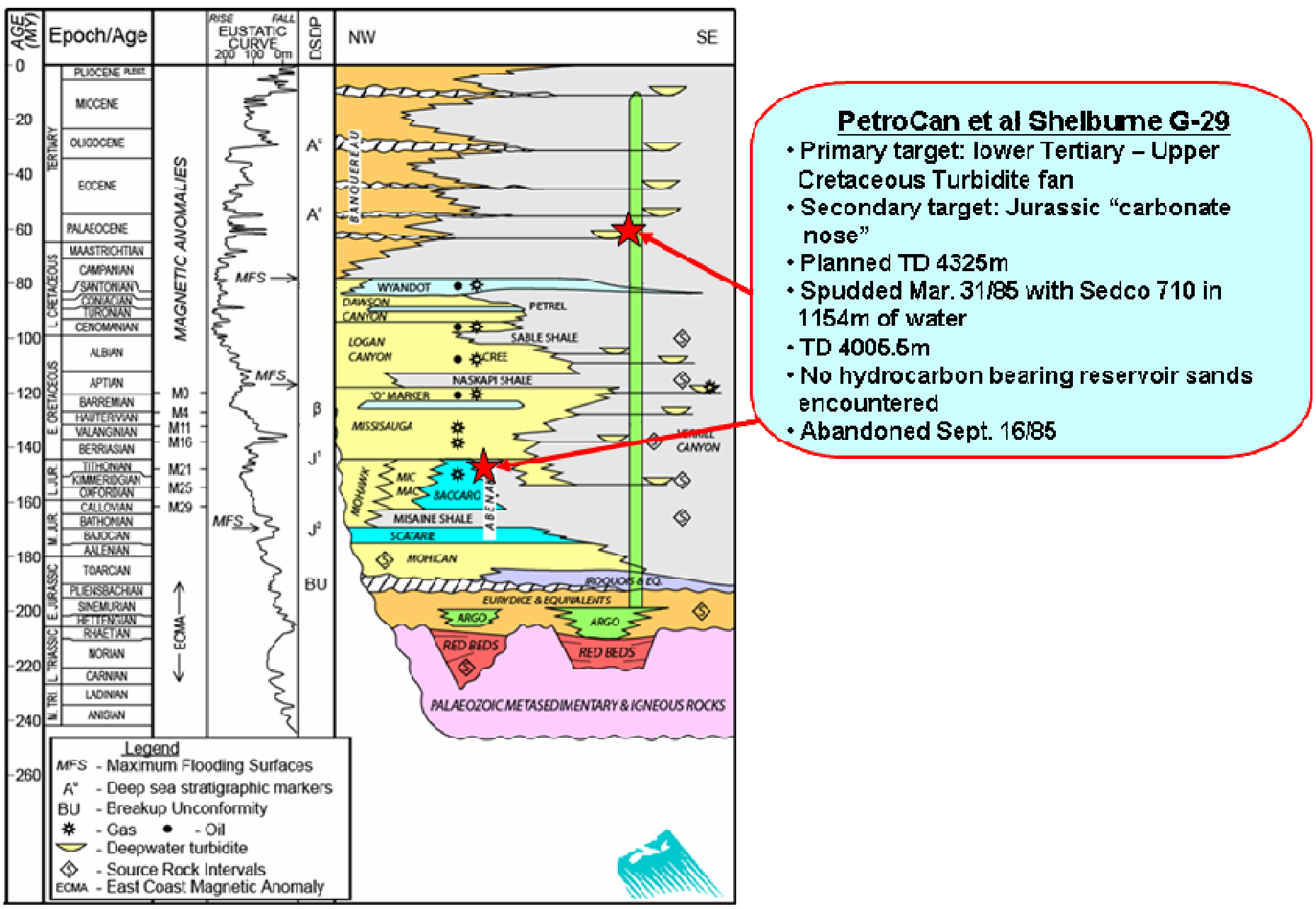


Figure 64. Stratigraphic chart showing target intervals for Shelburne G-29.

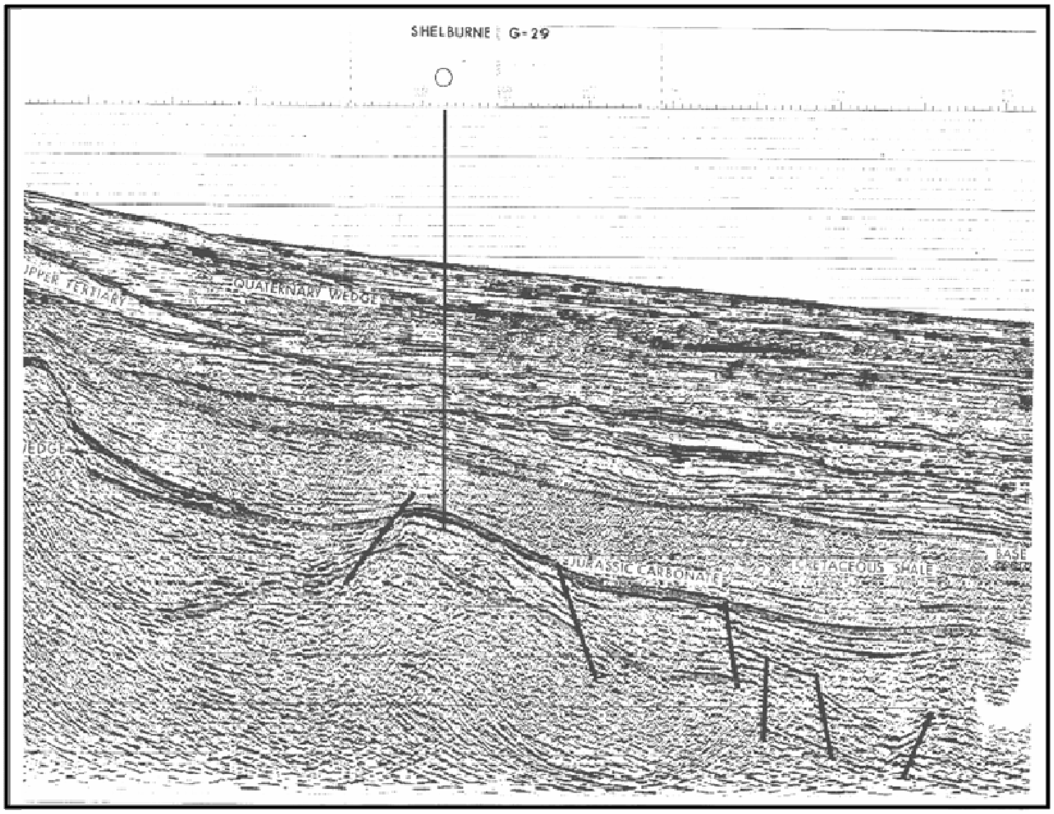


Figure 65. Pre-drill seismic used to define the Shelburne G-29 target (Petro-Canada).

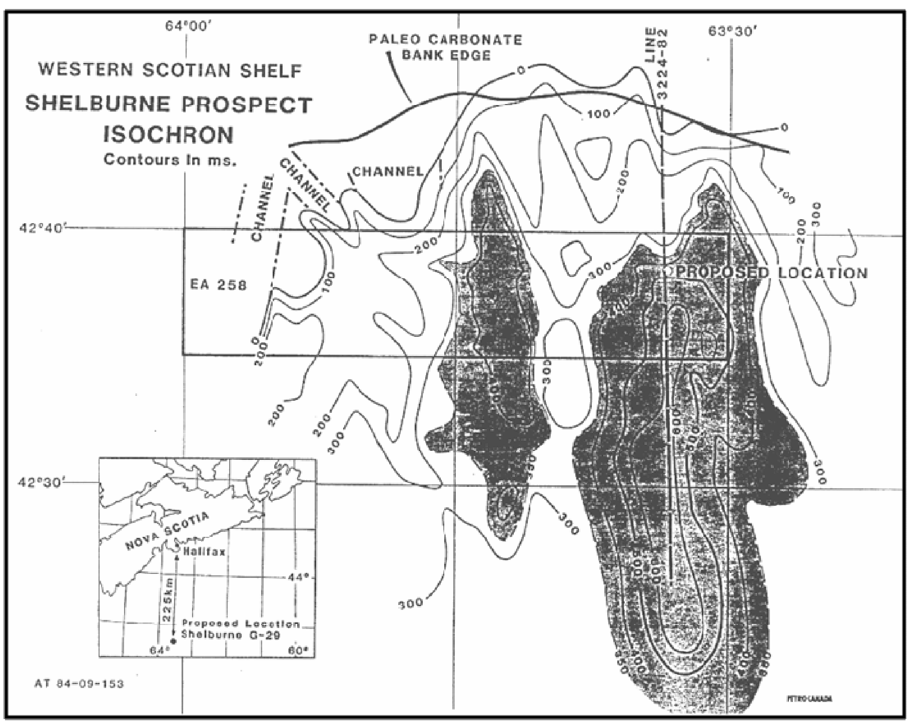


Figure 66. Shelburne location isochron map (Petro-Canada).

5.3.2 Results

Drilling

The Shelburne well was drilled to an FTD of 4005.5m ending in the top of the Jurassic versus the planned TD of 4325m (Enclosure B). The primary target early Tertiary/Late Cretaceous fan was not present and only the top of the secondary Jurassic target was penetrated. The drill string became stuck during coring the Jurassic and was only partially recovered. As a result, log data was only acquired down to the top of the fish at 3820m near the base of the Late Cretaceous Logan Canyon formation.

A 30m thick, fine- to coarse-grained, poorly sorted, wet sandstone with generally poor porosity was found in the Pliocene between 1615–1640m (Figure 67). This sand also contained pebble-sized quartz, chert and igneous clasts and may be a glacial channel lag deposits. A sidewall core recovered from the base of this sand had estimated porosity of up to 15%. Several generally thin, very fine- to fine-grained silty sandstones were encountered in the Middle Tertiary (Miocene to Eocene). However, these sands were tight and are not hydrocarbon charged (Figure 68). The primary target interval consisted mostly of shale with some limestone and marl. No reservoir sands were present and after reviewing the recent seismic data the “fan” appears to be an erosional remnant (Figure 69). This interpretation is consistent with the lithology encountered in the well. Below the target interval a 10m zone of interbedded very fine- to fine-grained sandstone and shale was encountered at a depth of 3633m. However, this interval has poor porosities (3–8%) and did not have any mud-gas shows during drilling.

The Jurassic carbonate was penetrated six metres prior to the decision to cut a conventional core. After coring for 14m the core barrel jammed and the drill pipe became stuck during the trip out of the hole. The drill cuttings were described as skeletal and oolitic wackestones to packstones deposited on a reef margin foreslope. Reservoir quality was poor with porosity estimated as 3–5%. No shows were observed (Figure 70).

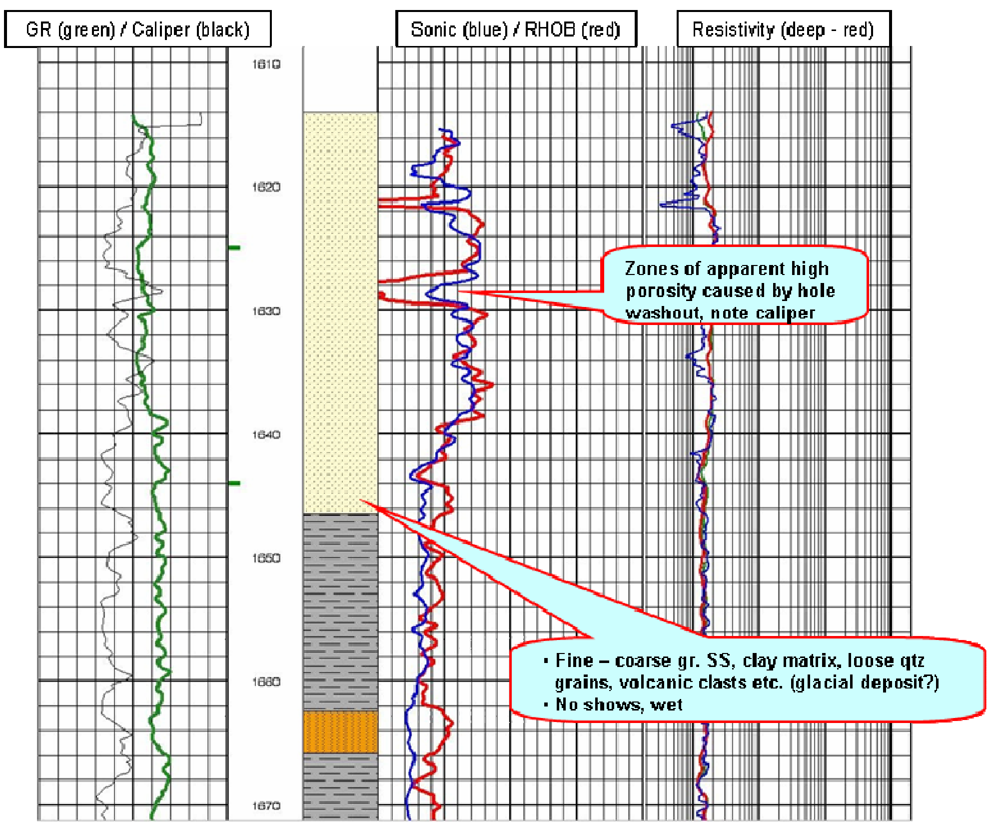


Figure 67. Shelburne G-29: Well logs from the Pliocene sand.

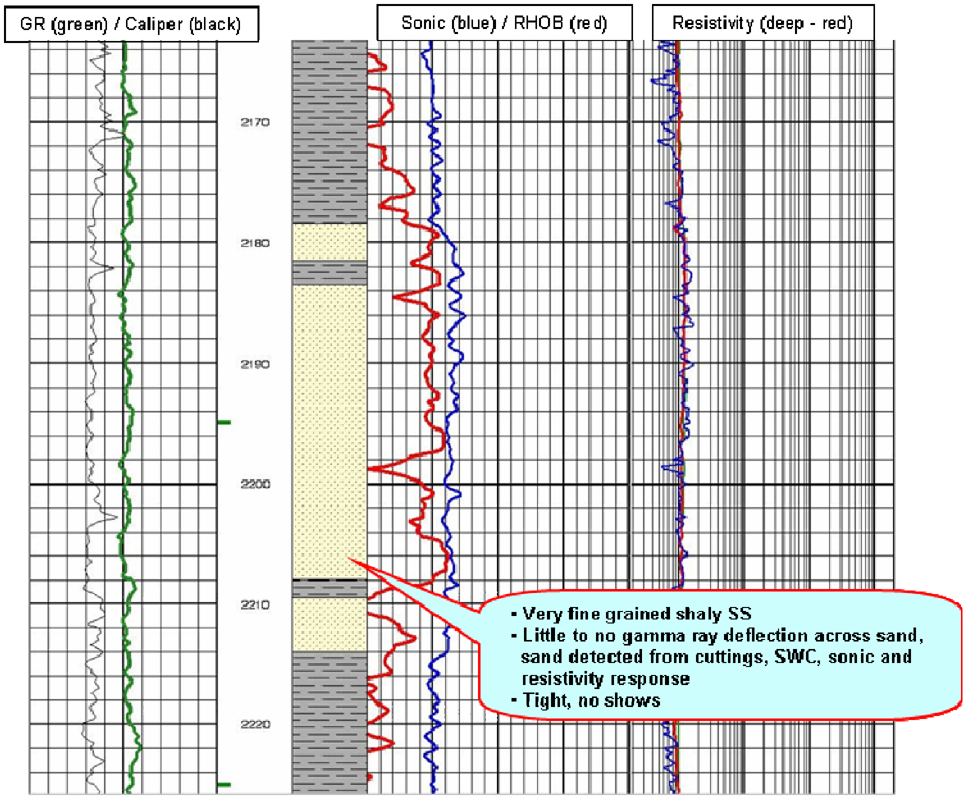


Figure 68. Shelburne G-29: Well logs from the Miocene sand.

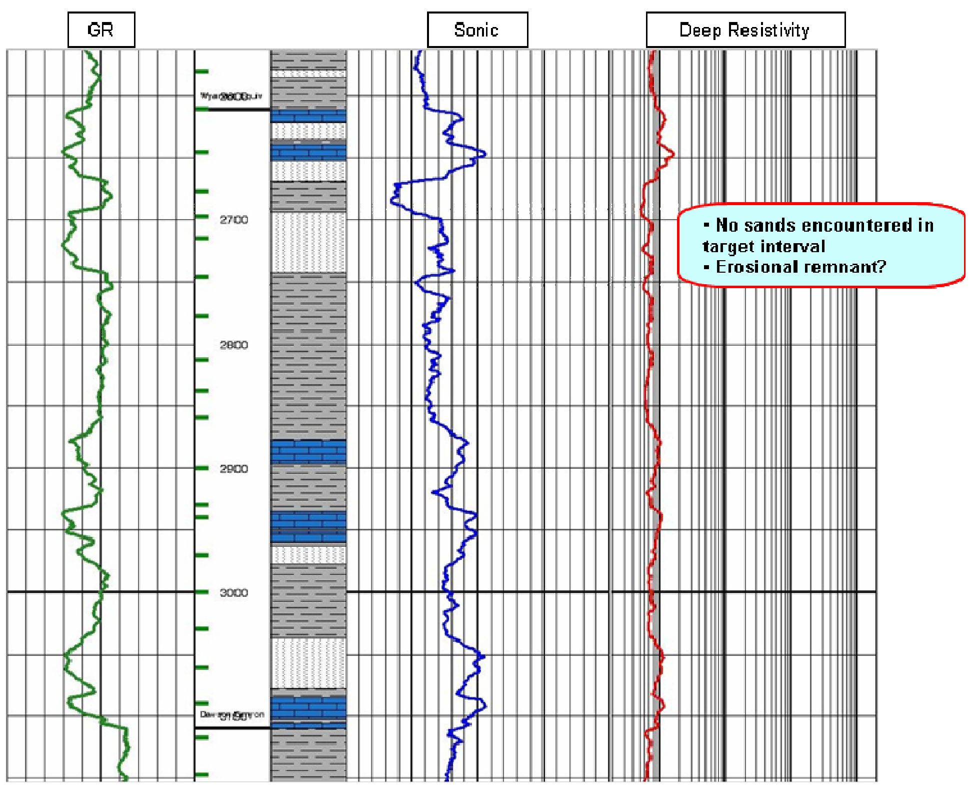


Figure 69. Shelburne G-29: Well logs from the target "Fan" interval.

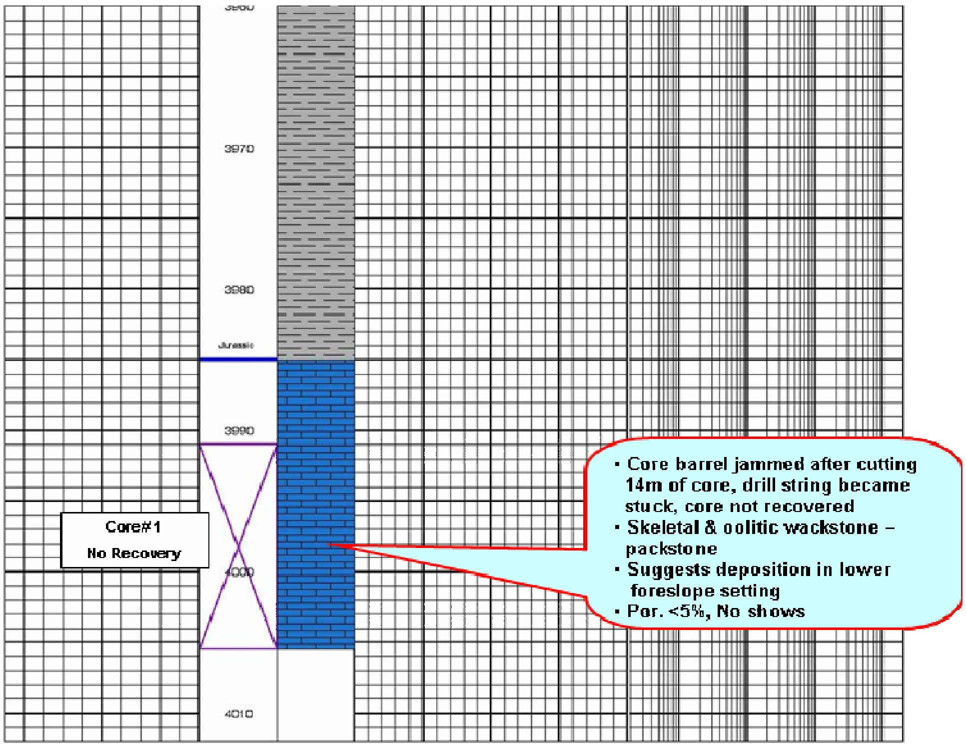


Figure 70. Shelburne G-29: Geological strip log over the Jurassic target.

Seismic Interpretation

The Base Tertiary time map was created from the TGS-NOPEC 2D regional survey acquired during 1999-2000. It illustrates a "wavy" contour pattern that is similar to the same interval at Shubenacadie that is likely caused by channels cutting downward across the slope (Figure 71). This data supports the new interpretation that the previously interpreted Shelburne fan is a subcrop remnant below the Base Tertiary (Paleocene to Eocene) unconformity.

The Shelburne well's secondary target is defined by a Late Jurassic high on a topographic nose projecting out from the carbonate bank edge and is mirrored at the Middle Cretaceous level (Figure 72). Because the seismic line is oblique to the dip, both the west and east sides of the Base Tertiary channel can be observed. The seismic strike line through the well reveals truncations of the parallel reflections below the Base Tertiary unconformity within the targeted feature indicating that the structure is an erosional remnant (Figure 73). There is a generally good correlation between the synthetic seismic and the well identifying the major seismic events (Figure 74). Shelburne is thus an excellent illustrative example of one of the pitfalls of interpreting erosional remnants as fans as noted by Mitchum (1984).

Biostratigraphy

Biostratigraphic information for this well is from Thomas (2000) and Fensome (2003). Within the Tertiary succession (Banquereau formation), the Mid Miocene unconformity cuts into the Mid Eocene with an approximate 27 Ma time gap due to mass wasting (Enclosure D). Whether non-deposition and/or condensed intervals existed within the eroded interval is unknown. The erosional remnant, originally interpreted as a submarine fan complex contains a continuous succession of Middle Eocene to Early Aptian calcareous mudstones and some marls and outer shelf pelagic carbonate mudstones. Virtually the entire Early Cretaceous (lower Logan Canyon and Missisauga formations) is absent – an approximate 34 my time gap. The cause of this latest Aptian (?) event is unknown. However, it could have been the result of non-deposition, thin condensed sections, submarine erosion or any combination of these processes. The well bottomed in latest Jurassic Abenaki equivalent carbonates.

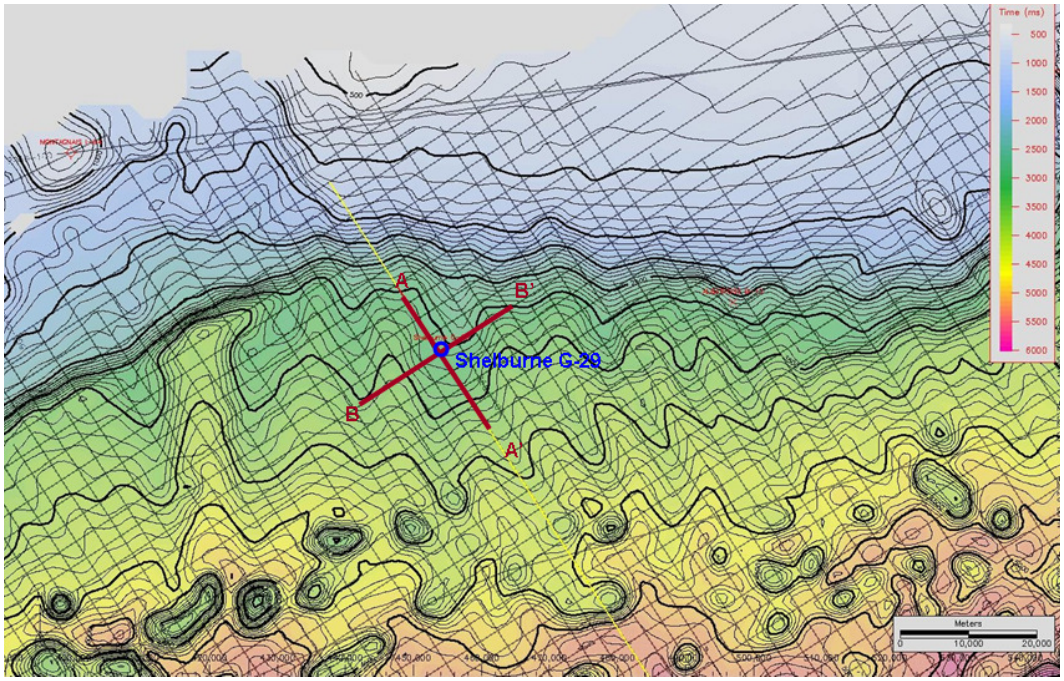


Figure 71. Regional 2-D seismic near Shelburne G-29. Line A-A' is shown in Fig. 72; B-B' is shown in Fig. 73.

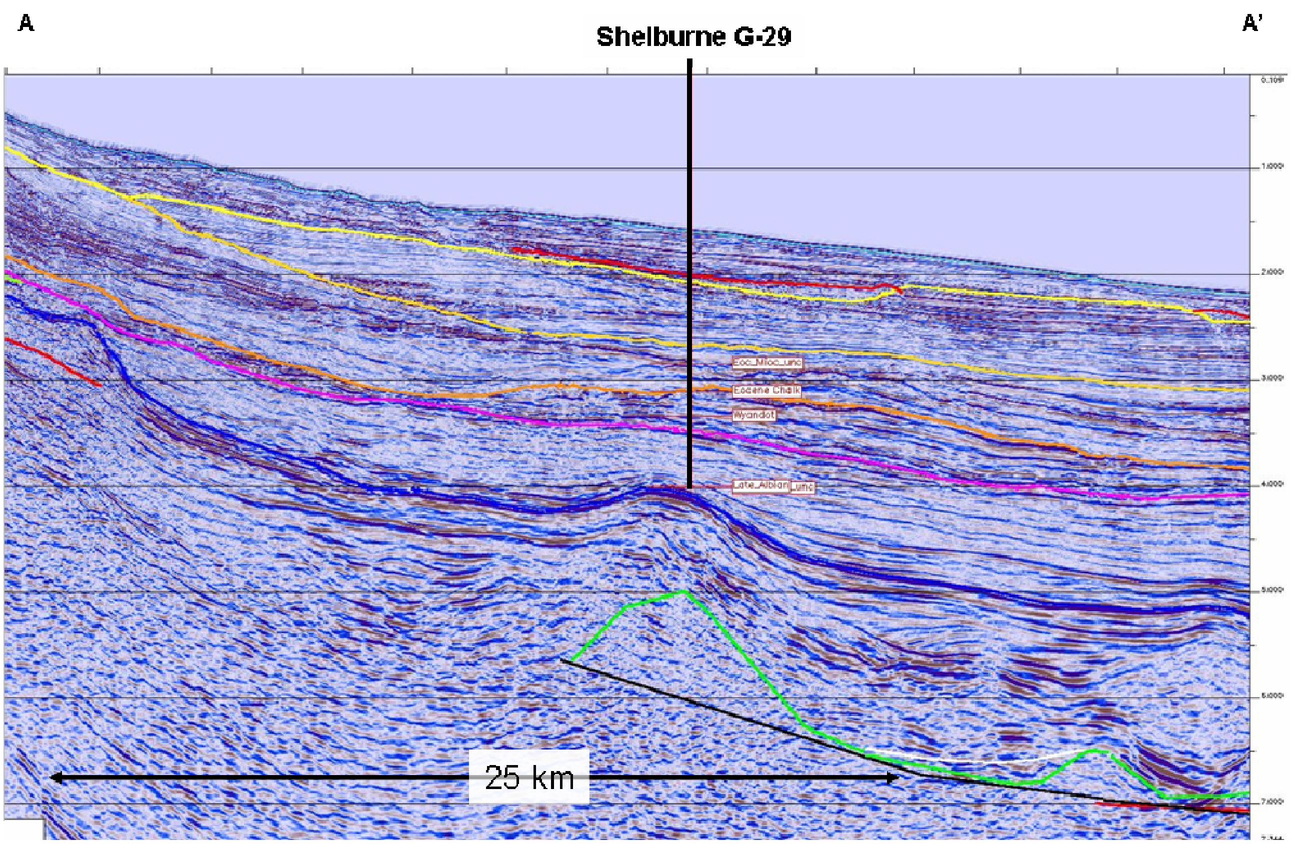


Figure 72. Modern regional 2-D seismic dip line through Shelburne G-29. Data courtesy of TGS-NOPEC.

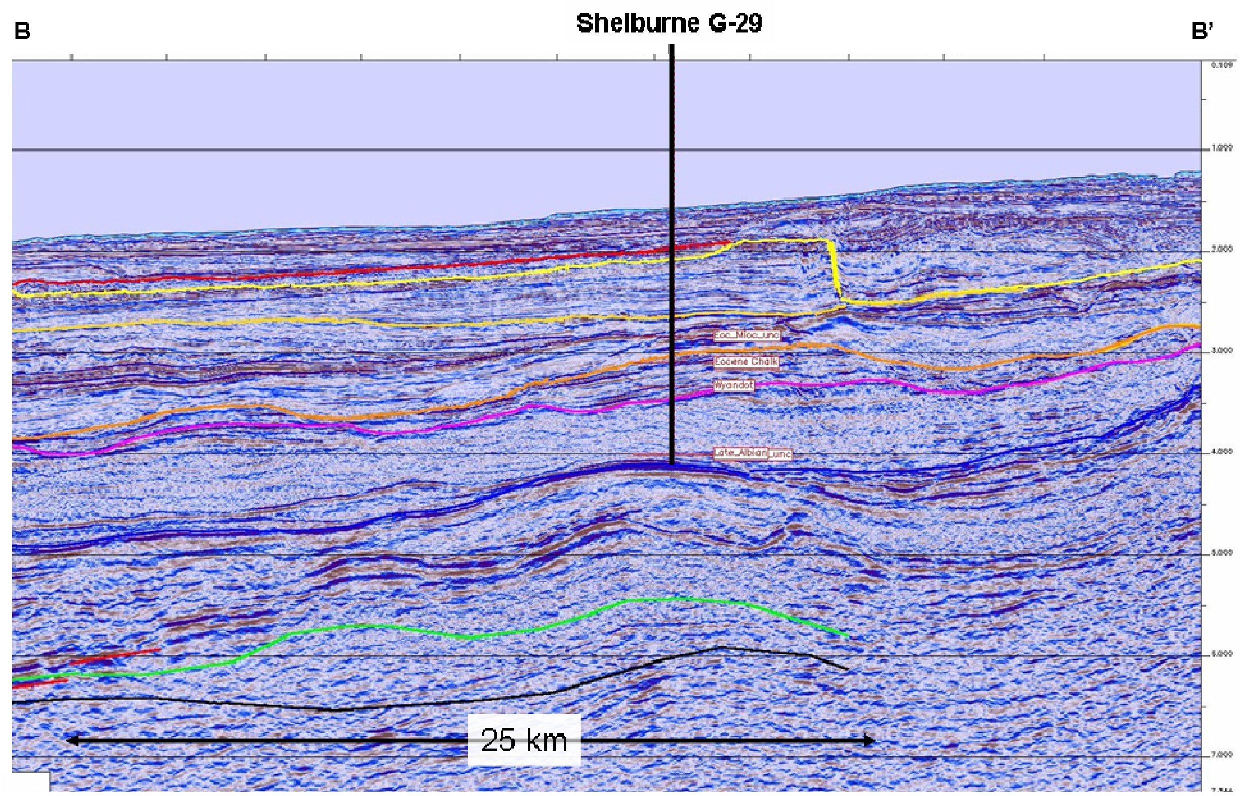


Figure 73. Modern regional 2-D seismic strike line through Shelburne G-29. Data courtesy of TGS-NOPEC.

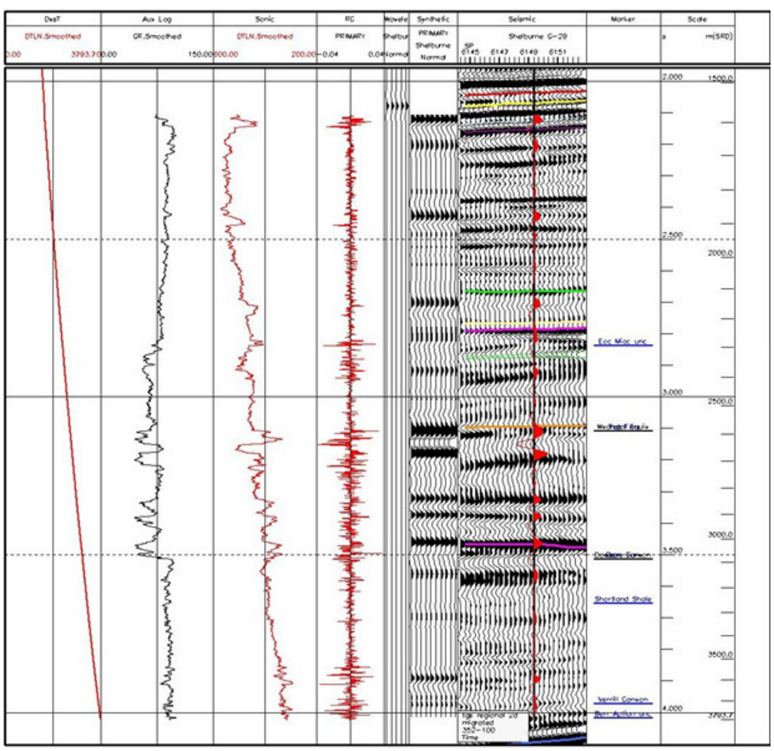


Figure 74. Shelburne G-29: Synthetic seismic.

Paleoenvironment

A paleoenvironmental analyses for the was completed by the Geological Survey of Canada (Thomas, 2003) that interpreted a middle slope environment for the Maastrichtian to Middle Miocene section, and a slight shallowing to the upper slope in the Middle-Late Miocene and outer shelf in the Pliocene. Micropaleontology analysis for the Cretaceous was not undertaken and therefore no paleobathymetric interpretations were made for this succession.

Geochemistry

Vitrinite reflectance (Ro) analysis of dispersed organic material from 14 cuttings samples was completed for this well by the Geological Survey of Canada (Avery, 1999b). The organic matter type was not noted in this report. Presumably it is the typical Type IIA-B to Type III kerogen types (mixed to woody-herbaceous) common to the ubiquitous Verrill Canyon formation and its equivalents. The data indicate that the Tertiary and latest Cretaceous strata are immature. The remaining Late Cretaceous section is marginally mature, within the oil-generating window, and capable of generating liquid hydrocarbons. The basal latest Jurassic sediments have the same maturity level as the overlying Cretaceous.

Depth (m)	Formation	Age	Vitrinite Reflection (% Ro)	Maturity for oil generation
1154	Sea Floor	Recent	(0.23)	n/a
2970	Wyandot	Campanian (L. Cret.)	0.4	immature approaching maturity
3720	Logan Cyn. Eq.	Albian (L. Cret.)	0.5	marginally mature
3985	Abenaki	Tithonian (L. Jur.)	0.54	marginally mature
4055 (TD)	Abenaki	as above	as above	marginally mature

Table 4. Thermal maturation levels for the Shelburne G-29 well (from Avery, 1999b). Note that the value for the seafloor in brackets was calculated from the derived / extrapolated Ro slope of 0.128 log Ro/km.

Exploration Implications

The main implication from the Shelburne well results is that like Shubenacadie H-100, the Tertiary fan play was not tested. An erosional remnant containing inter-bedded shales, marls and limestones representing the regional background succession of the Tertiary age shelf margin progradational succession was again mistaken for a submarine fan. One of the operator’s probable assumptions was the presence of a major regional shelf - margin - slope paleodrainage system converging at the Shelburne locality. However, the identification of such a system was much less precise and riskier 20 years ago. In fact, on the shelf margin and slope, this play concept remains an elusive goal even with modern 3D seismic.

Therefore, the Tertiary succession at Shelburne appears quite similar to the Shubenacadie area. It is relatively immature for the generation of hydrocarbons and therefore potential plays must invoke migration from deeper, more mature source rocks.

5.3.3 Well Operations

Actual well costs were not reported for this well. It was estimated that it would take 64 days to drill the well. In spite of operational delays the well was drilled in 55 days because drilling progressed faster than expected and TD was called 300m higher than originally planned (Figure 75). A total of 13.5 days of non-productive time was experienced with these delays mainly related to coring/tripping, logging, hole stability issues: i.e. swelling shales and rig repair.

5.3.4 Risk and Assessment

Shelburne lies in the Western Upper Slope play area of the Board's 2002 assessment where the dominant play type is pre-Tertiary anticlinal features and tilted fault blocks. The Tertiary slope fans were a secondary play and not assessed, thus the results of this well have little to no impact on the assessment.

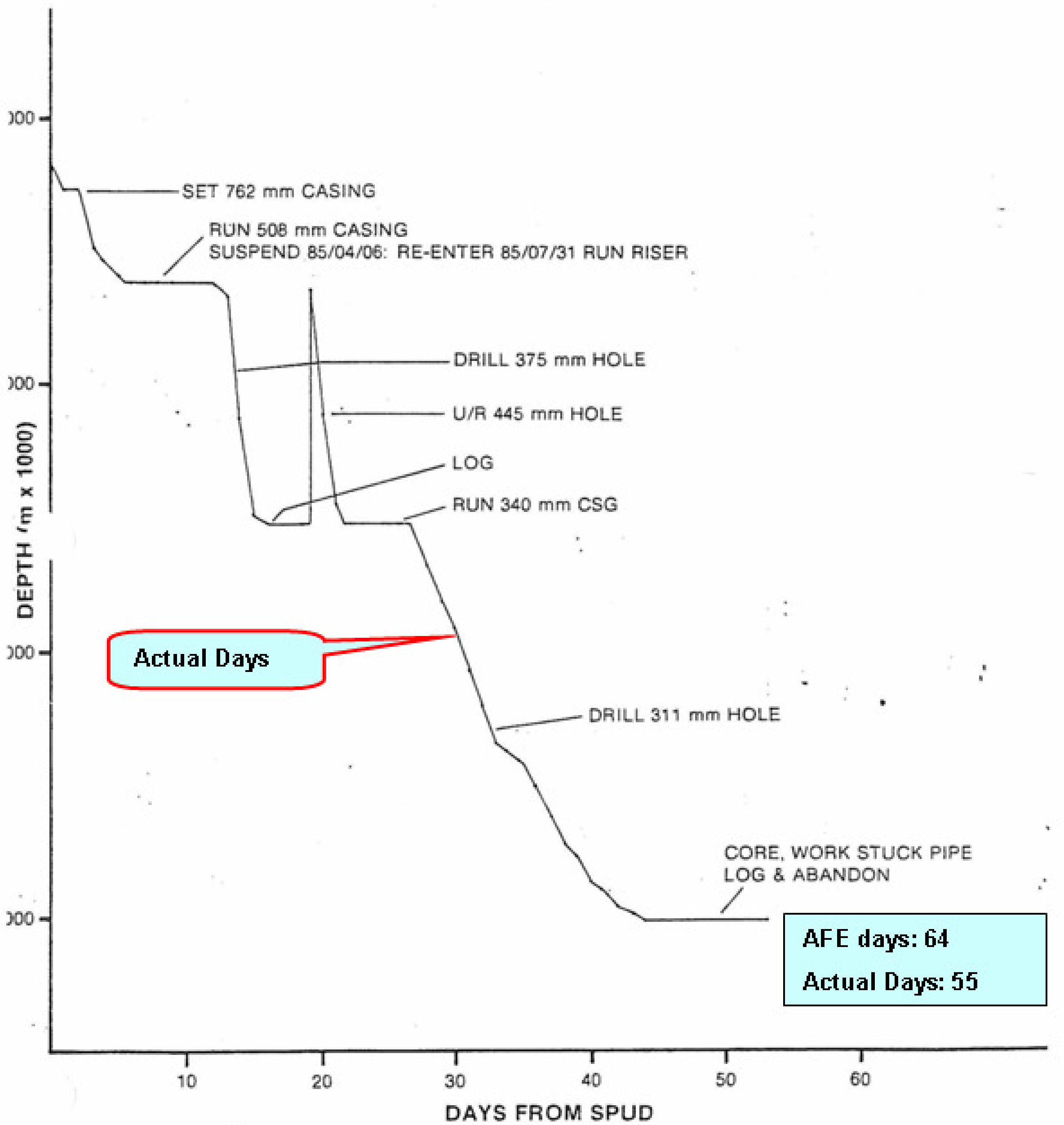


Figure 75. Shelburne G-29: Time vs. depth curve (actual).

5.4 Shell Tantallon M-41 (1986)

Shell's second foray into the deepwater offshore Nova Scotia was at the Tantallon prospect. It was located in 1540m of water and was spudded on February 15, 1986 by the Sedco 709 semi-submersible with the rig released on April 18th, 1986 after completion (Enclosure A).

5.4.1 Objectives and Concepts

This well is located south of the Banquereau Bank shelf wells on the east side of the Sable paleodelta. The structural anomaly is well defined but without the degree of faulting observed at Evangeline. The objectives for the Tantallon well were Cretaceous age (Missisauga and lower Logan Canyon formation equivalents) turbidite sands trapped within a large low-relief rollover anticline on the downside of a down-to-basin listric fault (Shell, 1986) (Figures 76 & 77). The location was based on existing 2D seismic from the early- to mid-1980's and was probably based only on structural mapping with a crestal well location defined.

This well is located south of the Banquereau Bank shelf wells on the east side of the Sable paleodelta. The structural anomaly was well defined but without the degree of faulting observed at the Evangeline location. The well targets were slope turbidites, not shelfal deltaic sands.

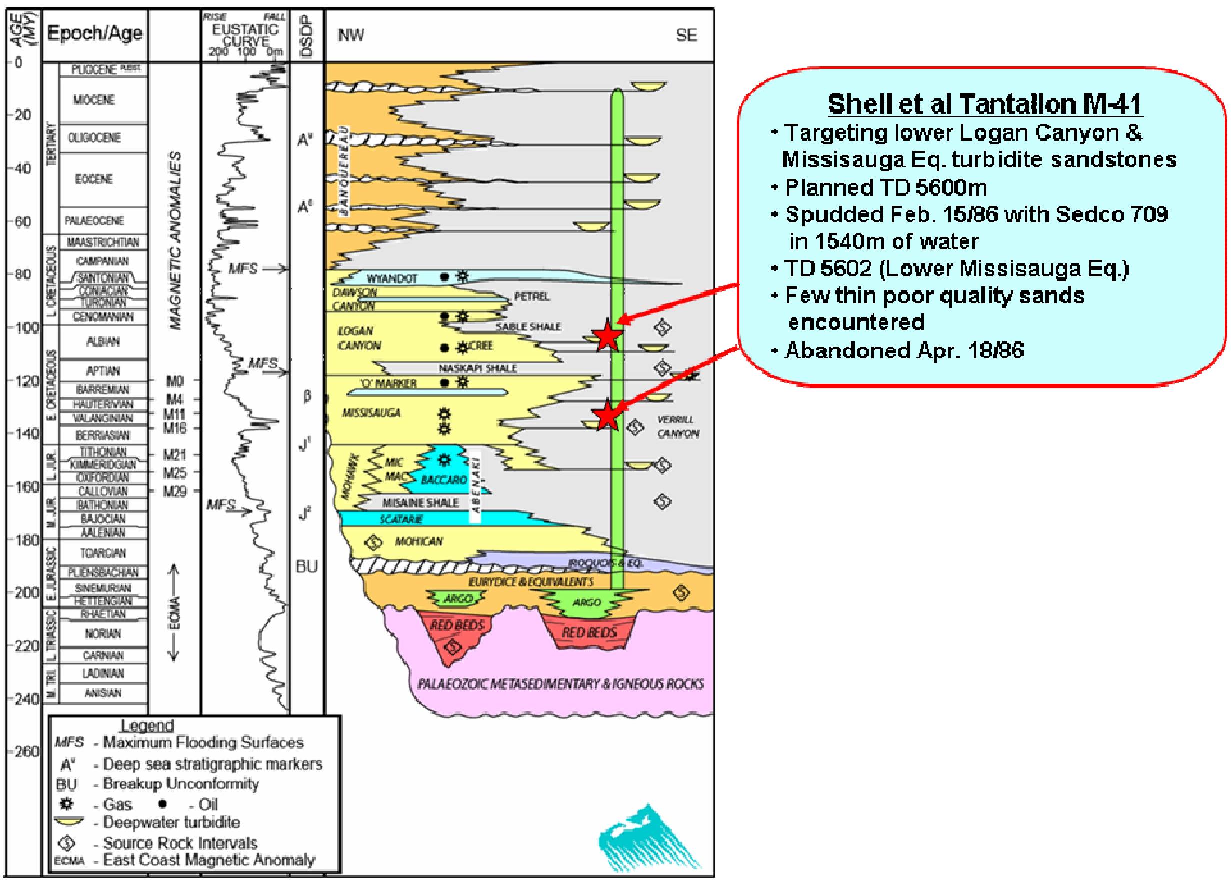


Figure 76. Stratigraphic chart showing target intervals for Tantallon M-41.

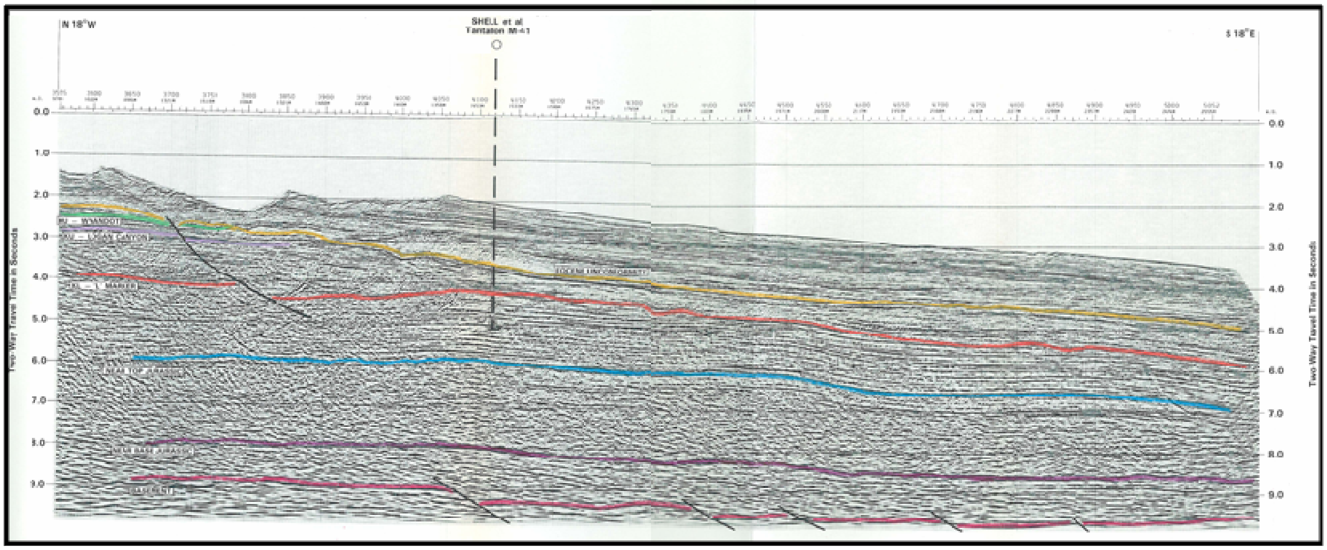


Figure 77. Pre-drill seismic used to define the Tantallon M-41 target (Shell).

5.4.2 Results

Drilling

Tantallon M-41 was drilled to a TD of 5602m (planned TD 5600m) in the lower Missisauga equivalent section (late Valanginian) (Enclosure B). The lower Logan Canyon and Missisauga target intervals consisted primarily of shale with a few generally thin poor quality sandstones and siltstones. No gas kicks or abnormal pressures were encountered in the well. A few zones of interest were noted and are described below.

Two Miocene age sands were encountered in the well. The upper sand at 2416m is approximately 10m thick and is a poorly consolidated fine- to coarse-grained with sub-angular, moderately sorted sand grains (Figure 78). Since the sand is poorly consolidated it washed out during drilling causing porosity readings across the zone to be unreliable. Although the porosity data is questionable, the resistivity of the sand is very low (0.7 ohms) and no mud-gas shows were detected during drilling indicating the zone is likely wet. The other Miocene sand was penetrated at 2484m and is about 12m thick. It is described as a poorly consolidated fine- to medium-grained, sub-angular moderately sorted sandstone. This zone is also washed out affecting the porosity logs; however the low resistivity readings suggest the sand is porous and wet.

At 5207m, a 14m thick very fine- to fine-grained, sub-angular, well sorted sandstone was encountered in the Late Hauterivian (upper Missisauga equivalent). With the exception of two thin (0.5m) intervals with 11% porosity, i.e., a total of 1m with porosity >10%, the remaining sand was tight with porosity <10% (Figure 79). With calculated water saturations (Sw) of approximately 60%, it is possible that the sand has some gas charge. However, the low porosities on the sand (majority <10%) makes the Sw calculation more interpretive. The gamma ray log displays a fining upward profile and this along with the interpreted paleowater depth from biostratigraphic analysis suggests the zone may be an outer shelf channel sand. Over 300 percussion sidewall cores and three conventional cores (below) were cut in the Tantallon M-41 well.

- Core #1: 3600.0 – 3627.0m, Rec. 23.5m
- Core #2: 4689.0 – 4717.0m, Rec. 28.0m
- Core #3: 5294.0 – 5313.0m, Rec. 16.3m

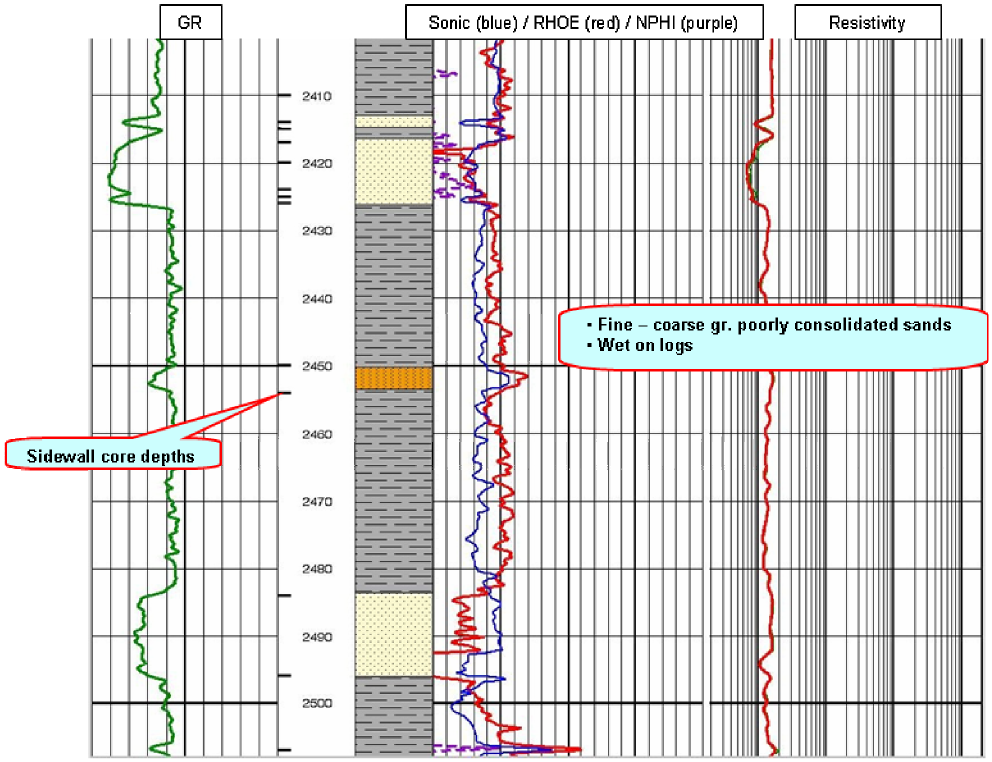


Figure 78. Tantallon M-41: Well logs from the Miocene Sand interval.

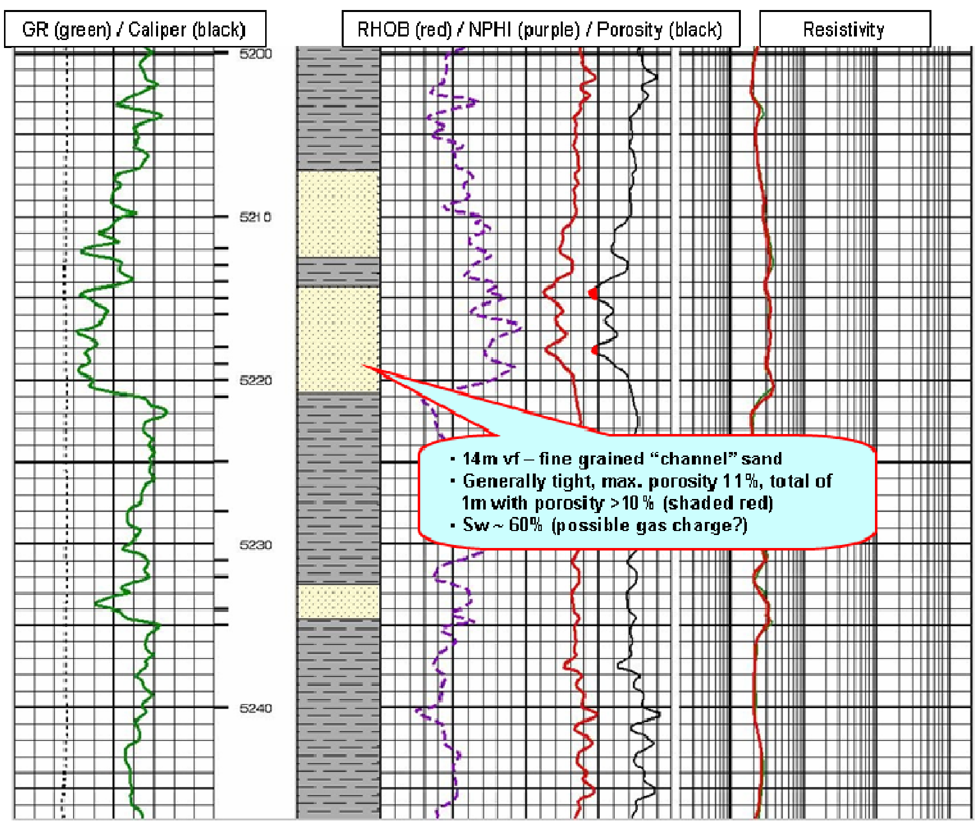


Figure 79. Tantallon M-41: Well logs from Late Hauterivian sands (Missisauga equivalent).

Unfortunately, the cores were cut in shale dominated intervals, therefore, only minor sandstone was recovered (Enclosure B). A portion of each core was photographed and is described below:

Core #1 was cut in Albian age sediments and consists primarily of grey calcareous partially bioturbated shale (Figure 80). Thin stringers of calcareous silt and very fine-grained sandstone lamina are occasionally present. Paleowater depths from biostratigraphic analysis indicate the water depths ranged from 100–1000m which suggests the sediments may be prodelta shales or upper slope deposits (Robertson Research, 2000b).

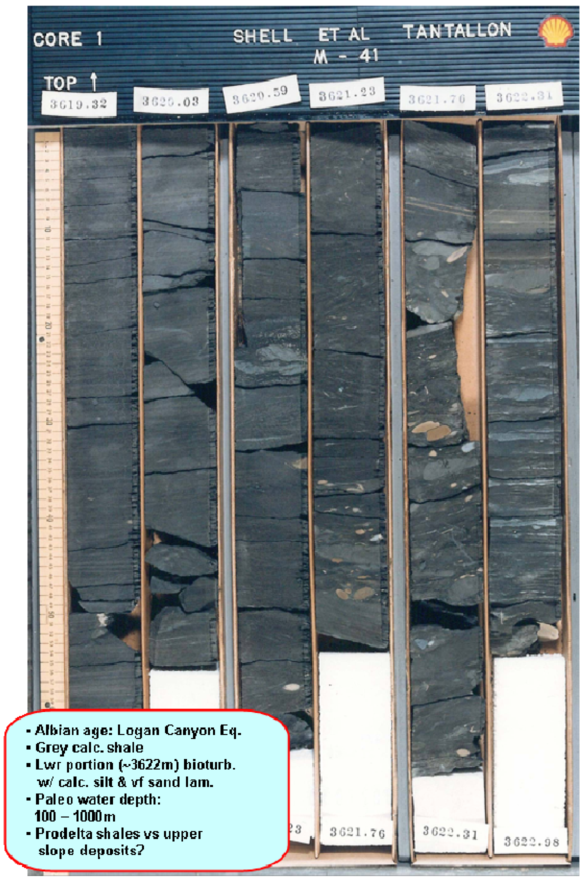


Figure 80. Tantallon M-41: Portion of Core #1 (3600.0 – 3627.0 m, 23.5 m recovered).

Core #2 was cut in Early Aptian sediments and consists primarily of dark grey calcareous shale with minor siltstone. A portion of Core# 2 is shown in Figure 81. Note the 0.5m interval of siltstone with shale laminae present on the far right of the photograph. Biostratigraphic analysis suggests these sediments were deposited in 100–200m of water, i.e. in an outer shelf setting (prodelta shales and siltstones?) (Robertson Research, 2000b).

Figure 81. Tantallon M-41: Portion of Core #2 (4689.0 – 4717.0 m, 28.0 m recovered).

Core #3 was cut in Hauterivian age dark grey calcareous shale with thin calcareous siltstone and very fine-grained sandstone laminae. A portion of Core# 3 is shown in Figure 82. Biostratigraphic analysis interprets these sediments as being deposited in an outer shelf setting in a water depth range of 100–200m (Robertson Research, 2000b). The “thickest” sandstone units, recovered in all three Tantallon cores, are shown in Figure 83 which is a close-up of a portion of Core# 3 (depth ~5300m). At the bottom are two very fine-grained sandstones units are present. Note the sandstone bed on the lower right is approximately 3cm thick.

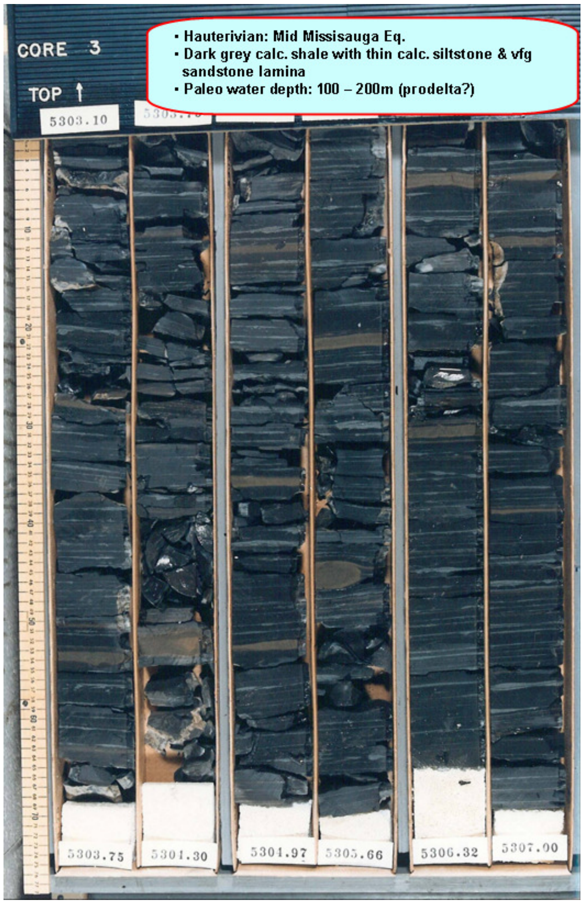


Figure 82. Tantallon M-41: Core #3 (5294.0 – 5313.0 m, 16.3 m recovered).

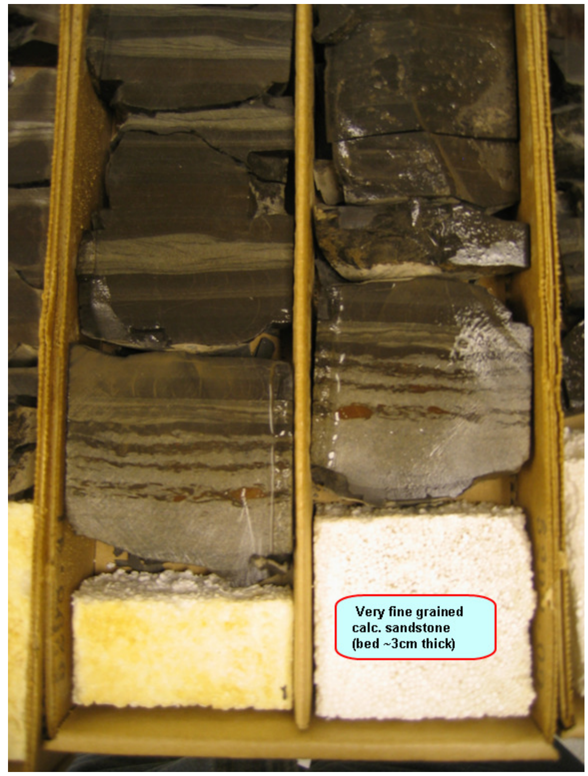


Figure 83. Tantallon M-41: Core #3 (~ 5300 m), close up of sandy intervals.

Seismic Interpretation

The Tantallon structure is defined by a Middle Cretaceous marker as observed in the time map (Figure 84) though closure is not present in the overlying Santonian-Maastrichtian Wyandot formation. Study of the feature suggests the possibility that the structure existed with positive paleotopographic relief prior to sand deposition and was therefore a sand bypass zone (Figure 85). The seismic data quality is poor in the deeper portion of this line, however, there is thinning evident in the upper Cretaceous section while some parallel bedding is present in the lower Cretaceous section. Together, this indicates that while the Late Cretaceous may have been in a sand bypass zone, the lower section may not have been. Once again, it would appear that the risk was not in the ability to map a structure but predicting the presence of reservoir sands within the structure. The synthetic well tie to the seismic reveals the poor correlation between the well and seismic.

Biostratigraphy

The Tantallon M-41 well is the easternmost deep water test in the Sable Basin and to the east of the Sable delta system. For the biostratigraphic study (Robertson Research 2000b), well samples were initiated within shales and minor siltstones and sandstones in the top Banquereau formation (Pliocene to Late Miocene). This section rests on the ubiquitous Mid Miocene uncomformity that eroded older Miocene to Late Oligocene (Chattian) sediments (Enclosures D, E). The Early Eocene unconformity is also observed representing a time gap of about 5 my. Thick chalks and marls (Wyandot) dominate the top Cretaceous interval and rest unconformably on shales and silts of the upper Logan Canyon formation. This Late Campanian to Early Turonian event removed the entire Dawson Canyon equivalent with a resulting 22 my time gap. The Logan Canyon sequence was deposited as an uninterrupted succession of shales (not calcareous) with minor siltstones. The basal part of the Naskapi member (Logan Canyon) and top-most Missisauga formation are absent in the well (Mid-Late Barremian). The remaining 600m of upper to lower Missisauga shales and minor silts and sands were deposited without any internal erosional events, with the oldest sediments dated as Late Valanginian.

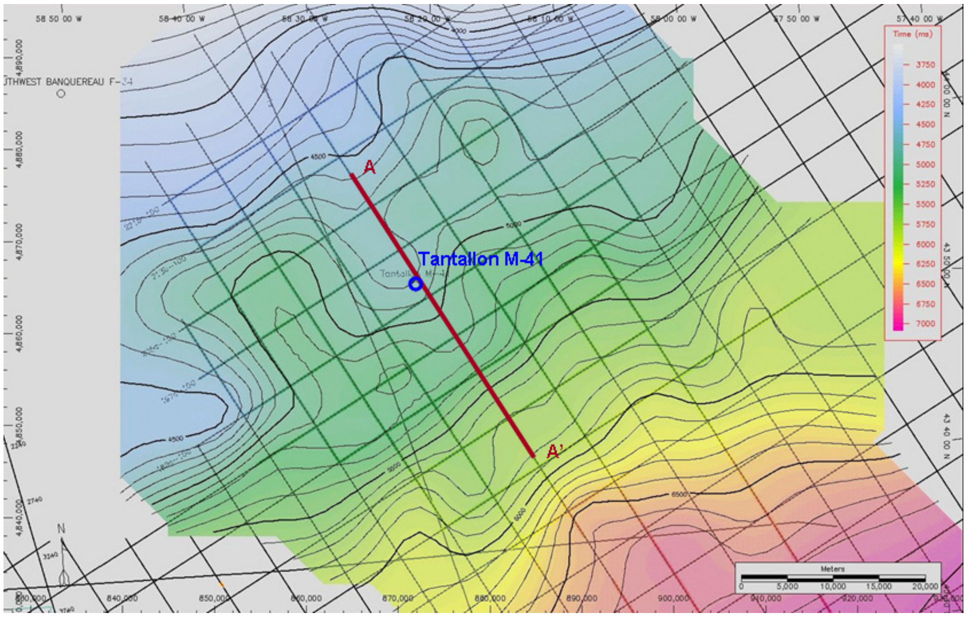


Figure 84. Regional 2-D seismic over Tantallon M-41. Line A-A' is shown in Fig. 85.

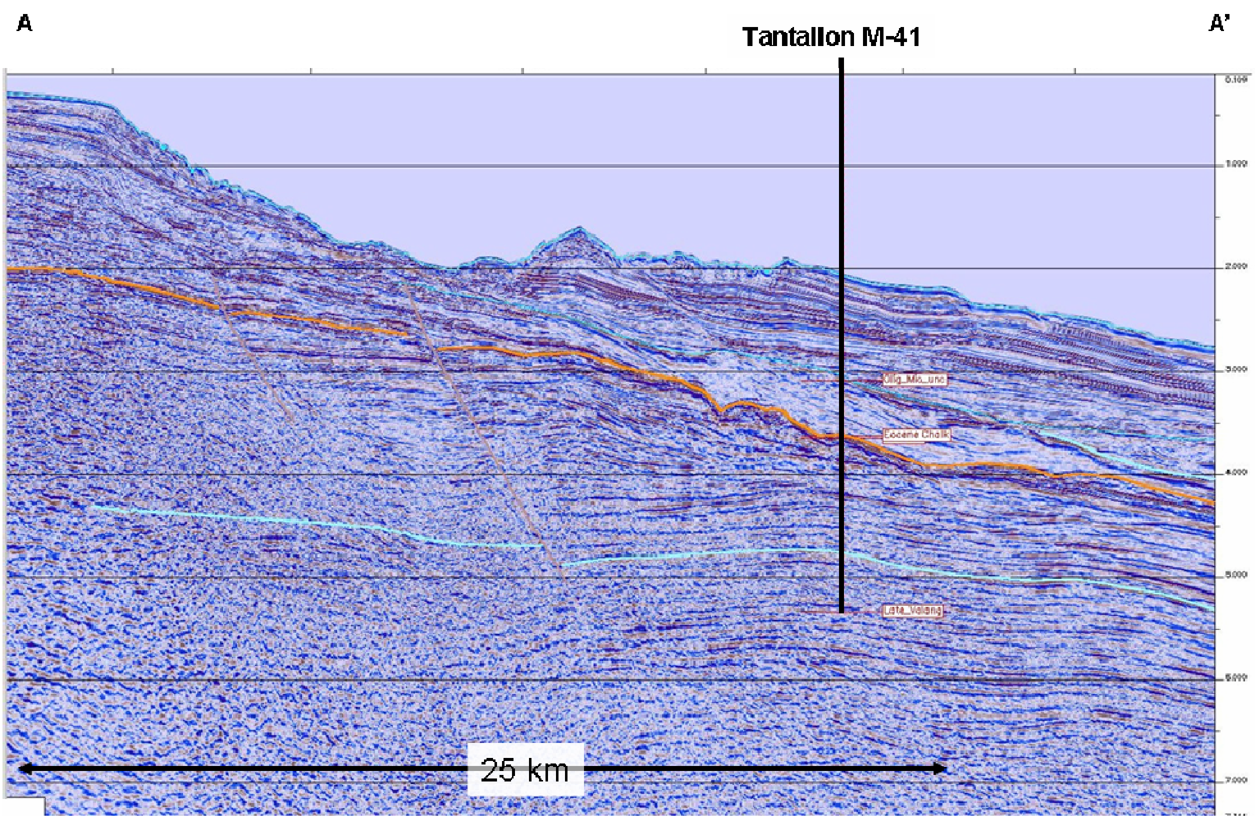


Figure 85. Modern regional 2-D seismic dip line through Tantallon M-41. Data courtesy of TGS-NOPEC.

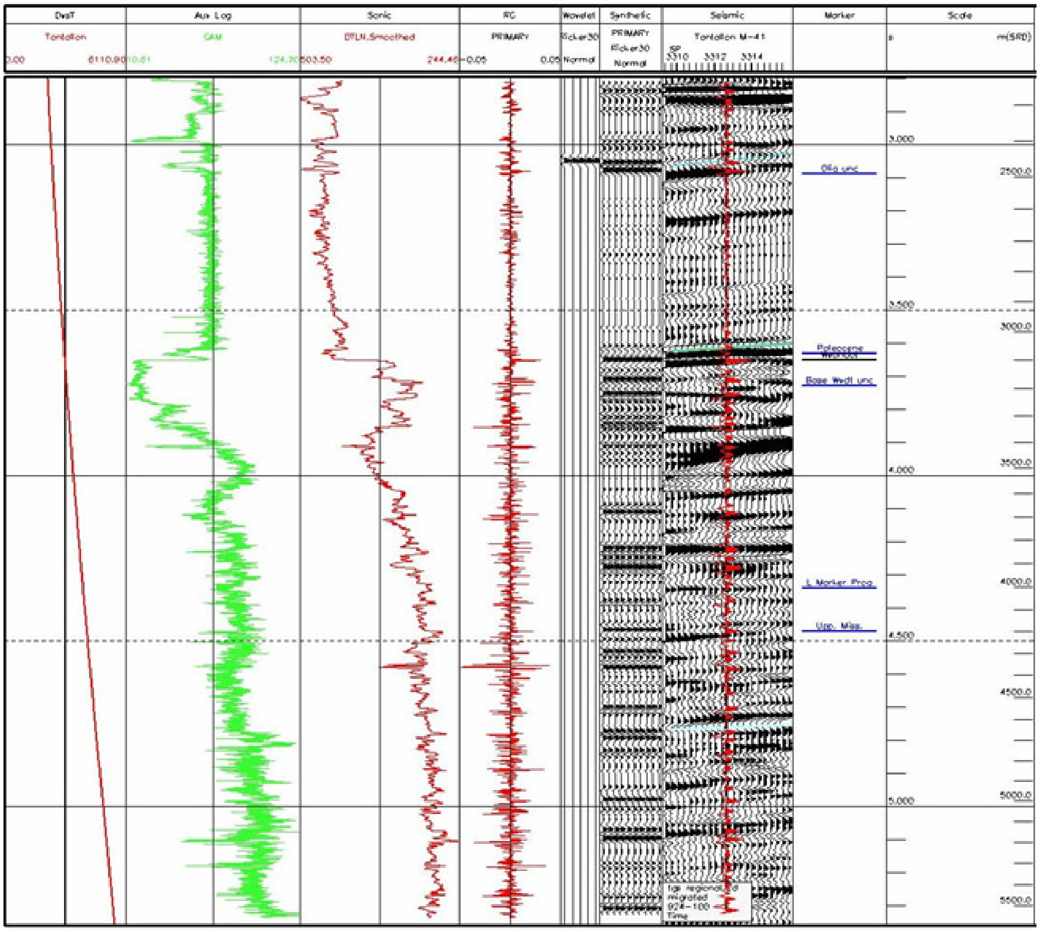


Figure 86. Tantallon M-41: Synthetic seismic.

Paleoenvironment

Interpretation of paleoenvironments in the Tantallon well was made by the Geological Survey of Canada (Thomas, 1991; and Williams, 1992) and Robertson Research (2000). Only the Tertiary and top Cretaceous section was studied by the GSC. Thomas (1991) based his interpretation on microfossils. Pliocene and Late Miocene sediments (above the Mid Miocene unconformity) were considered to have been deposited in an outer shelf to upper slope setting, with the underlying early Oligocene strata probably laid down on the upper slope. The remaining Eocene to Maastrichtian interval was interpreted as being deposited in outer shelf to upper slope conditions. Williams (1992), based on palynomorphs, concluded that the entire Tertiary succession was deposited mostly in outer shelf to upper slope environments. A later synthesis by Wade et al. (1995) reevaluated the M-41 well and considered all the Tertiary strata to have been deposited in the outer shelf to upper slope. Recent study of the well by Robertson Research (2000) focused only on the Cretaceous section. Cenomanian (Logan Canyon) to latest Aptian were mostly deposited on the outer shelf to upper slope with the Late Aptian (Cree member) restricted to the upper slope. The remaining Early Aptian to Valanginian (Missisauga formation) occupied a outer shelf location with microfossils dominated by allochthonous remains.

Geochemistry

Geochemical source rock analysis and organic matter typing for this well is not yet available. However, it is likely that the sediments contain Type IIA-B/III organic matter common to the Verrill Canyon formation elsewhere in the Scotia Basin.

Depth (m)	Formation	Age	Vitrinite Reflection (% Ro)	Maturity for oil generation
1516	Sea Floor	Recent	(0.25)	n/a
3187	Wyandot	L. Cret. (~Maastrichtian)	0.4	immature approaching maturity
4002	Lower Logan Canyon (~Cree Mbr.)	E. Cretaceous (L. Aptian)	~0.5	marginally mature
4668	Lower Logan Canyon (Naskapi)	E. Cretaceous (E. Aptian)	0.6	moderately mature
5602	~ Middle Missisauga	E. Cretaceous (L. Valang.)	0.77	moderately mature

Table 5. Thermal maturation levels for the Tantallon M-41 well (Avery, 1991). Note that the value for the seafloor in brackets was calculated from the derived / extrapolated Ro slope of 0.119 log Ro/km. This rate is lower than that for similar wells located on the western Scotian Slope, e.g. Shubenacadie H-100 (0.153) and Shelburne G-29 (0.128) which infers a lower geothermal gradient and deeper petroleum generating windows.

Exploration Implications

In hindsight, the lack of sand is not surprising since this well was beyond the shelf environment and perhaps not far enough to intersect any submarine fan sands. Alternatively, this area could have been a bypass zone. Perhaps more importantly, the Tantallon structure exhibited no growth interval within the target zone. The 2D seismic data quality from 20+ years ago was sufficient for structural mapping, but not for seismic sequence analysis or seismic attribute extraction. Furthermore, the degree of basin evaluation of this well is minimal.

5.4.3 Well Operations

The only major operational problem experience in Tantallon M-41 was the drill string becoming stuck at 3907m. Attempts to free the string were unsuccessful. It was backed off at 3854m, a cement plug set, and the well was sidetracked around the fish. The total lost time from this operation was 4.6 days. Pre-spud it was estimate it would take 72 days to drill and abandon the well (Figure 87). However, since no kicks or abnormal pressures were encountered, drilling rates were faster than expected and only a few days were lost due to operational problems. The well was drilled and abandoned in only 63 days (9 days less than AFE).

5.4.4 Risk and Assessment

The Tantallon M-41 well lies south of modern Shortland Canyon in the northwest part of the Salt Withdrawal Area #3 as defined by the Board's 2002 assessment. The Board's play adequacy was deemed to be 20% based on:

- Source 70%
- Reservoir 40%
- Trap 70%

The prospect adequacy was also 20% for an overall adequacy of 4% or 1:25. The objective of the well was to test for turbidite sands. However, the interpretation of the anomaly is not sufficient to cause any changes in the assessment parameters in this area.

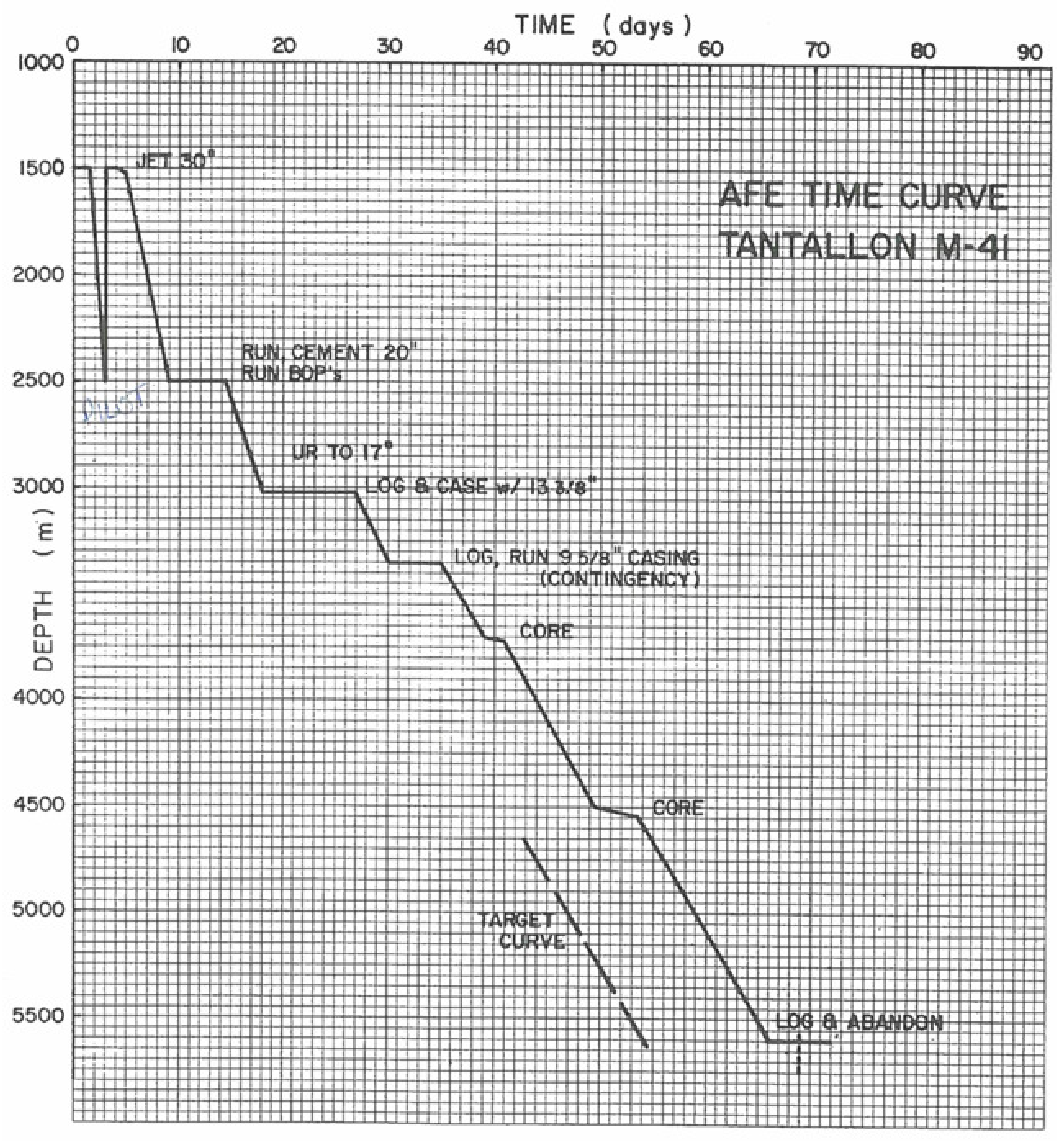


Figure 87. Tantallon M-41: AFE Time vs. depth curve (actual not available).

5.5 Marathon Annapolis B-24/G-24 (2001-02)

Marathon spudded the first of the recent deepwater wells off Nova Scotia at the B-24 location in 1740 metres of water using the West Navion drillship. It was spudded on December 26^{h}, 2001 but encountered major mechanical problems with the riser and sheaves and a major gas kick at 3496m (near top of the Maastrichtian Wyandot formation chalks) which resulted in the drillpipe getting stuck and the eventual loss of the well. The B-24 location was abandoned and the drillship moved about 900 metres to the northwest to the G-24 location which was spudded on April 17, 2002. The rig was released on August 16, 2002 and suspended as a gas well (Enclosure A).

5.5.1 Objectives and Concepts

The main objectives were Early Cretaceous (Upper Albian to Lower Aptian) lowstand, deep water turbidite sands within a large structural closure formed as a result of adjacent salt withdrawal and listric down-to-basin faulting (Figures 88 & 89). The operator undertook an extensive sequence stratigraphic study of shelf wells but any direct link from shelf to slope remains unknown. The mud/sand-rich model of Reading and Richards (1994) is believed to represent the depositional analogy for this prospect (Figure 9).

Prior to Annapolis G-24, the Tantallon M-41 well (1986) was the only other well that penetrated the Cretaceous deepwater sediments on the Scotian Basin. Thus, without any direct correlation of sands beyond the shelf break, reservoir prediction was based generally on proximity to the sand-rich Sable area and specifically with seismic character attributes.

A regional 3D seismic line through the Annapolis (and Crimson) anomalies is shown in Figure 90. The dip of the Tertiary strata is a major aspect of this part of the slope and the degree of Late Cretaceous/Early Tertiary "downcutting" is not defined. Both 2D and 3D seismic was used to define the play with reservoir prediction from on 3D-derived seismic properties and reflection patterns. The operator's geological risking values are not known.

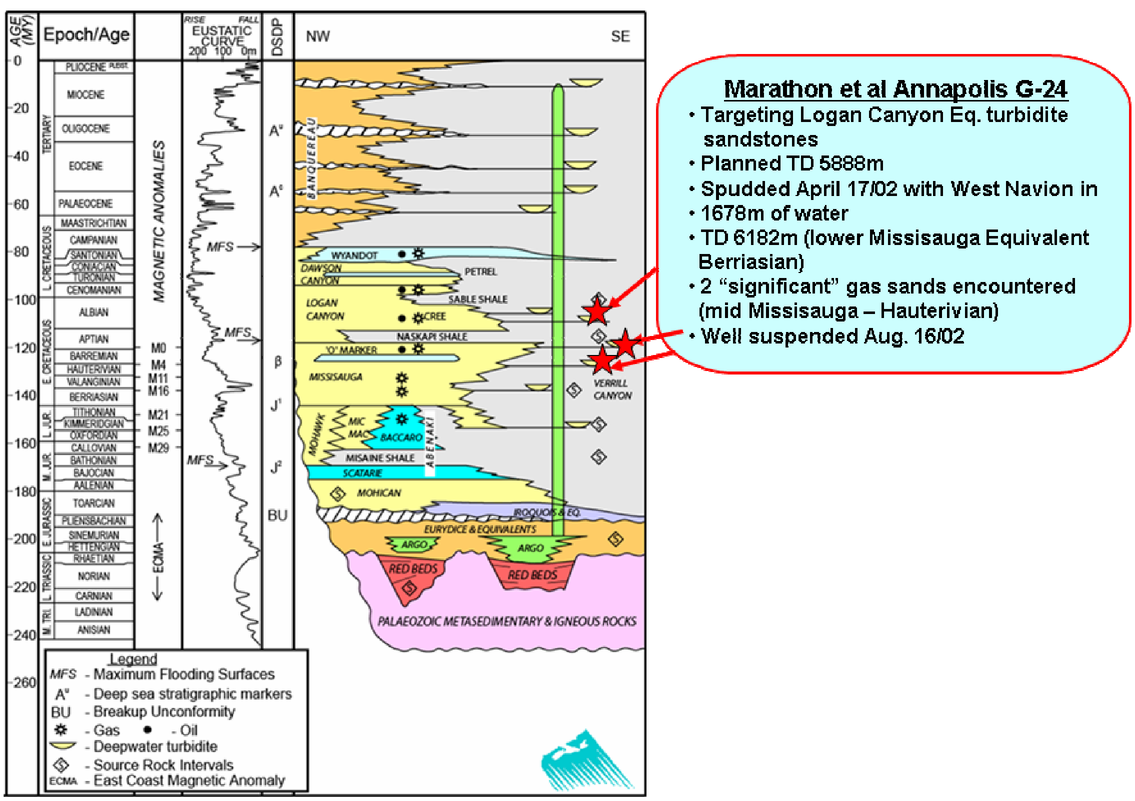


Figure 88. Stratigraphic chart showing target intervals for Annapolis G-24.

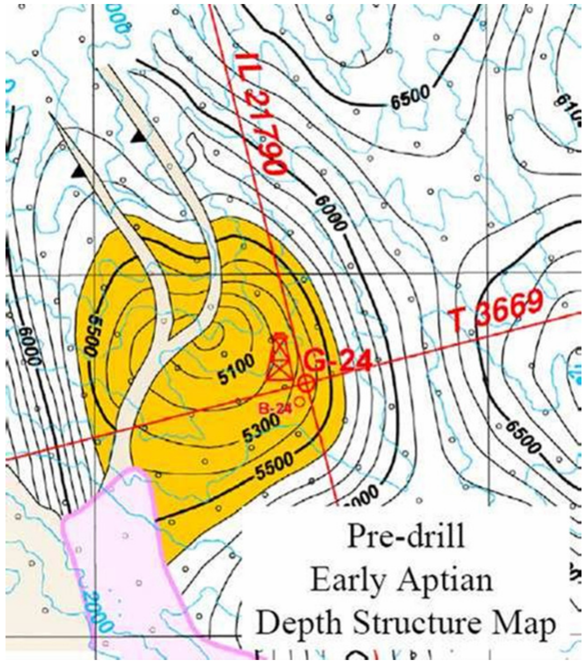


Figure 89. Annapolis G-24: Early Aptian Depth Structure Map (Annapolis ADW, used with permission).

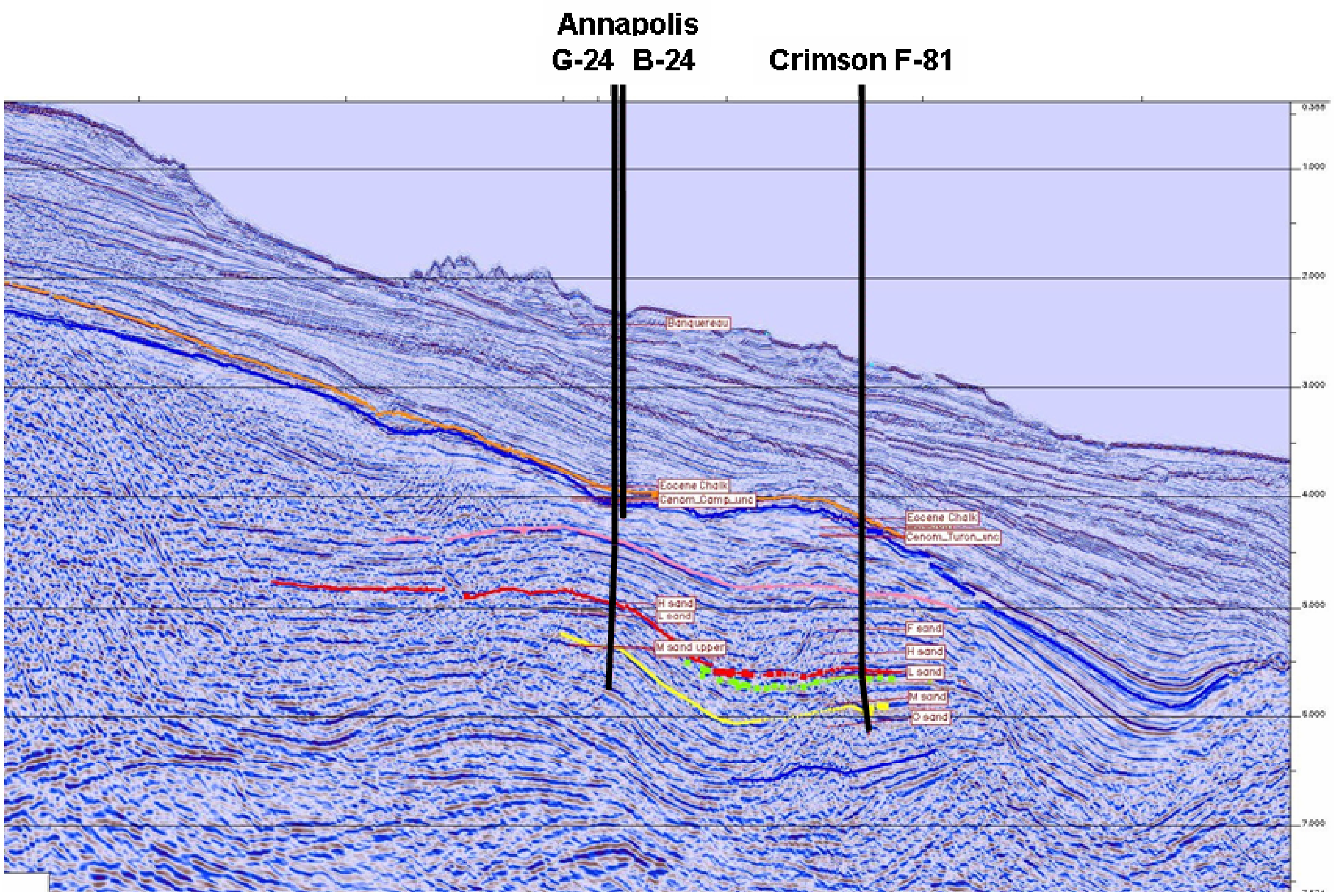


Figure 90. Profile through the Annapolis and Crimson structures. Data courtesy of CGG-Veritas.

5.5.2 Results

Drilling:

The Annapolis G-24 well was drilled to a TD of 6182m MD (planned TD 5888m) in the lower Missisauga formation equivalent section (Late Berriasian) (Enclosure B). Three main gas bearing zones were encountered from 4842–5528m MD designated by the operator as the H, L and M Sands (Marathon 2002). It should be noted that the H and L "sands" are not individual sand units but gross intervals which consist of interbedded sands, siltstones and shales.

The H Sand interval extends from 4842–4866m MD and is Mid Barremian age (upper Missisauga equivalent) (Marathon, 2002). It consists mostly of interbedded shales, silts and minor sands. There is a cumulative total of 3.8m net pay across the entire interval summed from a number of very thin sands less than 1m thick (Figure 91).

The L Sand interval extends from 5040.5–5097.8m MD and is also Mid Barremian age (Marathon, 2002). It is lithologically similar to the H Sand except the sand/silt ratio is higher. The zone has a total of 5.3m of net pay over a 57.3m gross interval (Figure 92). The reservoir quality of the L Sand is also better with an average net pay porosity of 17% compared to 14.8% for the H Sand.

The main reservoir zone in the Annapolis G-24 well is the M Sand interval (Late Hauterivian, middle Missisauga equivalent) (Marathon, 2002) that consists of two sands with fair to very good porosity with a total of 18.2m of net gas pay (Figure 93). The two sands were arbitrarily named M Sand-upper and M Sand-lower and have a porosity range of 12–25% and fair to very good permeability, based on MDT mobilities ranging from 0.4–132 mD/cp.

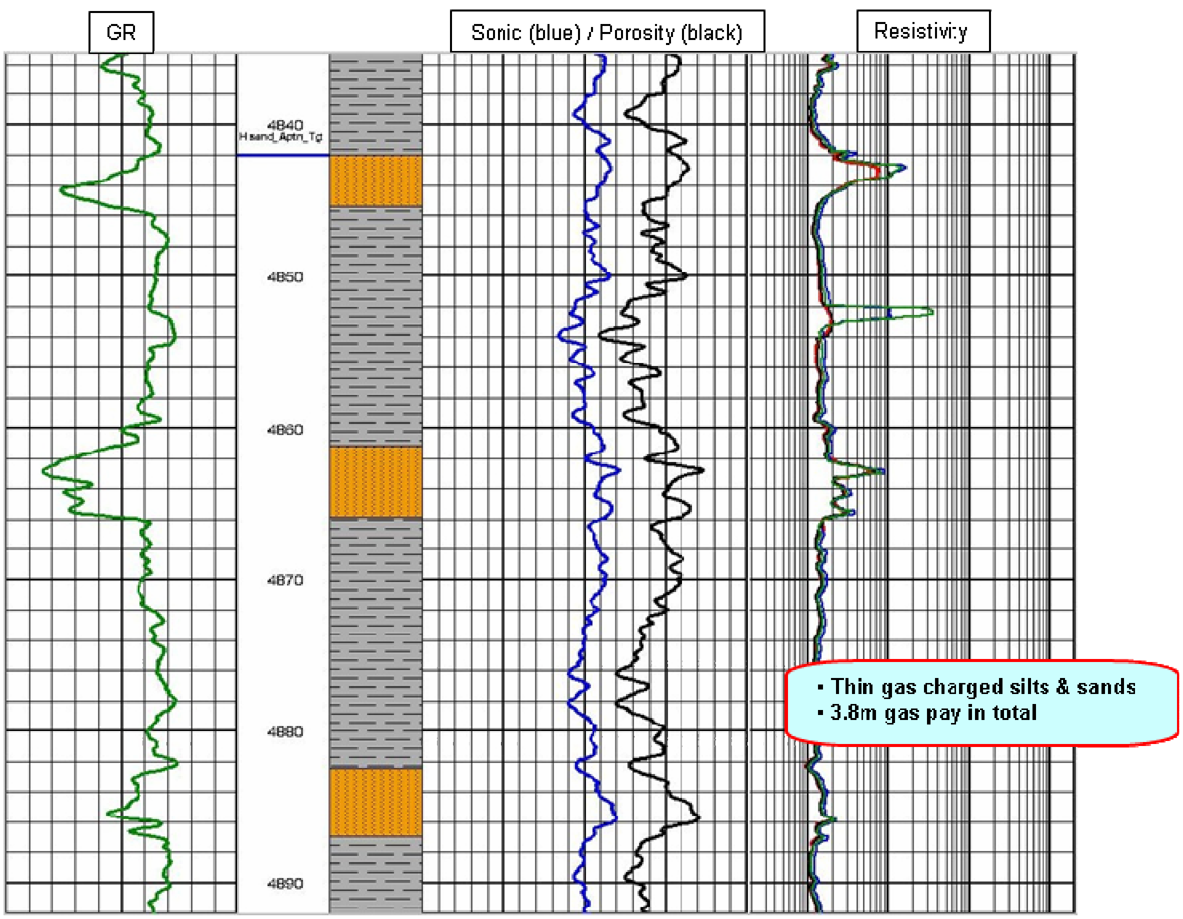


Figure 91. Annapolis G-24: Well logs from the H Sand interval (Barremian).

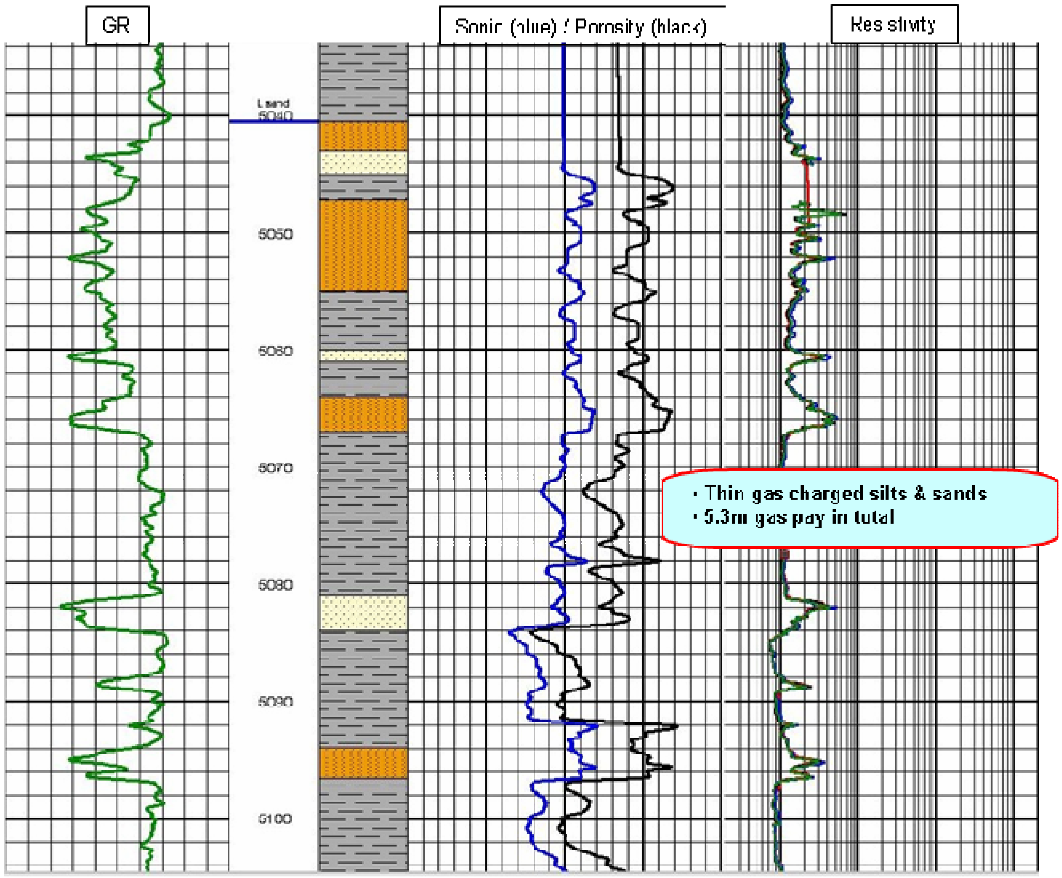


Figure 92. Annapolis G-24: Well logs from the L Sand interval (Barremian).

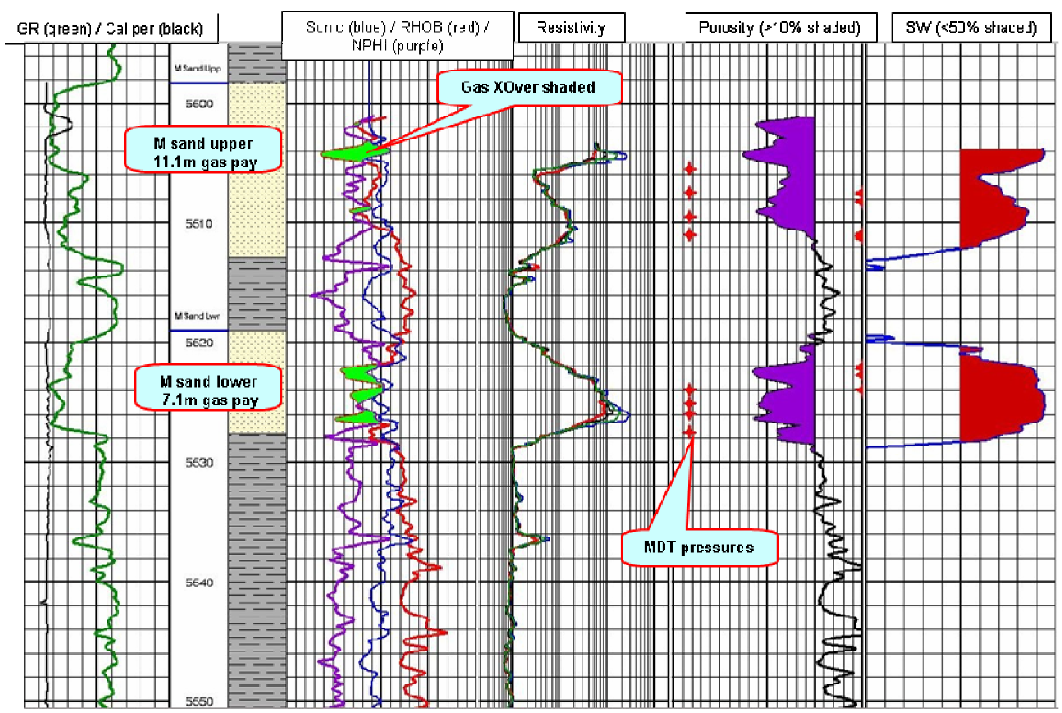


Figure 93. Annapolis G-24: Well logs over the M Sand interval (Hauterivian).

Zone	Top (m MD)	Base (m MD)	Net Pay (m TVD)	Net Pay Por. (%)	Sw (%)
H Sand	4842.0	4866.0	3.8	14.8	50
L Sand	5040.5	5097.8	5.3	17.0	43
M Sand-Upper	5498.3	5513.0	11.1	17.4	19
M Sand-Lower	5519.0	5527.5	7.1	17.6	14
Total			**27.3**		
Net Pay Cutoffs: Vsh <= 40%, Por. >= 10%, Sw <= 60%					

Table 6. Annapolis G-24 Reservoir Properties (CNSOPB)

Calculated reservoir properties for G-24 are tabulated above (Table 6). It should be noted that while net pay was calculated in the H and L Sand intervals, they consist of very thin individual sands interbedded with shales and tight siltstones. They would be unlikely to produce gas at sustained rates and therefore it is questionable if they should be recognized as pay zones. The M Sands however, are of good quality, are relatively thick, and should be considered high confidence gas pay.

MDT pressure data was acquired in the M Sands and is plotted in Figure 94. The MDT pressures for each sand lay on a gas gradient that confirms the zones are gas bearing. The M Sand-upper has a pressure gradient of 3.32 Kpa/m while the M Sand-lower has a gradient of 2.66 Kpa/m with the difference suggesting separate gas pools. When a single pressure gradient is fit to the data, a gradient of 5.35 Kpa/m is obtained. However, this is not a valid gradient for either oil, water or gas but supports the presence of two separate gas pools. Using indicators such as mud weight increases in response to increasing connection and trip gas, sonic and resistivity log trends, etc., the top overpressure was estimated to occur at approximately 3300m TVD.

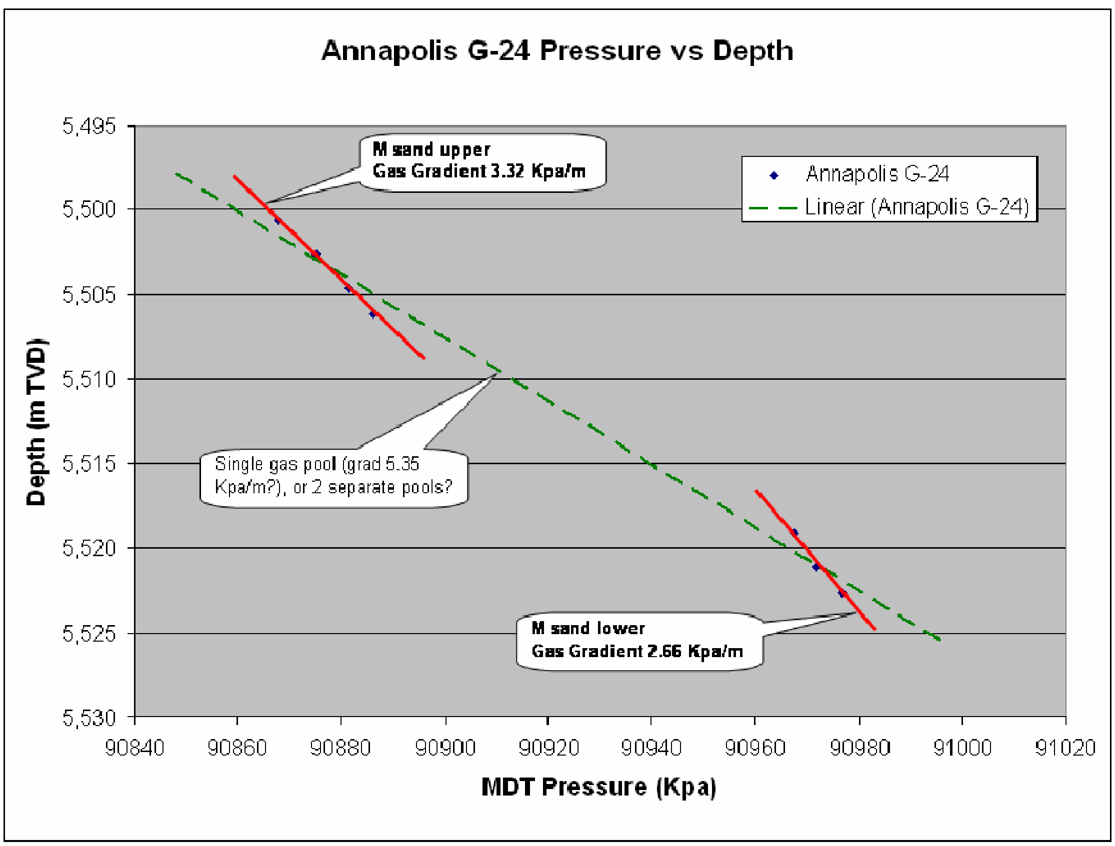


Figure 94. Annapolis G-24: Pressure versus depth plot for the M sands (MDT pressures).

Seismic Interpretation:

Figure 90 displays a CGGVeritas 3D regional composite line through the Annapolis and Crimson wells. It is difficult to correlate the Crimson F Sand pick with strata in the Annapolis G-24 well. Even the 3D data is noisy in the deeper portion of the section. Figure 95 provides a detailed view of the well on Marathon's reprocessed 3D data which has better preservation of the relative amplitudes. The reflections are weaker and not as continuous below the H Sand and none of the sands stand out as major seismic events.

Figure 89 presents Marathon's pre-drill depth map on the Early Aptian. The well was targeted away from the structural crest but into a thicker stratigraphic section. The interpreted seismic-derived "geobodies" turned out not to be indicative of the presence of sand, but calibration of the seismic response with the well results will be very useful in the future. The synthetic seismic well-tie in Figure 96 is shown to be good in the upper part of the well but deteriorates with depth because unlike the synthetic, the seismic degrades in frequency content.

Biostratigraphy

A detailed biostratigraphic study was completed by Robertson Research (2002) for the well operator. Within the Tertiary sediments in the Annapolis B-24 and G-24 wells, biostratigraphy indicates several minor time gaps from the Early Oligocene to Middle Paleocene (Enclosures D, E). There is a pronounced unconformity between the basal Paleocene mudstones and underlying chalks of the Wyandot formation, with an about 11 my time gap (Early Paleocene to Late Campanian). A thin part of the Wyandot is present and unconformably overlies the Logan Canyon formation (Sable member), with this second major time gap lasting about 17my from the Early Campanian to Late Albian. Except for a minor hiatus in the Middle Aptian, the remaining Cretaceous Naskapi to lower Missisauga sequence is essentially complete down to the Late Berriasian.

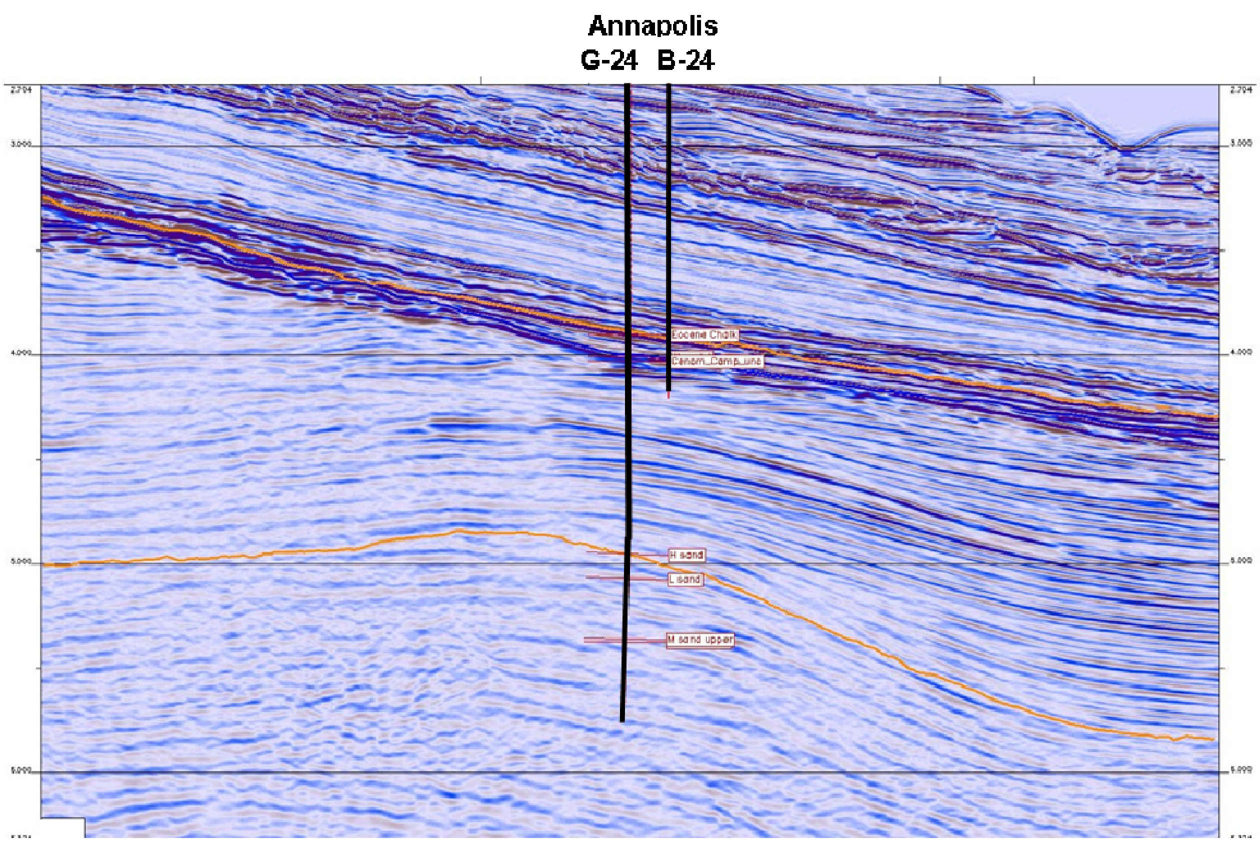


Figure 95. Detailed profile of the Annapolis structure (zoomed in relative to Figure 90). Data courtesy of CGG-Veritas

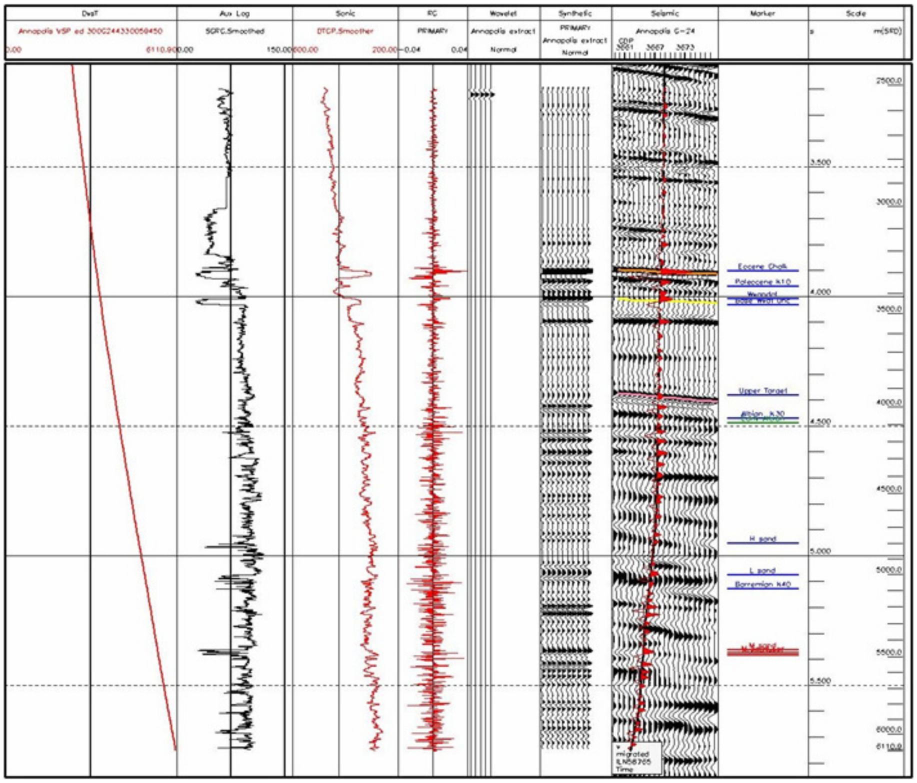


Figure 96. Annapolis G-24: Synthetic seismic.

Paleoenvironment

Paleoenvironmental determinations of depositional settings reveal that the entire Tertiary succession was deposited close to the shelf/slope break and reflects an outer shelf to upper slope position (Robertson Research, 2002). Wyandot chalks represent a condensed section deposited under well-oxygenated, outer shelf conditions. The unconformable, underlying Logan Canyon (Cree member) was also deposited in the same setting.

The majority of the Cretaceous sequence, including most of the targeted potential deep water reservoir zone, was deposited in a outer shelf environment. Some Early Aptian to Late Barremian (upper Missisauga formation) sediments are interpreted to have been laid down in an upper slope position. The pay sands found in this well were located within this interval.

Geochemistry

A comprehensive geochemical analysis of the G-24 and B-24 wells was completed for the operator by Global Geoenergy Research (2002a). Throughout the evaluated section, there were considerable amounts of allochthonous (transported) kerogen. For valid results, analysis was conducted only on autochthonous (in-situ) material.

The analysis indicated that most sediments have more than 0.5% TOC and are capable of generating hydrocarbons. Sediments between 4000-4500m (Naskapi member) and 5800-6200m (lower Missisauga formation equivalent) are considered organic rich with more than 2.0% TOC. All sediments below 5200m lie within the ‘principle phase of oil and gas generation. For the entire well, the organic matter was gas- and condensate-prone Type II-III.

The Tertiary and Late Cretaceous stratigraphic section above approximately 4500m is considered immature, and between 4500-5000m the lower Logan Canyon and Naskapi sections are marginally mature and within the very early phase of oil generation. Middle and lower Missisauga formation sediments from about 5200m to 6182m (well total depth) are identified as being in an advanced maturity state and plot well within the phase of maximum oil generation.

Depth (m)	Formation	Age	Vitrinite Reflection (% Ro)	Kerogen Type	Maturity for oil generation
1752	Sea Floor	Recent	n/a	n/a	n/a
2555 - 3590	Banquereau	E. Oligocene (Rupelian) – E. Paleocene (Danian)	~ 0.2 - 0.4	(II)-III	immature
3590 - 4575	Wyandot to Logan Canyon (Naskapi Mbr.)	L. Cret. (L. Campanian) to E. Cret. (E. Aptian)	~ 0.40 – 0.45	(II)-III	moderately immature
4575 - 5000	Logan Canyon (Naskapi Mbr.) to U. Missisauga	E. Cretaceous. (Aptian to M. Barremian)	~ 0.45 – 0.6	(II)-III	marginally mature to mature
5000 - 6182	Upper to Lower Missisauga	E. Cretaceous (M. Barremian to L. Berriasian)	0.6 – 1.04	(II)-III	mature to late mature

Table 7. Thermal maturation levels and kerogen types for the Annapolis G-24 well (Global Geoenergy Research, 2002a). Ro values are ranges for the respective interval.

Exploration Implications

Results from the Annapolis well are the most encouraging well to date and confirm the general concept that deep water sands were deposited in front of the Sable paleodelta. However, the prediction of sand thicknesses from seismic attribute analyses was tenuous. The target section was older and deeper than expected and the well bottomed in lower Cretaceous Valanginian rather than Barremian age sediments. From this single data point, reservoir facies determination within the conceptual submarine fan body is not certain. Details regarding shelf to deepwater transport and deposition and facies distribution remain unknown, but available information suggests that the Annapolis area may represent an overall bypass zone.

The two-fold challenge of restoring present-day structural configurations to syndepositional conditions, and the prediction of hydrocarbon bearing reservoirs from seismic attributes, has been attained to a certain degree. This subsurface calibration for both the geologic and seismic models is critical in the ultimate unravelling of the deepwater slope depositional facies.

The interpreted outer shelf environment for the Cretaceous implies a much broader shelf than ever suspected given the position of the Late Jurassic margin at 144 mya and the location of the present-day margin (Enclosure A). It is more likely that the range of depositional environments varies between outer shelf to upper bathyal and covers very broad areas.

5.5.3 Well Operations

The Annapolis B-24 well was the first well spudded on the Annapolis prospect. Significant operational difficulties and delays occurred after the 13 5/8"/346mm surface casing was run and cemented. These delays included significant mechanical problems with the rig's riser, ram rig and sheaves that resulted in a total of 79 days of lost time. After drilling resumed and while drilling in the 12 ¼"/ 311mm hole section, a major gas kick (76 m^3 pit gain) occurred at a depth of 3495.7m near the base of the Tertiary. As a result, the drill pipe became stuck and the well was eventually abandoned. A total of 25.4 days were spent killing the well, attempting to free the pipe and abandoning the well. When all delays are included (i.e. major and minor) a total of 95.6 days of lost time was experienced in the B-24 well. Pre-spud, it was estimated that the B-24 well could be drilled and abandoned in 63 days, however after 132 days the well was abandoned at a depth of 3495.7m, well above the target section.

The subsequent Annapolis G-24 well was moved about 900m northwest of the B-24 location and spudded very shortly after B-24 was abandoned. It was targeting the same subsurface objectives as B-24. G-24 experienced a total of 47.3 days of operational delays related to repairs to BOP and ram rig unit, drill pipe washout, lost circulation zones, cement squeezes, minor gas kick and logging difficulties (Figure 97). An extra casing string was run near the base of the well, and allowed the well to be deepened to 6182m MD, 294m below the planned TD. In general, Marathon's pre-spud estimate of the fracture gradient of the formations was fairly consistent with the leak-off tests conducted in the well; i.e., a fairly accurate pre-spud prediction of rock strength. Annapolis G-24 was drilled and suspended in 129.6 days while the pre-spud estimate was 62 days (Figure 97). Marathon decided to suspend G-24 to preserve the ability to re-enter the well in the future.

5.5.4 Risk and Assessment

Annapolis lies within the Central Upper Slope (Play #11) of the Board's 2002 assessment. The play adequacy was 64% and consisted of:

- Source 100%
- Reservoir 80%
- Trap 80%

The prospect adequacy was 25% for an overall adequacy of 16% or 1:6.

The results of the well suggested the reservoir input parameters were too optimistic. For the revised assessment, the play level the reservoir adequacy, which includes the ability to detect reservoir, was reduced from 80% to 50% (see Section 7.2). At the prospect level, the net pay thickness distribution and the drilling success ratio were commensurately reduced.

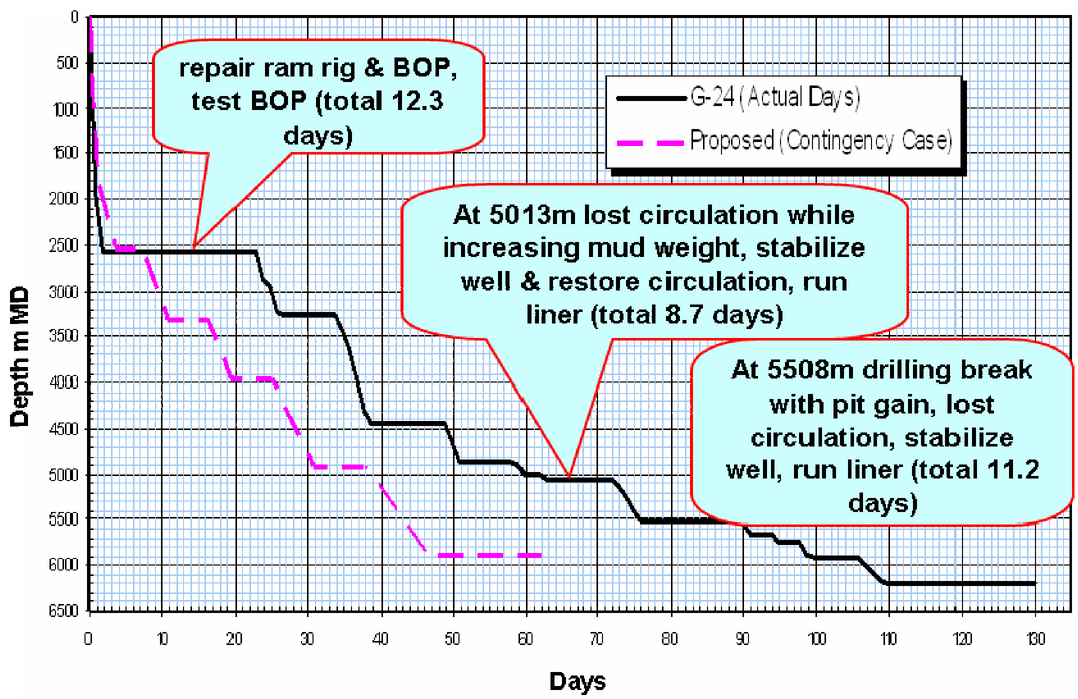


Figure 97. Drilling curve for Annapolis G-24 (AFE and actual).

5.6 Chevron Newburn H-23 (2002)

Chevron's entry well in the deepwater at Newburn H-23 was spudded in 977m of water on May 22, 2002 using the Deepwater Millennium drillship and was abandoned on August 21, 2002 (Enclosure A).

5.6.1 Objectives and Concepts

Newburn's objectives were postulated deepwater turbidite sands deposited during Early Cretaceous sea-level falls (Figure 98). These sands were expected to be the lowstand equivalents of the top Missisauga formation deltaic sands that are significant gas reservoirs in the Thebaud, Venture and other gas fields in the Sable Island area.

The H-23 location lies 17km southeast of the Evangeline H-98 well (Figures 57 & 62). Evangeline bottomed in upper Missisauga formation-equivalent shales at 5044m (Figure 63). Prior to Evangeline, Newburn's targeted Early Cretaceous interval had not yet been penetrated offshore Nova Scotia and were stratigraphically deeper than H-98's FTD.

Study of the seismic dataset reveals that the Newburn structure appears to be a large detachment fold developed at the toe-of-the-slope (Figures 98 and 99). Presumably, adjacent salt withdrawal played a large part in the formation of this interpreted gravity-slide feature and its related depositional history. The well was drilled in a down-flank position apparently to coincide with isopach thicks having seismically defined (amplitude) stratal geometries consistent with interpreted turbidite depositional systems (Figure 100).

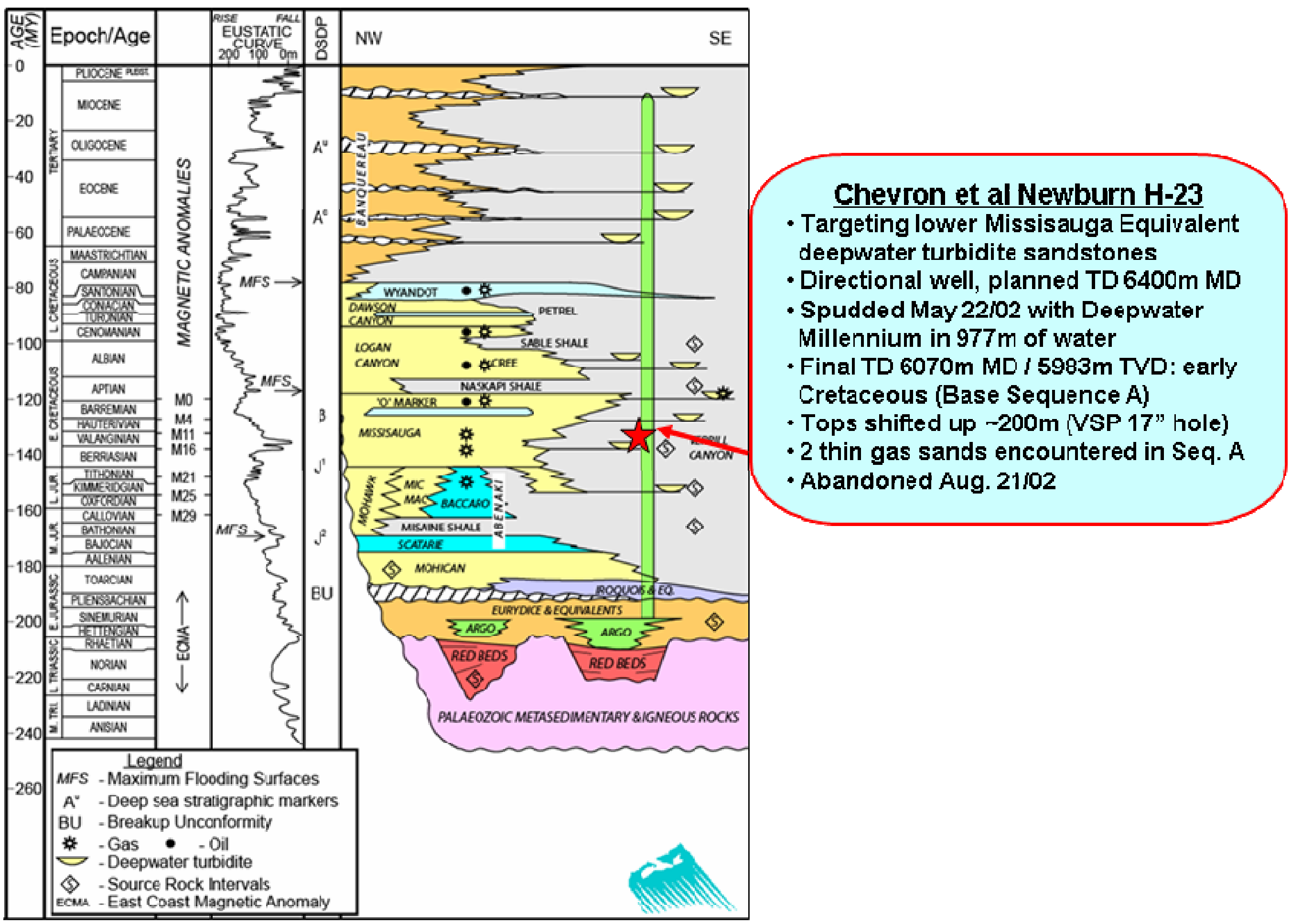


Figure 98. Stratigraphic chart showing target interval for Newburn H-23.

The prospect was mapped using a large 3D survey recorded in 2000 and processed to PSDM (Figure 99). There was no local well control at this position on the slope to calibrate the seismic amplitudes and velocities. Four sequences (D-A, descending) were delineated, with facies interpreted from seismic amplitudes and stratal geometries. The lower part of Sequence B was the primary reservoir target consisting of possible turbidite sand complexes (Chevron Canada Limited, 2002). The well would thus be an important test to assess reservoir and hydrocarbon pay attributes, calibrate seismic response, and constrain the geological model.

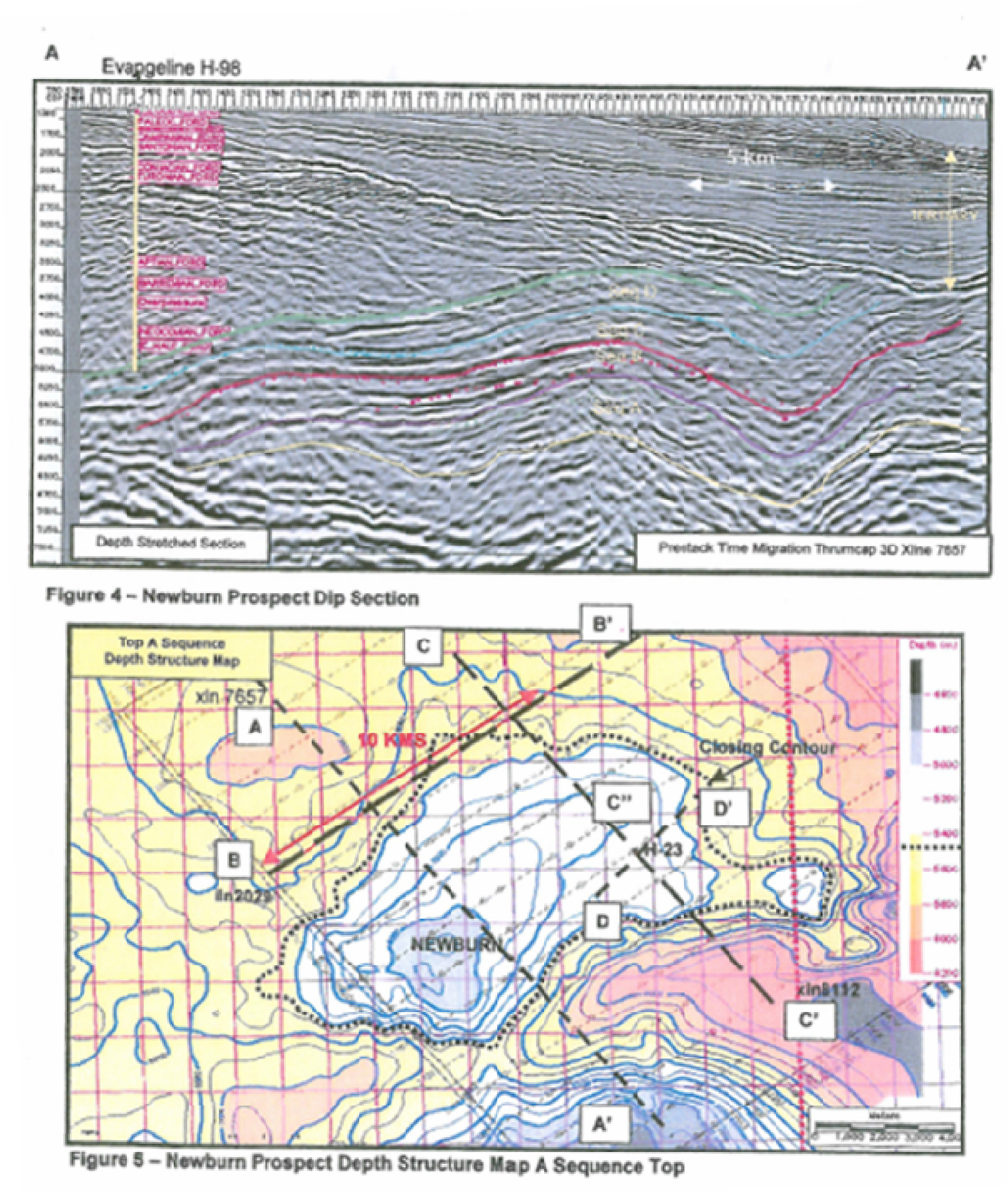


Figure 99. Key 3-D seismic line and Sequence A top depth structure map from Newburn H-23 ADW (used with permission).

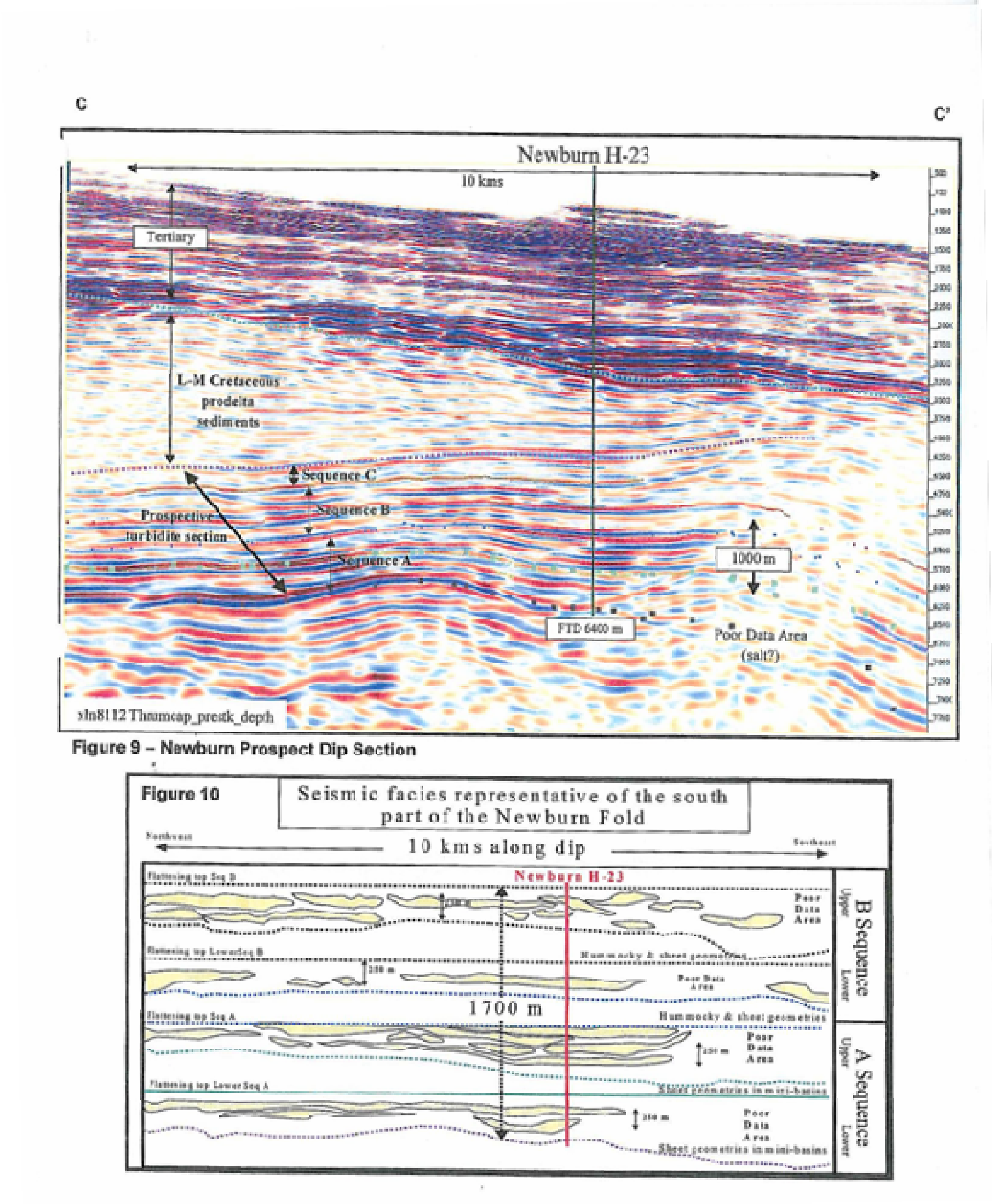


Figure 100. 3-D seismic dip section and interpreted facies for Newburn H-23, from the Newburn H-23 ADW (used with permission).

5.6.2 Results

Drilling

The well was drilled to a TD of 6070m MD / 5983m TVD in the Early Hauterivian (upper Missisauga equivalent). The original TD for the well was 6400m MD. However, it was shortened by 330m due to the results of a VSP in the 17"/432mm hole that indicated the tops were being encountered approximately 200m higher than prognosed (Enclosure B).

The stratigraphic position of the H-23 target section is shown in Figure 100. A few thin reservoir sands, some with gas pay, were found above and within the target section but the sands were thin and thus non-commercial. Four main zones of interest were identified in the well and from the shallowest to the deepest were arbitrarily designated Sands 1 to 4 (Figure 101). The reservoir properties of these sands are tabled below (Table 8).

Sand 1 (Figure 102) appears to be a 20m thick fining-upward channel sand with a quartz and lithic pebble conglomerate (lag deposit?) at the base (Figure 105). The zone has porosity from 9–21% (average 18%) though no gas shows were detected and the sand appears wet on logs.

Sand 2 (Figure 102) is a very fine- to fine-grained shaly sandstone which generated a significant gas show (2112tgu/200u). The zone has fair porosity (average 13.5%), high water saturation, and may have 2m of questionable gas pay.

Sand 3 is a possible channel sand. It is 6m thick and comprising of very fine- to fine-grained porous (19%) sandstones with 3m of net gas pay (Figures 103 & 105). The well took a gas kick at the top of the sand at 5405m MD that required several days to circulate out. Gas units ranged from 5800–6600tgu/200u.

Sand 4 is a thin 3m thick very fine- to fine-grained sandstone with 2.5m of net gas pay (Figure 104). The sand has fair porosity (net pay porosity 14%) with a relatively weak gas show of approximately two times background (104tgu/45u). The magnitude of the show was likely suppressed by the high mud weights used to drill this section.

Porosities obtained from core analysis of the rotary SWC acquired in Sands 1–4 are in good agreement with log calculated porosities (Table 8). Most SWCs had permeabilities less than 0.5mD, which is only slightly above the 0.1mD minimum "rule-of-thumb" permeability cutoff for gas reservoirs. However, four SWCs had permeabilities from 2–42mD that indicate some zones have good production potential, assuming adequate reservoir thickness is encountered. Twelve wireline formation pressures (MDTs) were attempted without success; 11 were lost seals and one was dry (tight).

The top of overpressure is difficult to determine due to the lack of porous and permeable sands in the up-hole portion of the well. Based on mud weight increases in response to rising connection/trip gas, the top of overpressure is postulated to occur at approximately 3800m MD.

Sand#	Top (m MD)	Base (m MD)	Net Pay (m)	Porosity (%)	Sw (%)	SWC Porosity (%)	SWC k (mD)
Sand 1	4305.5	4325.7	Wet?	18	Wet	8.9 - 18.1	<0.01 - 42.4
Sand 2	4348.5	4357.5	2.0	13.5	60	12.1 - 12.9	0.28 - 0.80
Sand 3	5402.0	5408.0	3.0	19	23	7.2 – 18.9	<0.01 - 6.43
Sand 4	5957.5	5963.5	2.5	14	28	8.8 – 13.3	<0.01 – 0.03
Net Pay Cutoffs: Vsh <= 40%, Por. >= 10%, Sw <= 60%							

Table 8. Newburn H-23 Reservoir Properties (CNSOPB)

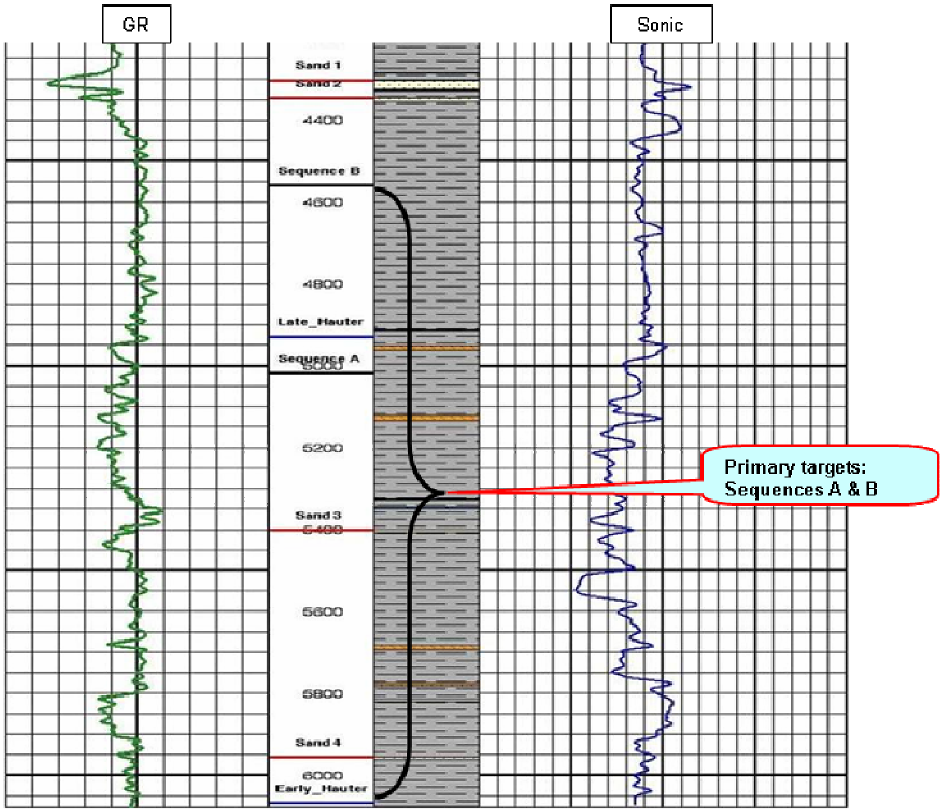


Figure 101. Newburn H-23: Well logs from the primary well targets (Hauterivian).

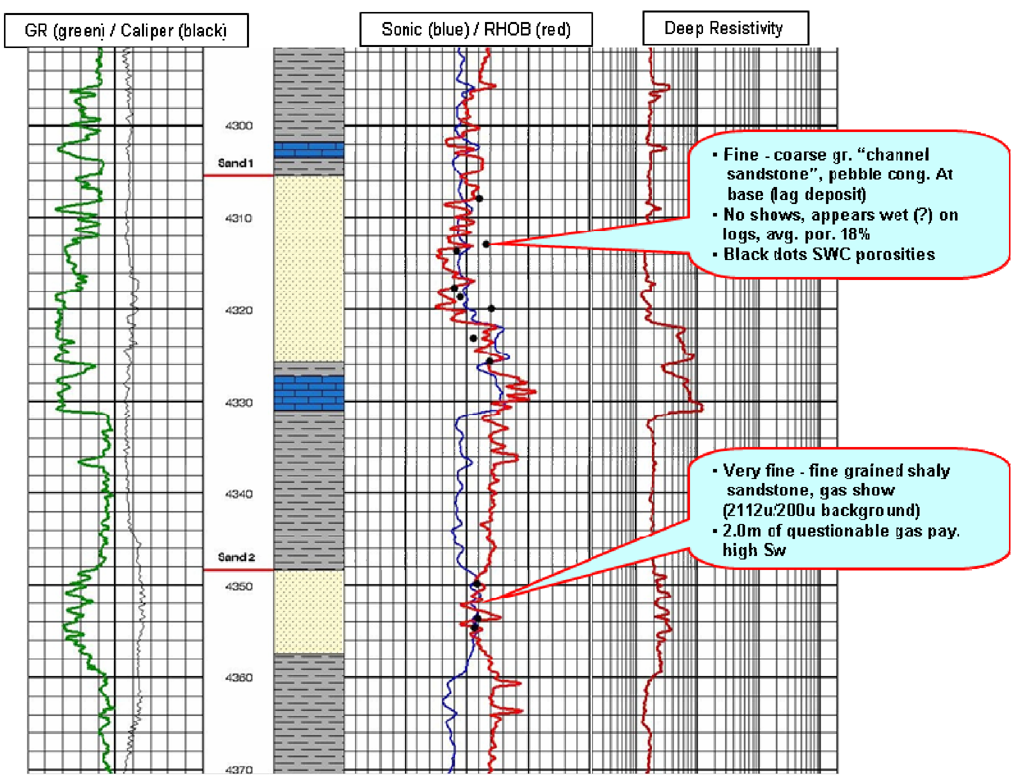


Figure 102. Newburn H-23: Well logs from Sands 1 and 2 (Early Albian).

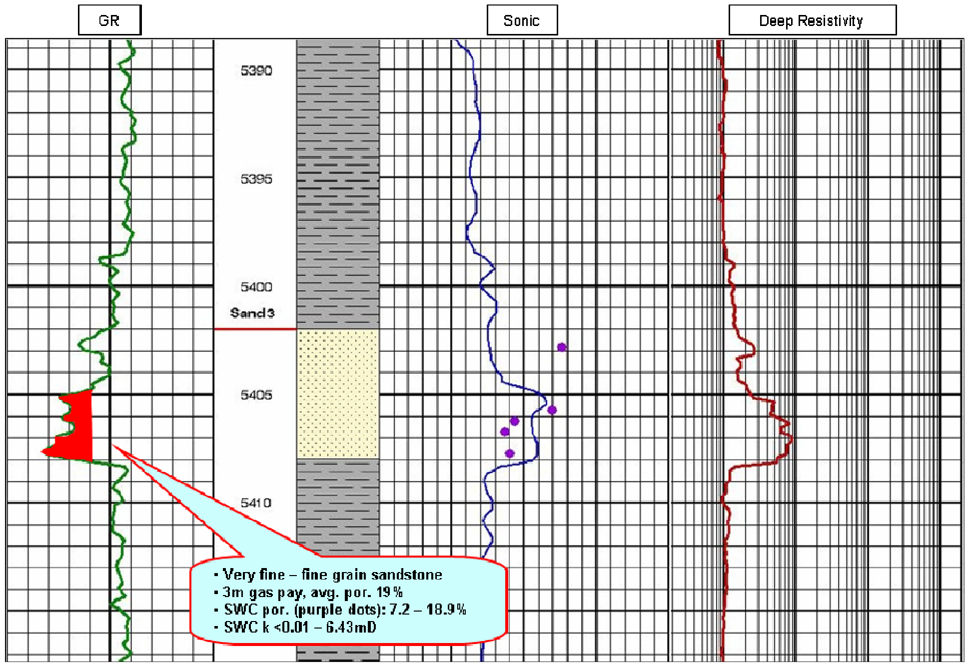


Figure 103. Newburn H-23: Well logs from Sand 3 (Mid Hauterivian).

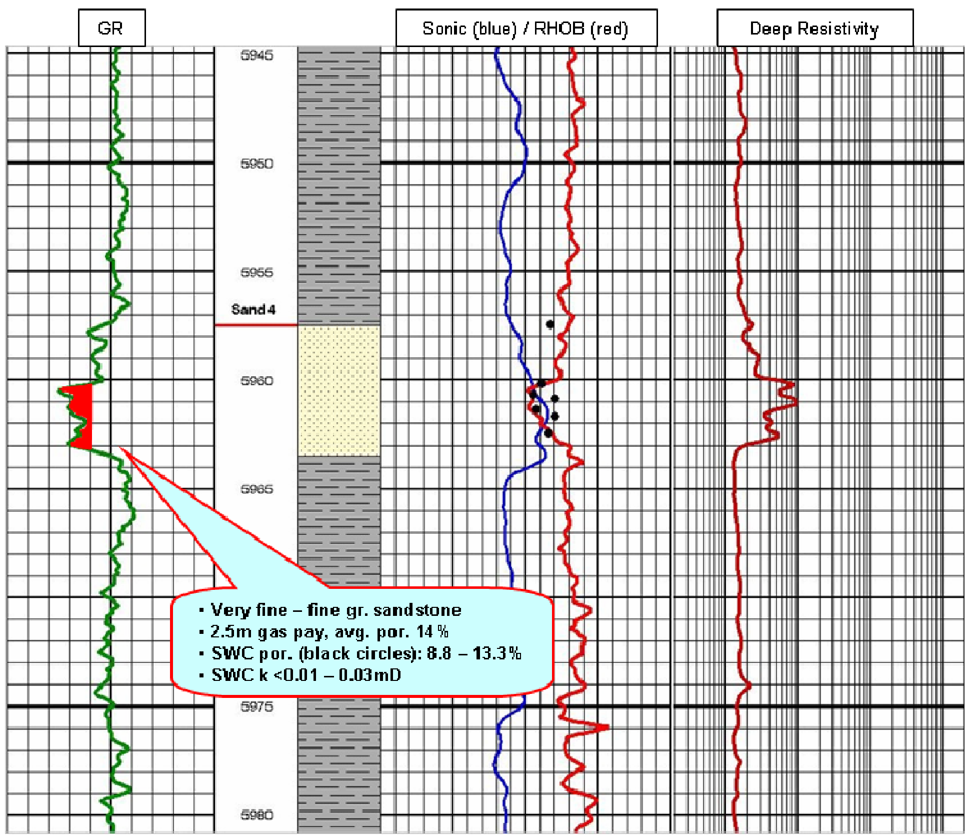


Figure 104. Newburn H-23: Well logs from Sand 4 (mid Hauterivian).

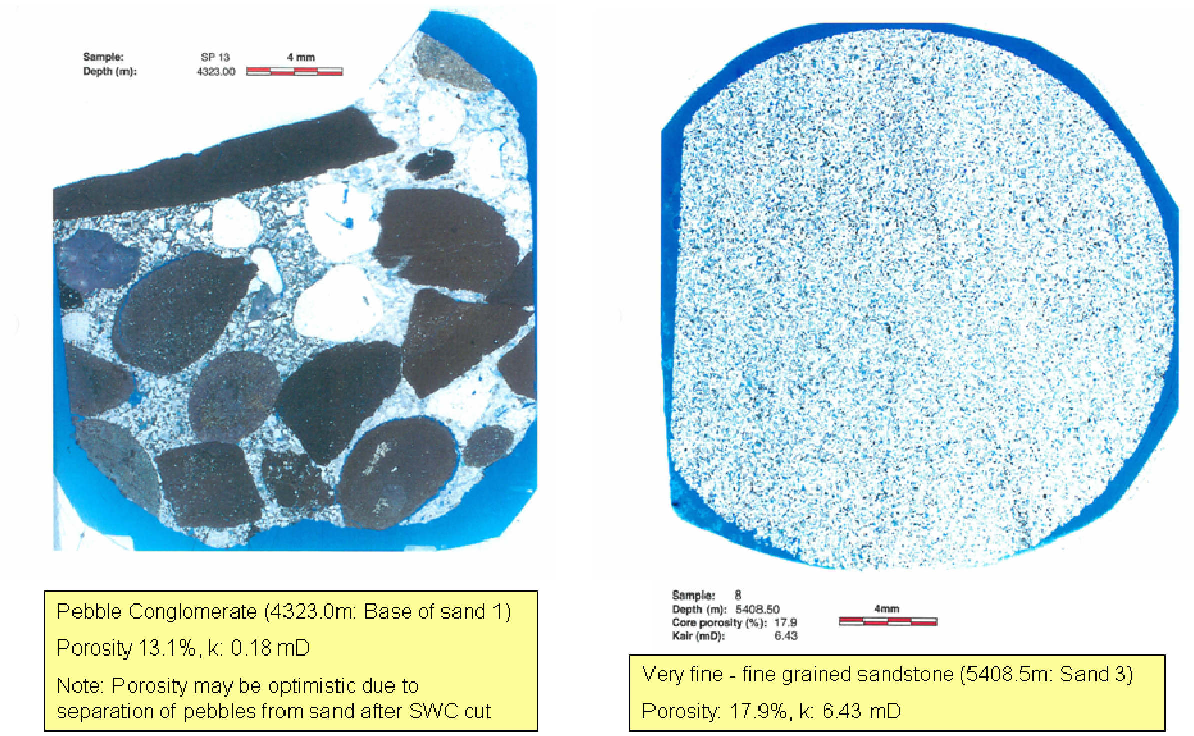


Figure 105. Newburn H-23: Photos of sidewall core thin sections.

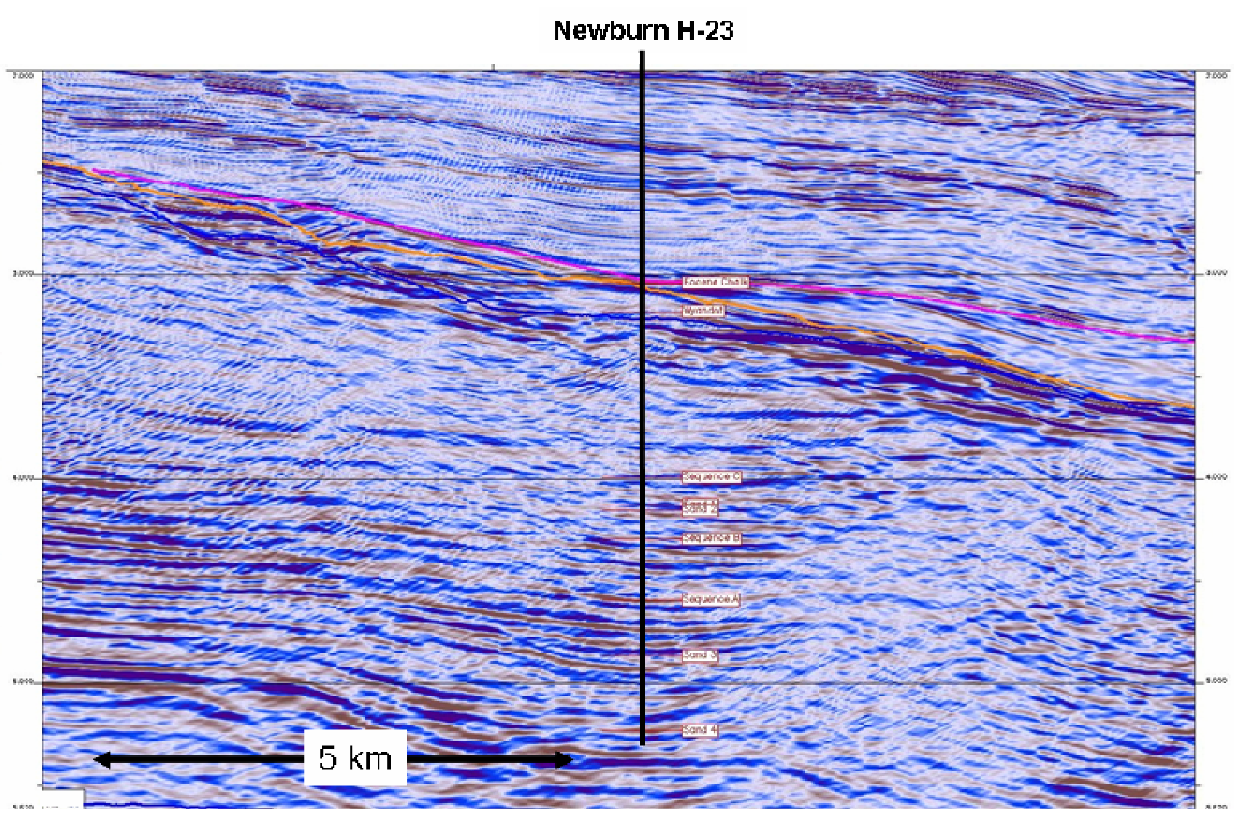


Figure 106. Seismic dip line (2-D) through Newburn H-23. Data courtesy of TGS-NOPEC.

Seismic Interpretation:

Figure 62 places Newburn into its regional context with the Evangeline and Weymouth wells. Figure 106 provides a detailed view of Newburn on the 2D data illustrating its poor quality at this location. The Board currently possesses only 2D data over Newburn.

The pre-drill seismic interpretation was apparently done on 3D data and likely based on lateral event correlation to adjacent shelf wells and seismic facies analysis. Isopach thicks would have been utilized to identify paleo-lows that could have concentrated turbidite sands. The data quality is relatively poor, even on the 3D data set, due in part to the deep channeling of the slope seafloor. There is no seismic evidence of up-dip canyon feeder systems that could deliver Cretaceous sands to this location. As a result, the geologic model correlating isopach thicks to the presence of sand appears to be tenuous, even though this was the best available concept at this time.

The synthetic in Figure 107 contains a segment the 2D TGS data, and reveals a poor correlation between the synthetic and the 2D seismic. The seismic data has more reflections, noise and interference than the synthetic. As described for the Shubenacadie well, many of the seismic reflections may result from varying calcite content of the shales and from siltstones and sandstones present in the deeper portion of the well.

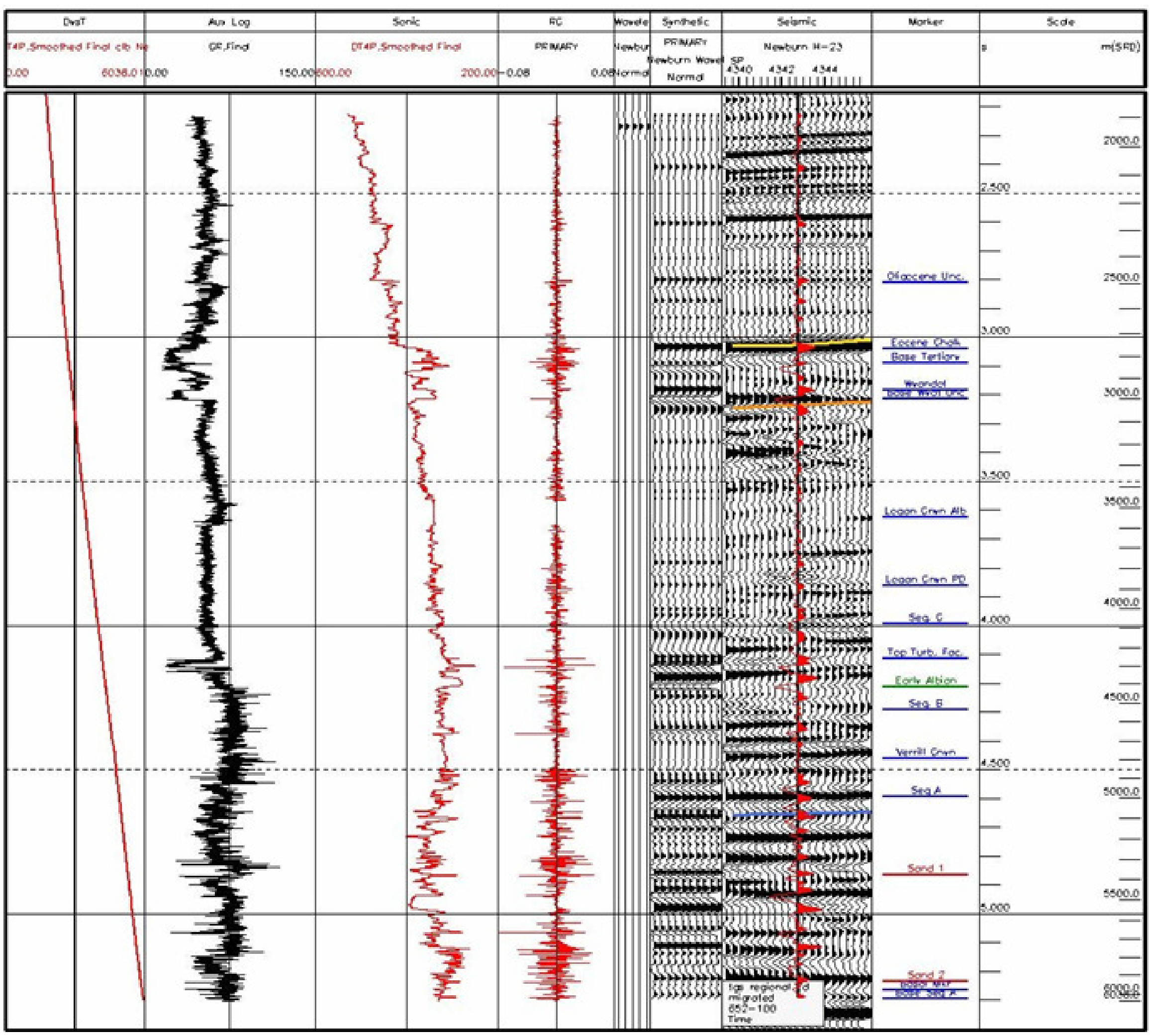


Figure 107. Newburn H-23: Synthetic seismic.

Biostratigraphy

Biostratigraphy (Robertson Research, 2004; Biostratigraphic Associates, 2002) indicates that Jurassic age sediments were not reached, and there exist a number of significant hiatuses, some of which represent major unconformities (Enclosures D, E). Within the Tertiary, Early-Miocene and Late Eocene submarine erosional events are regional in scope and correlative to adjacent wells. The Early Eocene unconformity is most pronounced and cuts down into latest Campanian sediments. A thin interval of (Wyandot) chalks and marls unconformably overly an equally large Middle to Late Campanian erosional event that removed Dawson Canyon and Petrel member strata. Remnant Mid-Turonian lower Dawson Canyon shales and siltstones in turn rest unconformably upon latest Albian upper Logan Canyon sediments. A significant Early Albian unconformity is present in the well and is much larger than the equivalent seen in the Annapolis and Crimson wells. The Balvenie did not reach this section. This event removed the basal part of the Cree and Naskapi members, and the top part of the Upper Missisauga formation down to the Early Barremian. The remaining ~1600 m of the Missisauga formation extends down to the middle of the Lower member of possible Valanginian age.

Paleoenvironment

The unconformities described above are important for seismic stratigraphic interpretations defining periods of erosion correlative to turbidite flows. However, paleoenvironmental interpretation of the Newburn succession indicates that the entire sampled Cretaceous (Middle Turonian to latest Valanginian) sequence was deposited in an outer shelf environment. Therefore, any potential turbidite reservoir sands would potentially be located distally from this location.

Geochemistry

A geochemical analysis of the H-23 well was completed for Chevron by Global Geoenergy Research (2002b). The approximately 1000m of Tertiary sediments in the well are immature. Below the successive Campanian, Eocene and Oligocene-Miocene unconformities, remnant late Cretaceous Logan Canyon formation strata are interpreted as moderately immature. The underlying Cree member is marginally mature. The Late Aptian to Early Barremian Naskapi shale member and top Missisauga formation are eroded, therefore the upper portion of the remaining Upper Missisauga sediments are still only marginally mature. The remaining upper and lower Missisauga sequence is in a mature to late mature state and well within the phase of maximum oil generation. Most sediments are considered gas- and condensate-prone being dominated by Type IIB-III kerogens, though a number of samples revealed the presence of Type II source rocks that are more oil-prone.

Total Organic Carbon (TOC) determinations for Newburn samples were conducted by PetroCanada (2002). The results revealed that the Middle Miocene has high TOCs ranging from 1.3 to 5.1% (avg. 2.6) and capable of generating liquid hydrocarbons, though it is immature (Table 9). The Late Eocene to Late Albian (Upper Logan Canyon) section is quite lean with an average TOC of only 0.7%. The Late to Middle Albian Logan Canyon (top Cree member) is richer with 1.4% average TOC, increasing to 2.6% in the remaining Cree section. Remaining deeper Missisauga sediments have lower average TOCs ranging from 1.2% (Barremian-Hauterivian). 0.7% (Hauterivian) to 1.4% (Middle Hauterivian-Valanginian).

Depth (m)	Formation	Age	Vitrinite Reflection (% Ro)	Kerogen Type	Maturity for oil generation
980	Sea Floor	Recent	n/a	n/a	n/a
1920 - 2720	Banquereau	L. Miocene (Tortonian) – M. Eocene (Lutetian)	0.23 – 0.31	II-III	immature
2920 - 3920	Dawson Canyon to Logan Canyon (Cree Mbr.)	L. Cret. (M. Turonian) to E. Cret. (M. Albian)	0.31 – 0.44	II, IIB-III	moderately immature
4120 - 4720	Logan Canyon (Cree Mbr.) to U. Missisauga	E. Cretaceous (E. Albian to L. Hauterivian)	0.50 – 0.57	II, IIB-III	marginally mature to mature
5120 - 6070	Upper to Lower Missisauga	E. Cretaceous (L.-M. Hauterivian)	0.67 – 0.92	II, IIB-III	mature to late mature

Table 9. Thermal maturation levels and kerogen types for the Newburn H-23 well (Global Geoenergy Research, 2002b). Ro values are ranges for the respective interval.

Exploration Implications

The Newburn prospect was viewed as a structured inverted low created as a result of adjacent salt mobility and listric faulting. A major component of the play concept was thus the ability to deconstruct or restore the present-day structural high into a syndepositional topographic low available for ponding of deep water sands. The prediction of potential reservoir sands required adjacent subsurface calibration points, however, none existed prior to drilling which compromised the model's integrity. Nevertheless, most sands encountered in the Newburn well were gas-charged, therefore proving that a working petroleum system exists. The pebble conglomerate, while minor, could be viewed as evidence of a possible feeder channel "lag" system within an overall canyon/fan complex.

Newburn lies within the Central Upper Slope area of the Board's 2002 assessment. This area was defined on 2D seismic data as the zone at the shelf break where imaging of the subsurface was poor and stratigraphic correlations from the shelf to the slope were tenuous. Some seismic lines show clear evidence of salt along this zone and in amongst major listric faults. Although there are limitations, modern 3D seismic is considered a superior tool in this incised slope setting to the 2D and allows operators to explore more effectively.

5.6.3 Well Operations

In drilling the Newburn H-23 well, significant operational problems/delays began in the 12 ¼"/311mm hole. The section TD was called approximately 500m shallower than planned due to increasing pore pressures (Figure 110). For the next hole section (8.5"/216mm), Chevron planned to drill to final TD. However, the well took a gas kick at 5405m MD (Sand 3) which required 6.3 days to control/circulate out. This resulted in the setting of an "extra" (i.e. unplanned) 7.75"/197mm liner. Another 3.8 days were also lost in the 216mm hole section cleaning out the hole for logging. Miscellaneous equipment failures in the final hole section (6.5"/165mm) resulted in another 3.7 days of delays.

The well was drilled and abandoned 10 days earlier than planned (93 versus 103) (Figure 108). It was completed early because drilling rates were faster than anticipated and the well TD was called 330m higher than planned because tops came in about 200m higher based on the earlier VSP (Figure 107).

5.6.4 Risk and Assessment

The Board's play adequacy for the Central Upper Slope was 64% and the prospect adequacy for that area was 25% for an overall chance of the prospect being successful of 16%. Proximity to the Sable delta and sands available for redeposition was judged to be favourable by the Board and the play adequacy was given an overall value of 64%, the highest of all 12 play areas:

- Source 100%
- Reservoir 80
- Trap 80
- Play Adequacy 64%
- Prospect Adequacy 25%
- Overall Chance 16% or 1: 6

Based on the well results, the play level reservoir adequacy, prospect level net pay and drilling success ratio factors have been downgraded (see Section 7.2).

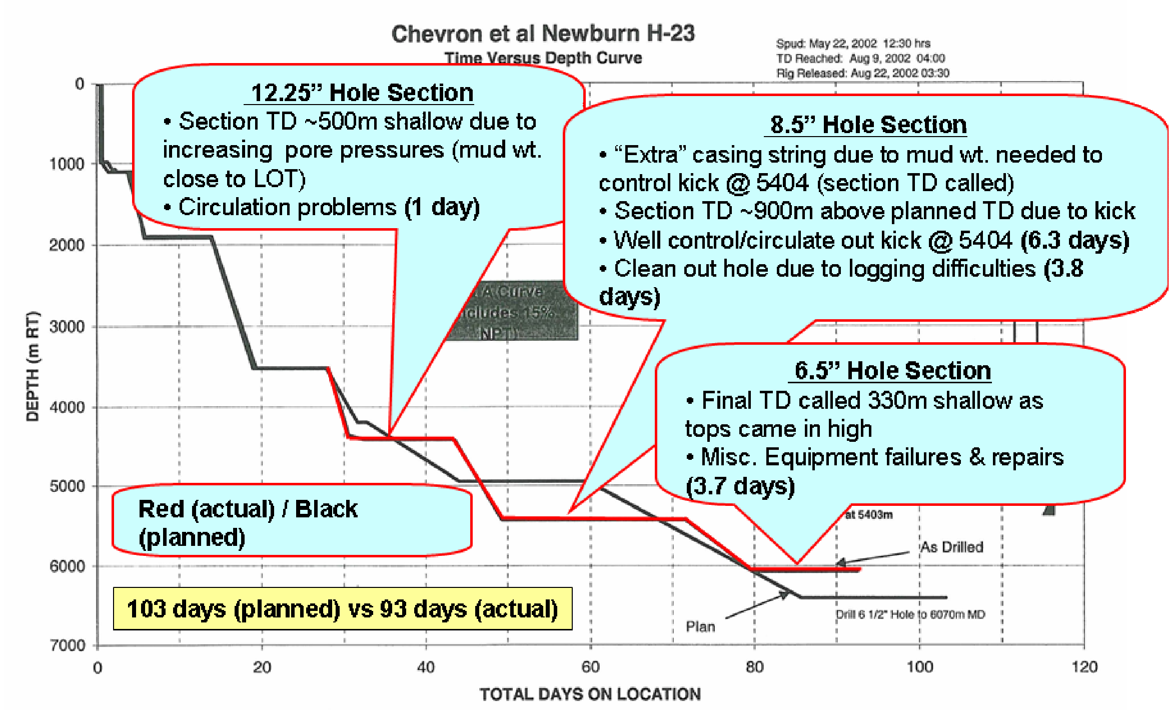


Figure 108. Drilling curve for Newburn H-23 (AFE and actual).

5.7 EnCana Torbrook C-15 (2002-03)

Almost 20 years after the Shubenacadie and Shelburne wells were drilled, a new operator returned to the western slope to test the Tertiary fan play (Enclosure A). EnCana spudded the Torbrook C-15 well in 1675m of water on November 16, 2002 using the newly built Eirik Raude semisubmersible with the well later abandoned on January 14, 2003.

5.7.1 Objectives and Concepts

The stratigraphic position of the target zones is shown in Figure 109. The primary target, seen on 2D seismic, was an interpreted Miocene-aged turbidite channel/fan system. The fan was interpreted to have been fed from sediments on the shelf via a canyon and deposited in a paleotopographic low. The secondary target was interpreted as an older Miocene fan complex (Figure 110) (EnCana, 2003). Two of the canyon feeder systems were identified at the Mohican I-100 and Moheida P-15 well locations and mapped over the Torbrook lease block. These systems were correlative with the Late Paleogene (Middle Oligocene) relative sea level fall, hence seismic sequence stratigraphy was an important tool.

The interpreted channel/fan system was mapped from seismic amplitude anomalies and illuminated a fan-shaped morphology (Figure 111). The details of the feature show internal bedding on the landward (up-dip) side and compressional toe thrusts with an overriding contact on the seaward side (Figure 112) The targeted section was the top of the internally bedded, EnCana-defined Tertiary 34 zone (T34) shown on a pre-drill lithology strip log (Figure 113). Reservoir prediction and hydrocarbon content were apparently based on seismic attribute analyses such as AVO, Vp/Vs ratios, LMR, forward modeling and interval velocities.

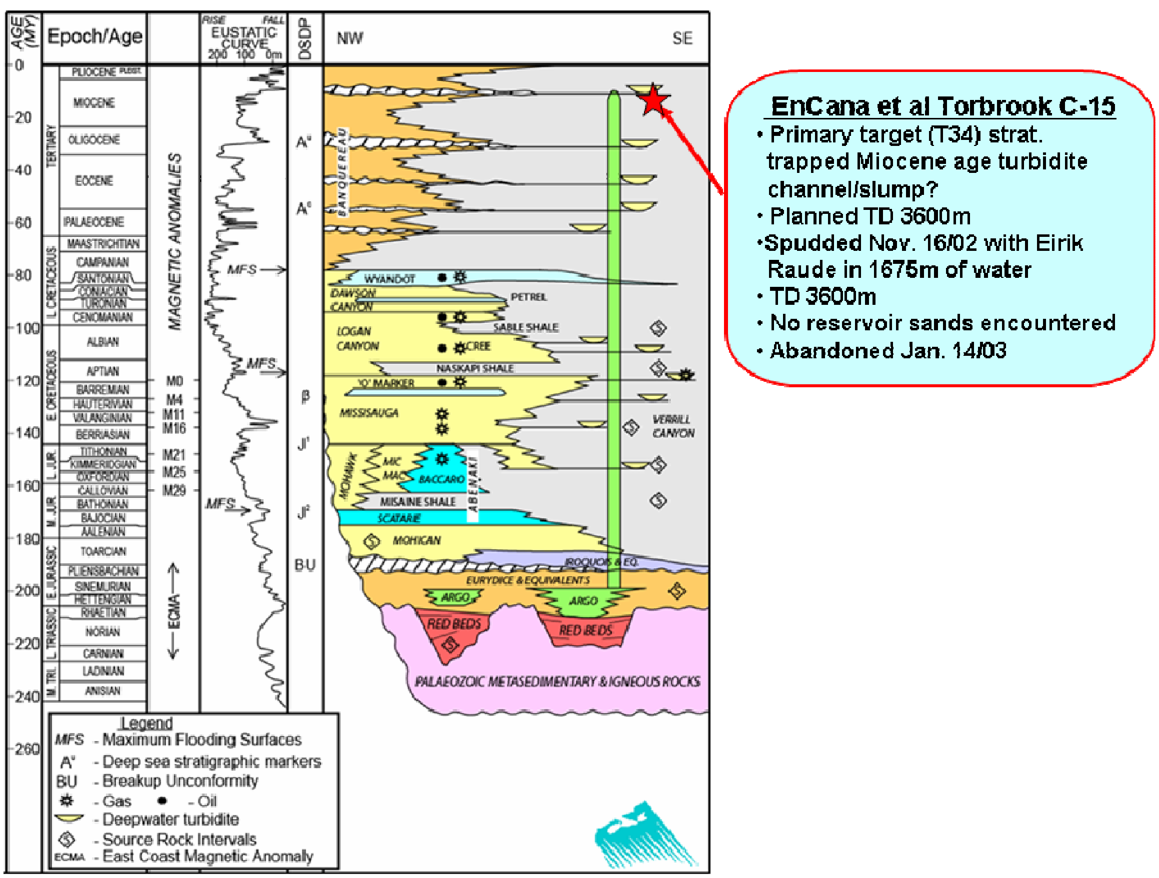


Figure 109. Stratigraphic chart showing target interval for Torbrook C-15.

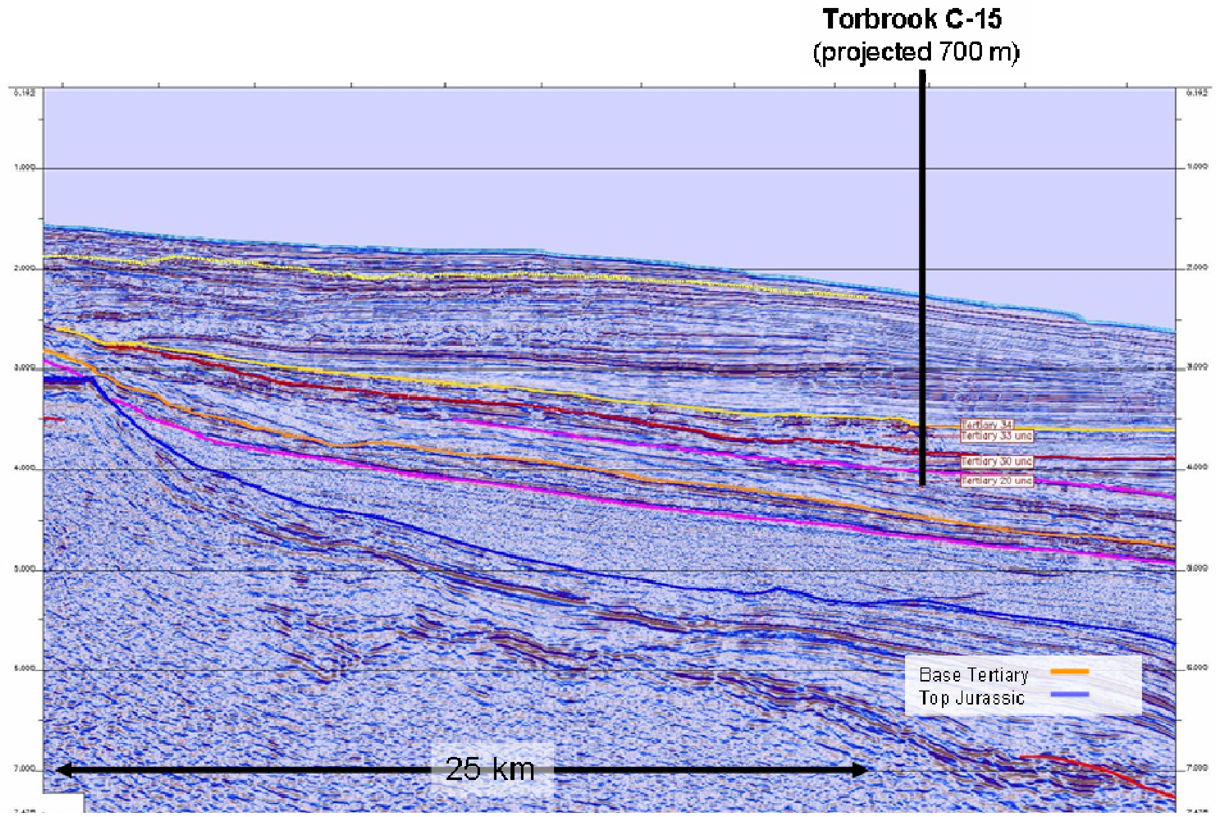


Figure 110. Seismic dip line (2-D) near Torbrook C-15. Data courtesy of TGS-NOPEC.

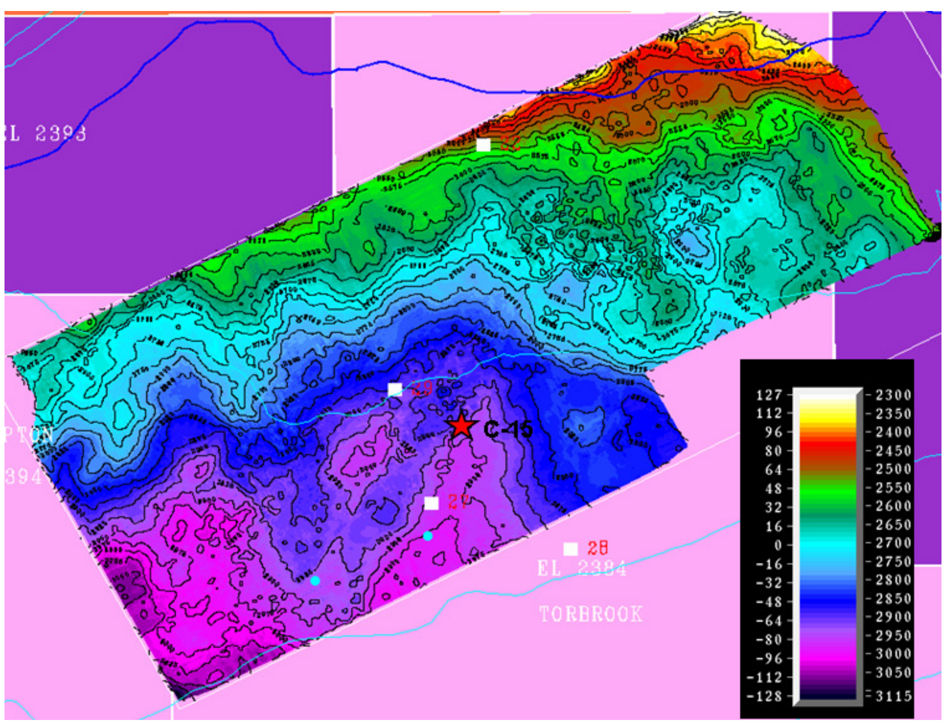


Figure 111. Top Tertiary_34 structure map. The red star shows the location for Torbrook C-25 (from Torbrook ADW, used with permission).

There are numerous Tertiary age submarine fan systems around the circum-Atlantic region with prolific oil and gas production. Potential analogues for the Torbrook feature exist in the GOM, West Africa and recently Mauritania of which much has been published. A review of the available seismic and comparison with analogues suggest two possible depositional models for Torbrook: in-place deposition behind an earlier slump, or, a post-depositional slump. Little information to support either of these models could be gleaned from surrounding wells. Indeed, the presumed fan targets in both the older Shelburne G-29 and Shubenacadie H-100 wells are now interpreted as erosional remnants (see Sections 5.1 and 5.3 respectively).

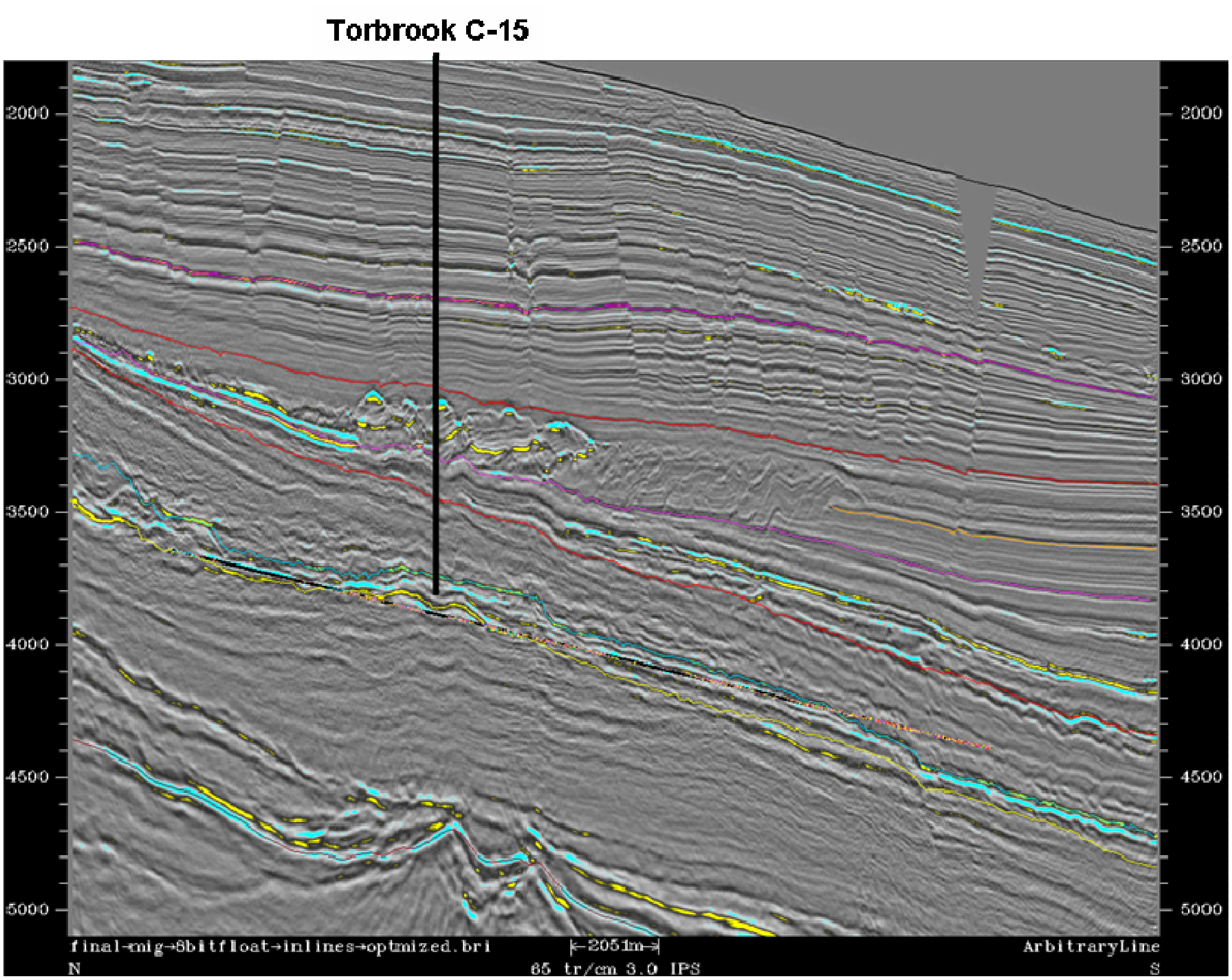


Figure 112. Seismic dip line (3-D) through Torbrook C-15 (from Torbrook ADW, used with permission).

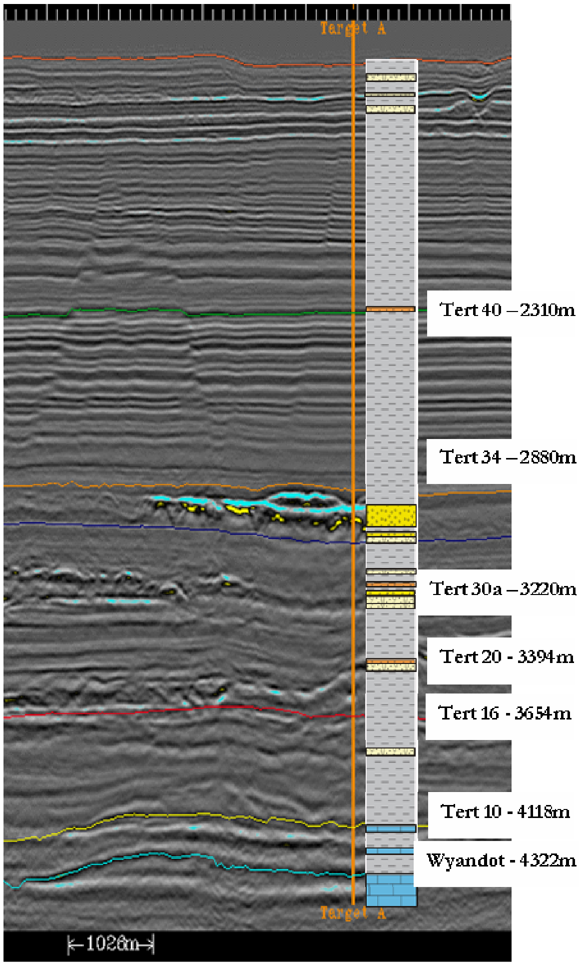


Figure 113. Torbrook C-15 pre-spud stratigraphic column. Primary target is the Tert34 (Miocene) turbidite/slump (Torbrook ADW, used with permission).

5.7.2 Results

Drilling

The base-case TD for the well was 3575m TVD, approximately 100m below the prognosed depth of the Tertiary 20 (T20) sand (Enclosure B) (EnCana 2003). Due to the lack of reservoir, drilling was terminated at 3600m TVD, approximately 160m below the top of the T20. Biostratigraphic data is not available but it is estimated that the well reached total depth in Miocene age sediments.

No hydrocarbon bearing reservoir quality sands were encountered in the well. The T34 primary target was penetrated at 2855m MD and consisted of poorly consolidated siltstone and shale/claystone which generated a minor mud-gas response of 50-80tgu peak/25u (Figure 114). This unit has no reservoir development. However, the strong amplitude response seen on seismic can be readily explained by the marked decrease in velocity across the zone as shown in the sonic response in Figure 118.

Secondary targets were the T33 and T20 horizons (Figure 115). The T33 was encountered at 2958m MD and consisted of thin, tight, siltstone with no shows. The T30 (3241m MD) was approximately 15m thick and consisted of non-reservoir siltstone and shale. It generated a weak mud-gas show of 86tgu/49u, but appears wet on logs. The T20 (3456m MD) zone is approximately 30m thick and lithologically is very similar to the T30. No shows were noted in the T20 and the zone appears wet on logs.

Twenty-six rotary sidewall cores (SWCs) were cut in the well. All were described as either silt or shale/claystone with the exception of the plug cut at 3479.5m (T20). The plug consisted of very fine-grained sandstone with clay matrix and very poor intergranular porosity (Figure 116). This SWC was cut at the base of the T20 and indicates that minor sandstone is present within the interval, but it has no reservoir potential.

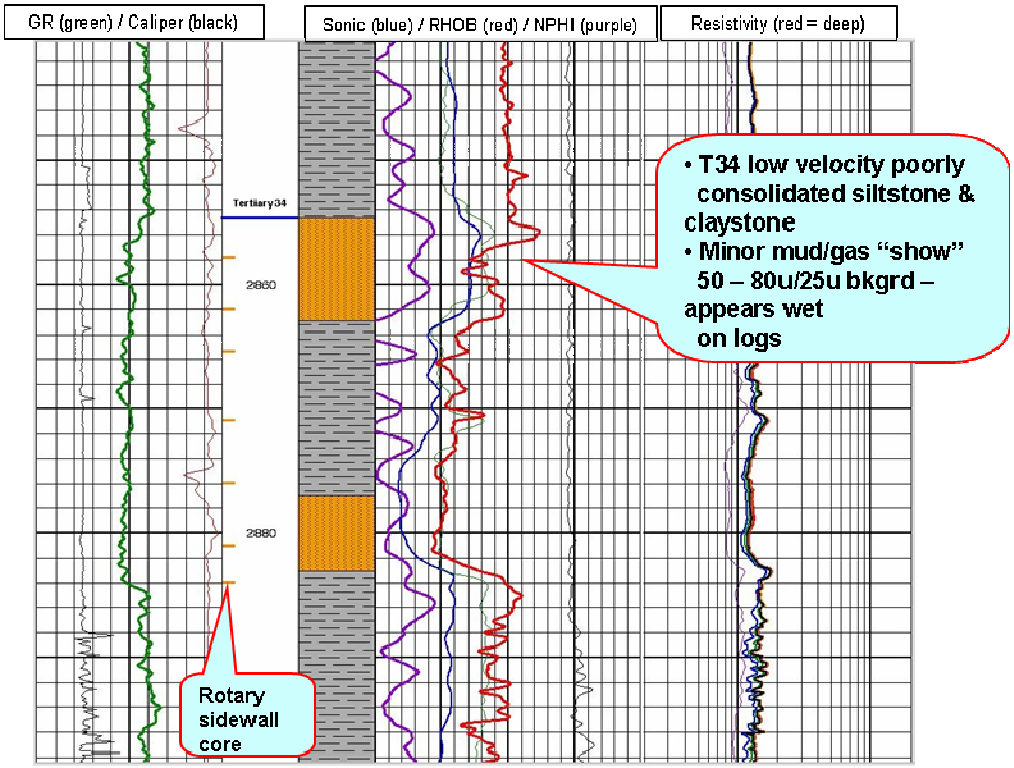


Figure 114. Torbrook C-15: Well logs from the Tertiary 34 zone (Miocene?).

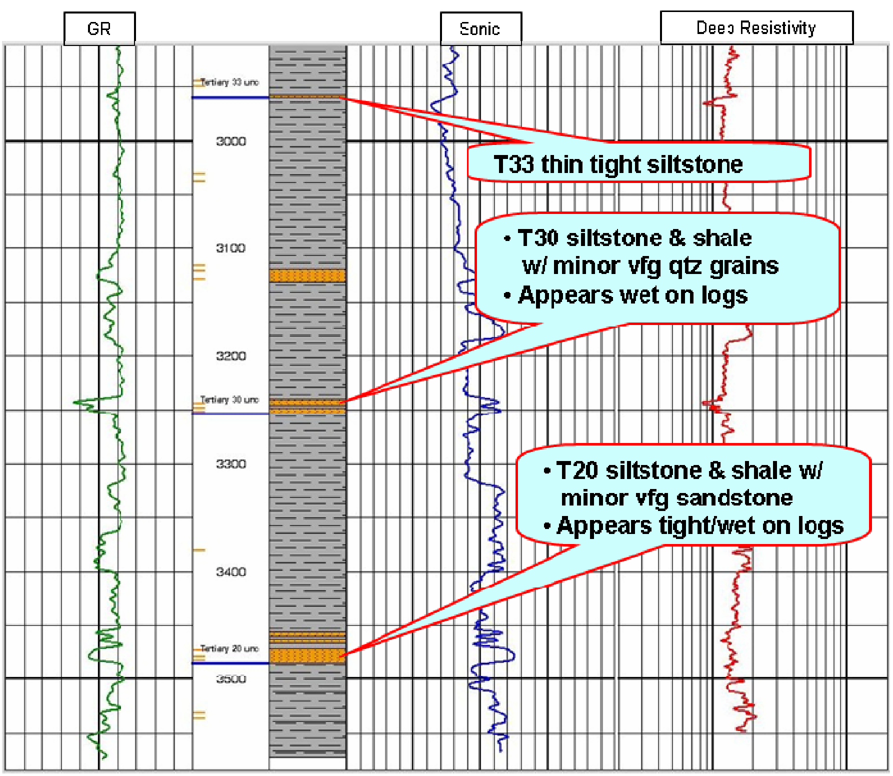


Figure 115. Torbrook C-15: Well logs from Tertiary 33 to TD, below Tertiary 20 (E. Miocene – L. Eocene?).

Seismic Interpretation

The Torbrook anomaly is about 25km seaward of the Jurassic carbonate bank margin. Figure 112 details the internal structuring of the anomaly on EnCana's 3D data. Down-dip of the well location, the internal configuration of the target interval indicates massive slump features, including toe thrusts present on a through-going failure surface. A schematic illustrates the classical shelf margin slump or mass wasting feature (Figure 117). The initial post-drill observation supports the interpretation that the anomaly was a classic slump feature with no related submarine fan deposition.

The well synthetic seismogram displays the overwhelming amplitude response of the low velocity T34 "muck" (i.e. poorly consolidated siltstone and claystone). Otherwise, it shows a fairly good correlation in the Tertiary section (Figure 120).

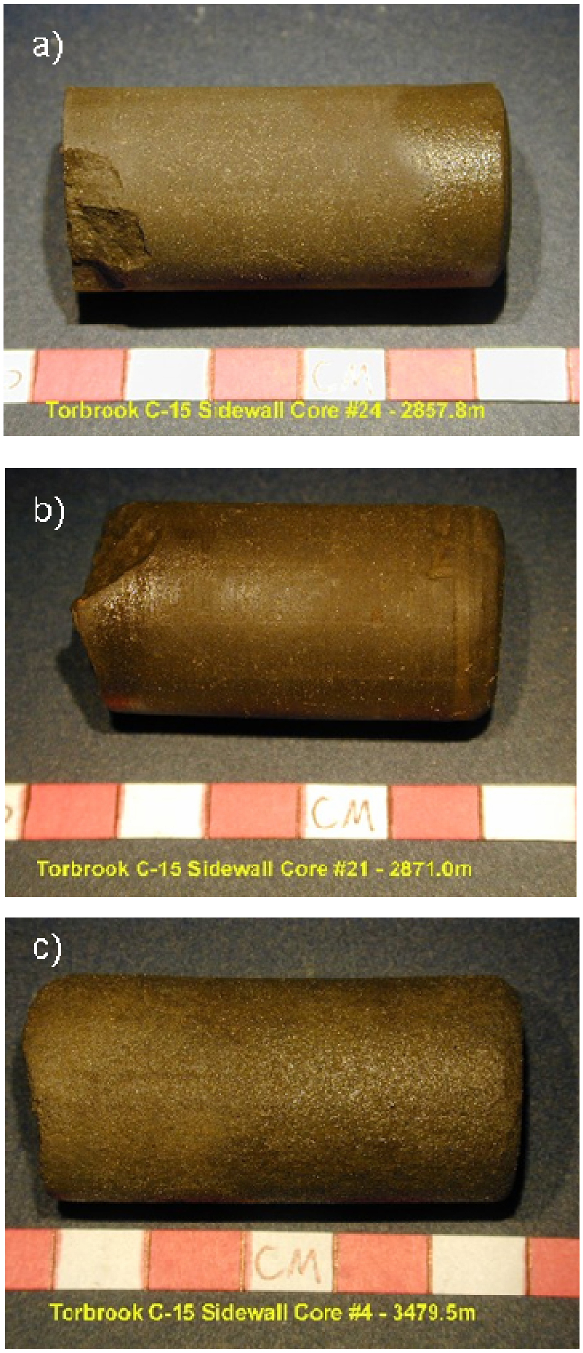


Figure 116. Sidewall core photos from Torbrook C-15. a) Siltstone from Tertiary 34 zone. b) Shale from Tertiary 34 zone. c) Very fine-grained sandstone from Tertiary 20.

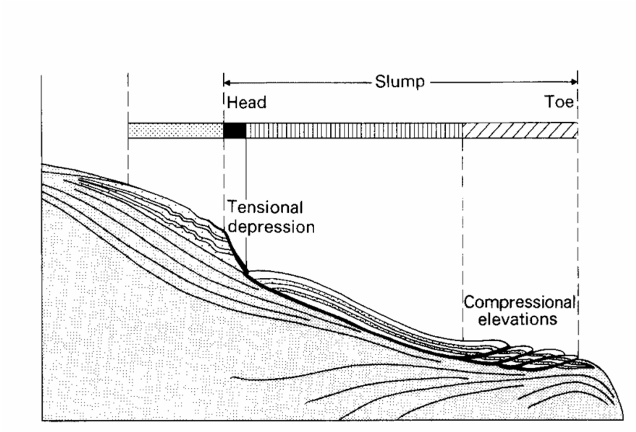


Figure 117. Schematic of a slump feature on the continental slope (Woodcock, 1976).

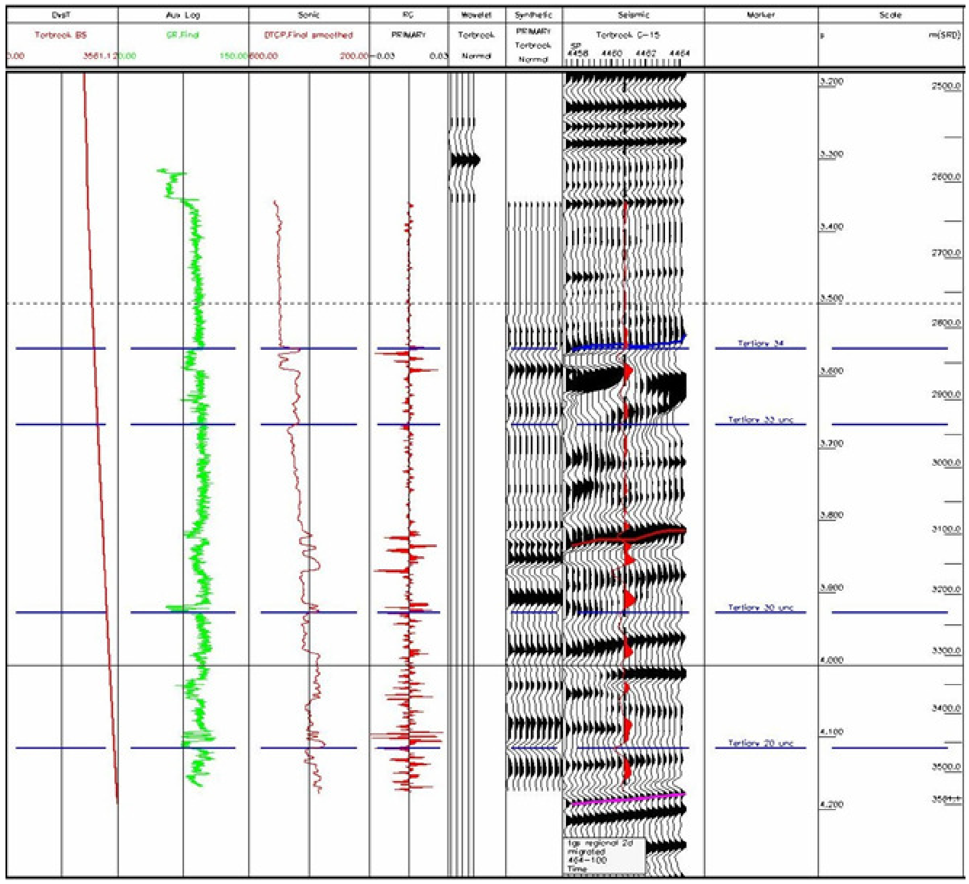


Figure 118. Torbrook C-15: Synthetic Seismic.

Biostratigraphy, Paleoenvironment and Geochemistry

Biostratigraphic and geochemical information on this well from the operator or outside sources was not available to the authors during the preparation of this report.

Exploration Implications

Based on well results, the interpreted submarine fan is not a redepositional feature but rather a slump of fine-grained slope material. It is most likely the chaotic internal nature of the slumped mass gave rise to signal attributes that while interpreted as a fan bears no relationship with potential reservoir facies. The lithofacies penetrated supports the slump interpretation. Therefore, the well did not test a submarine fan and is not a diagnostic test of the play.

Regional seismic interpretation indicates a relatively thin, starved Cretaceous age sedimentary succession for the western Scotian Slope when compared to the central slope region in front of the Sable Delta. Considering the globally known and frequent Tertiary highstand and lowstand events, it remains uncertain as to how the shelf depositional systems functioned along the Scotian Slope.

5.7.3 Well Operations

It was estimated that the well could be drilled in 49 days (Figure 119) (EnCana, 2003). This was the first well drilled by the Eirik Raude dynamically positioned drillship and there were approximately six extra days needed to load supplies/equipment on board and prepare the rig prior to spud. Other significant delays included 4.7 days waiting on weather and 13.2 days troubleshooting and repairing cables/conduits on the riser and BOP. The well was drilled and abandoned in 74 days, 25 days over budget.

5.7.4 Risk and Assessment

The Torbrook well is located in the Western Upper Slope play area where the dominant assessed play types were pre-Tertiary anticlinal features and tilted fault blocks. Whereas the Tertiary fan play was recognized as a valid concept, it was not assessed primarily due to the predicted immaturity of Tertiary source rocks and the need for longer distance hydrocarbon migration. Therefore, this well's results do not directly affect the numerical assessment, though it does affect the viability of the Tertiary fan play and the ability to detect them on seismic.

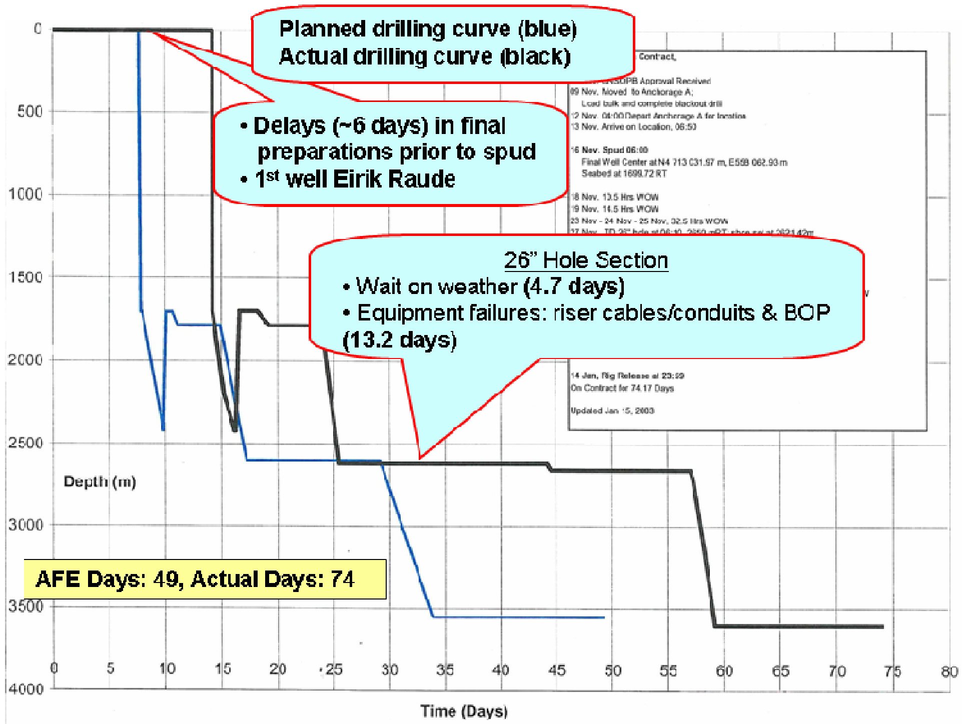


Figure 119. Drilling curve for Torbrook C-15 (AFE and actual).

5.8 Imperial Balvenie B-79 (2003)

Imperial's first venture into the deepwater was Balvenie B-79 which spudded on July 6, 2003 in 1803m of water using the Eirik Raude semi-submersible. The rig was released on September 6, 2003 and the well abandoned (Enclosure A).

5.8.1 Objectives and Concepts

The Balvenie well's objectives were Missisauga fm. equivalent turbidite sandstone reservoirs of Albian and Aptian age within the 4435-5625m interval. This interval was designated by the operator as the C32–C25 sequence (Figure 120) (Imperial Oil Resources Ventures Limited, 2003). Well TD was set at 5025m MD to evaluate the C32–C30 sequences, though could be deepened to 5625m MD to assess the C25 interval should promising results be encountered in the upper units.

Seismic interpretation suggested that the Balvenie structure was formed as a result of Early Cretaceous (Valanginian?) loading of pre-existing Argo formation salt diapiric structures that were initiated in the Middle Jurassic (Figure 121), (Imperial Oil Resources Ventures Limited, 2003). The allochthonous salt formed canopies and were progressively deflated by further sediment deposition and welded, likely near the end of the Early Cretaceous. This process would have created topographic lows prone to capture and accumulation of possible turbidite sands. Subsequent listric growth faulting in the Late Cretaceous (Cenomanian-Turonian?) formed an anticlinal feature with separate culminations. The southern end of the structure underwent a period of significant submarine erosion and was breached near the end of the Late Cretaceous.

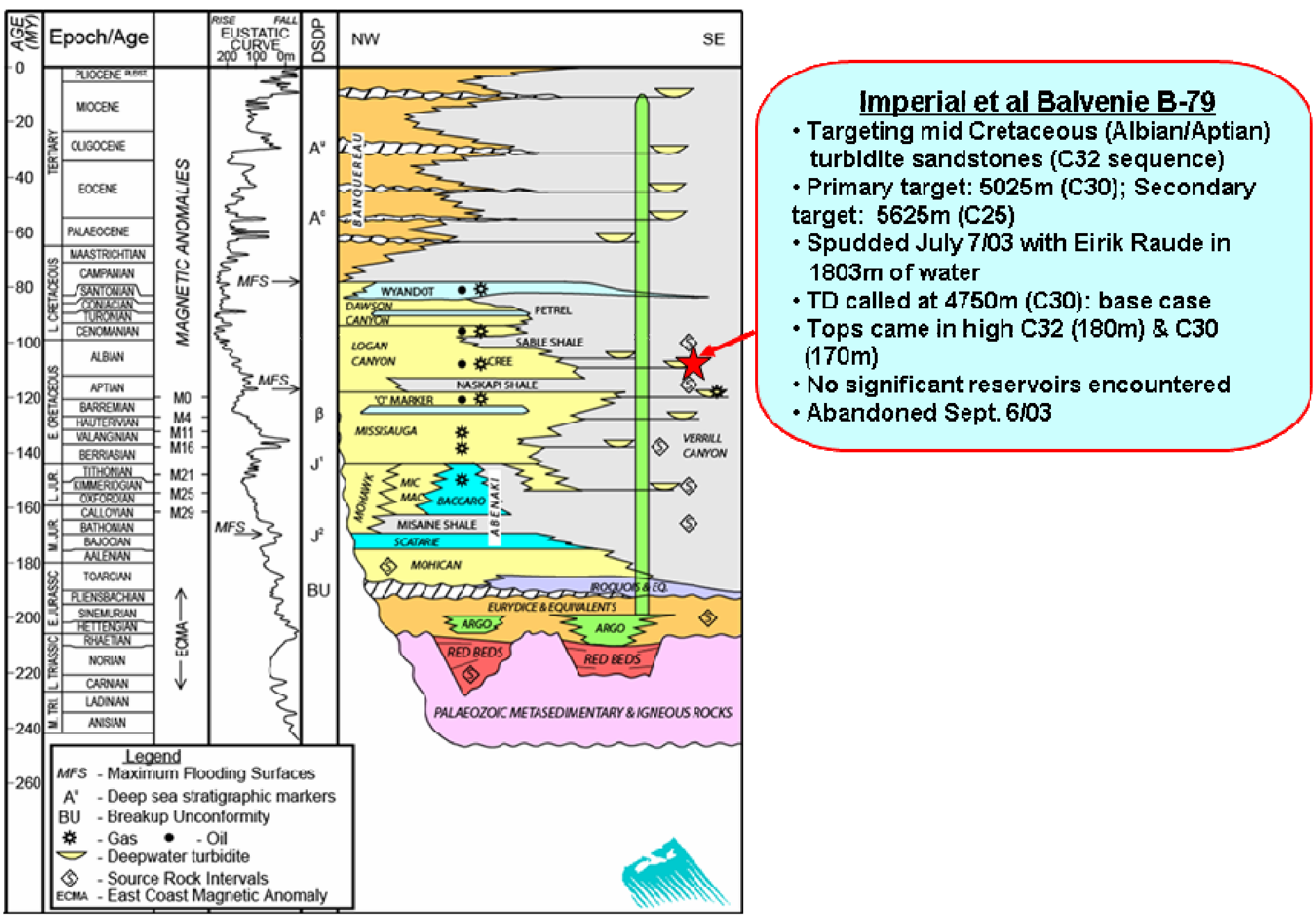


Figure 120. Stratigraphic chart showing target interval for Balvenie B-79.

The well location was based on 3D pre-stack time and pre-stack depth migrated seismic data (Figure 122) (Imperial Oil Resources Ventures Limited, 2003). Potential reservoir sand intervals were identified from regional 2D and prospect 3D seismic and well-based stratigraphic studies. The Annapolis G-24 and Newburn H-23 were the only deepwater control wells available. Four potential target objectives were identified ranging in age from Aptian to Cenomanian. The primary reservoir objective was the C32 (Albian) level with several amplitude anomalies exhibiting modest AVO response. A secondary zone at the C35 (Albian) level was partially eroded. The well location was optimized to test target reservoirs within the predicted best facies, in a structurally favourable position, and having amplitude and AVO anomalies (Imperial Oil Resources Ventures Limited, ibid).

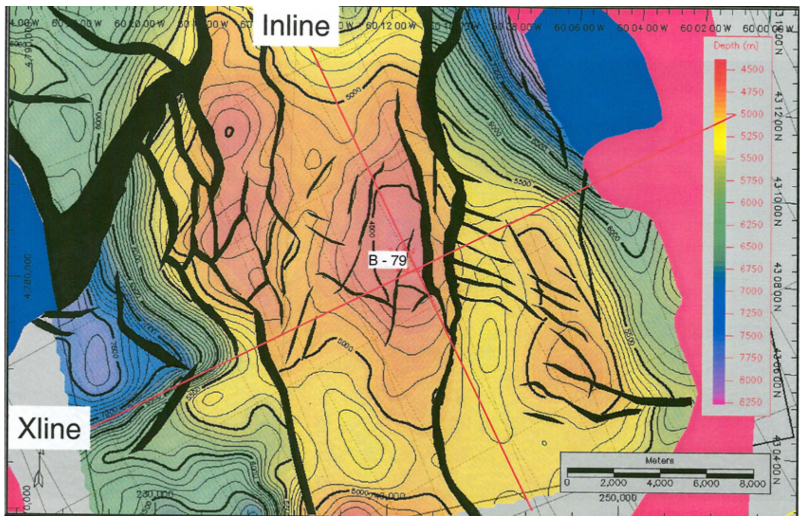


Figure 121. Top structure map for the C32 target zone at Balvenie B-79 (Balvenie ADW, used with permission).

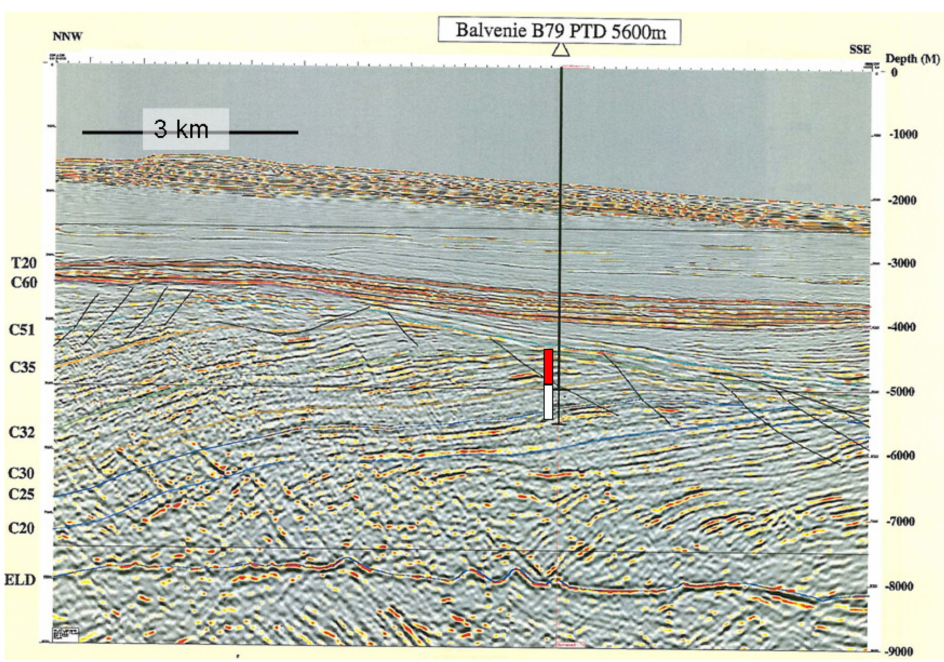


Figure 122. 3-D seismic dip section through Balvenie B-79 target. Primary target zone is highlighted by the red bar; secondary target by the white bar (Balvenie ADW, used with permission).

5.8.2 Results

Drilling

The Balvenie well was drilled to a TD of 4750m MD terminating in the early Albian C30 sequence (Enclosure B). The VSP data acquired at TD indicated that the C32 and C30 target sequences were 180m and 170m above the prognosed tops respectively. The well was not deepened to test the C25 interval due to the lack of reservoir development in the shallower C32-C30 sequence.

Two thin (~2m thick) poorly cemented, fine- to medium-grained sands of late Maastrichtian age were encountered between 3610–3640m MD (Figures 123, 124). The sands were washed out during drilling as shown by the caliper logs, but were nevertheless shown to be wet on logs. This was expected as there is no closure indicated at this depth.

The gamma ray log between 3160–3750m MD displays a pronounced fining-upwards trend. This interval consists of shale, with lesser limestone and marl. The fining-upward profile is caused by a reduction in the amount of finely disseminated calcareous material within the shales. The lithologies at the bottom of the interval range from highly calcareous shales to marls that gradually grade into "pure" shale at the top of the zone (Figure 123).

Within the C35–C32 base case target interval (4232–4680m MD), several thin, tight, gas-charged siltstones were encountered (Figure 124). These siltstones ranged from 1–8m thick and produced considerable mud-gas shows during drilling. The Balvenie B-79 Well History Report noted that the AVO anomalies targeted on the seismic in fact tie to the gas charged silts encountered in the C32 sequence (Figure 125).

Using indicators such as mud-weight increases in response to connection and trip gas, sonic and resistivity log trends, and cuttings descriptions, the top overpressure was estimated to occur at approximately 3500m TVD.

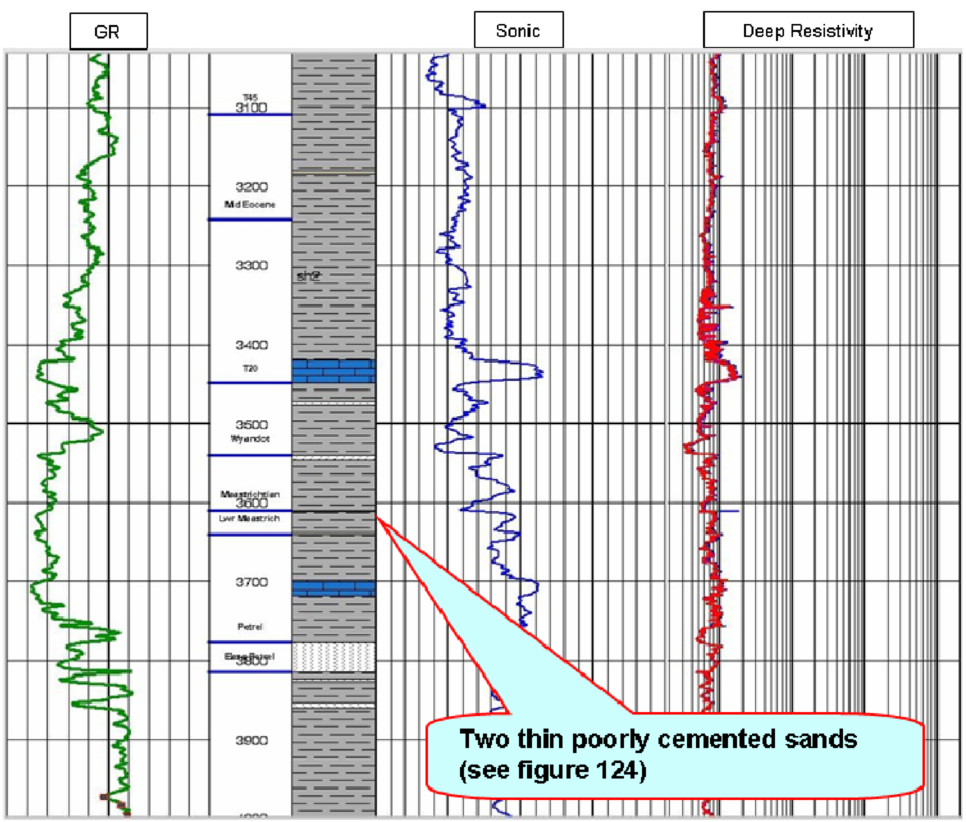


Figure 123. Balvenie B-79: Well logs from the Eocene – Cenomanian section (including Wyandot Formation).

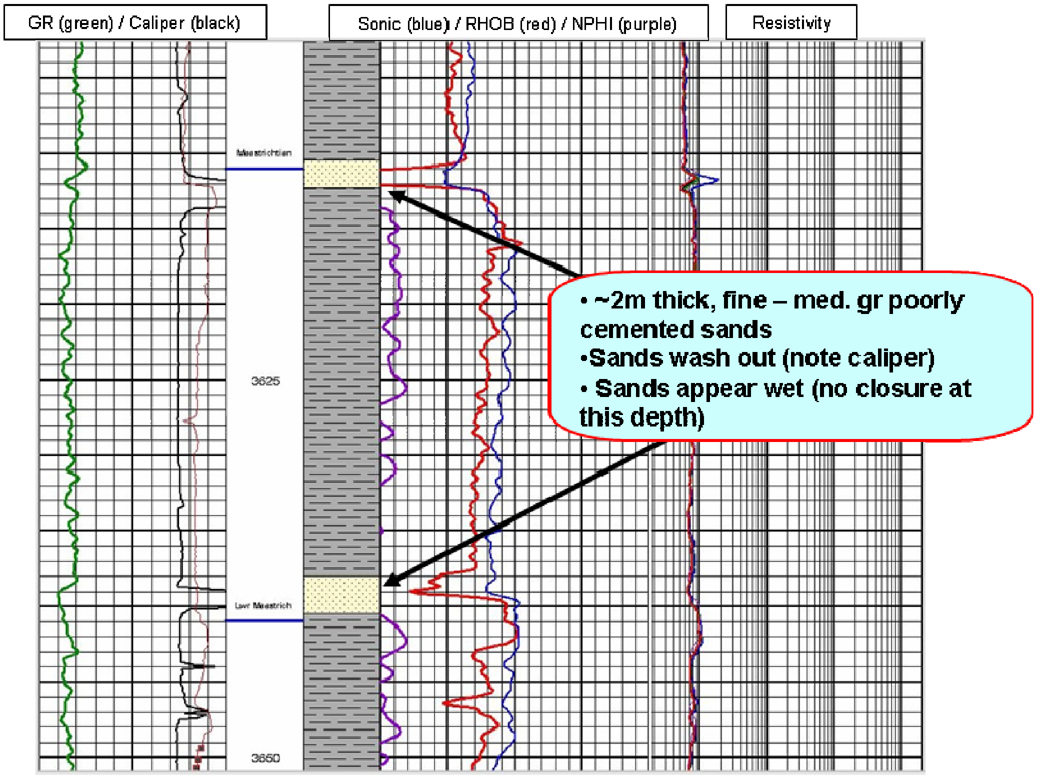


Figure 124. Balvenie B-79: Well logs from Late Maastrichtian sands.

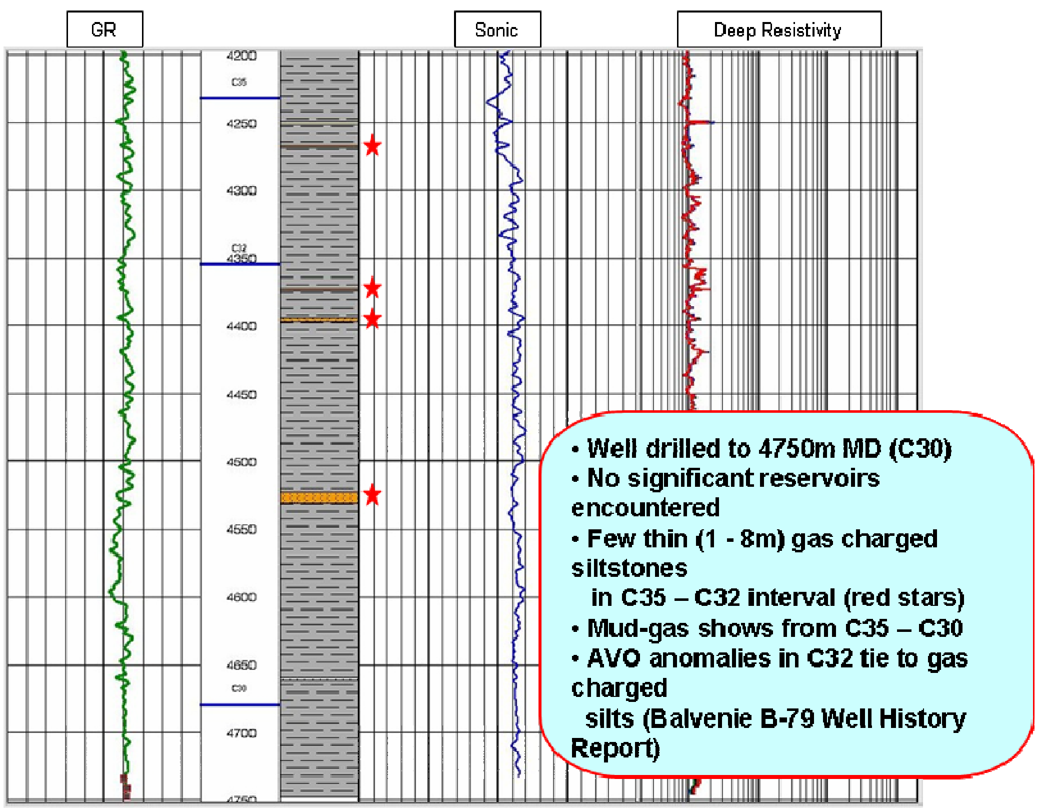


Figure 125. Balvenie B-79: Well logs from the primary target interval (Albian).

Seismic Interpretation

Figure 126 displays a northwest-southeast trending CGGVeritas 3D dip line through Balvenie. A salt feeder stalk and associated salt weld are evident near the base of the section. The structural reversal on the up-dip portion of the Balvenie structure is caused by salt collapse and movement along the salt weld/fault glide plane. The Balvenie pre-drill depth map (Figure 121) reveals numerous small faults present at the crest and flanks of the structure, though overlying thick shales would presumably provide effective top and lateral seals. Correlation of the well synthetic (Figure 127) to the 3D dataset is fairly good for the shallow the Eocene to Wyandot chalk interval and a deeper zone including the gas-charged silts.

There is a concern with the high degree of erosional truncation on the southeast flank of the structure (Figure 126). As a result, the well tested only 515m of prospective section and leaving over 1000m of untested Cretaceous strata preserved updip. The prospective section tested by the Balvenie well is illustrated in Figure 122 and highlighted in yellow. This 515m thick section appears to be thinning basinward and may not represent a depositional thick with a commensurate reduction in the probability of coarse siliciclastics being deposited in this setting. Thus, the Balvenie prospect, while currently displaying structural relief, may never have been a paleotopographic low. Modeling Balvenie’s evolution through time requires a comprehensive understanding of its depositional and tectonic history that the current dataset cannot yet provide, and so the existing model remains a high-risk non-unique solution.

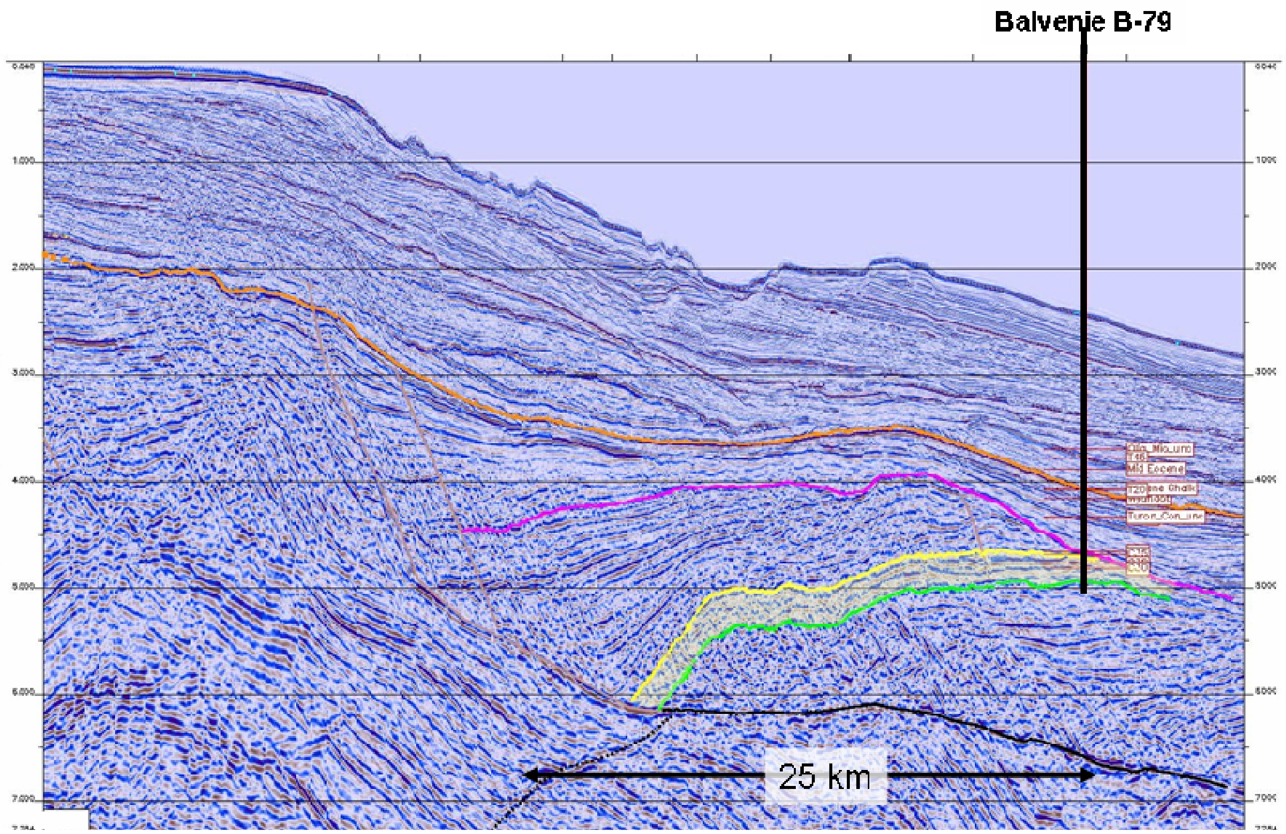


Figure 126. Seismic dip line (2-D) through Balvenie B-79. Target interval is highlighted in yellow. Data courtesy of TGS-NOPEC.

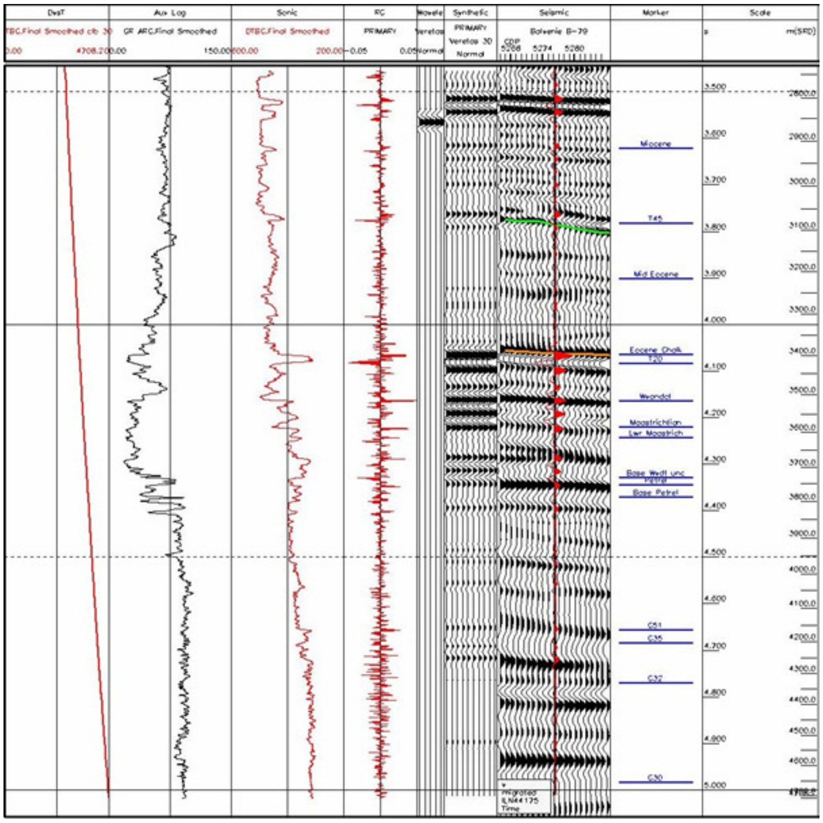


Figure 127. Balvenie B-79: Synthetic Seismic.

Biostratigraphy

A detailed biostratigraphic analysis of the Balvenie B-79 well completed for Imperial by Robertson Research (2003). The well penetrated a Tertiary section that contained a number of hiatuses and unconformities (Enclosures D, E). The most significant is a major Late Miocene unconformity which removed all sediments down to the Oligocene-Eocene boundary. The lower Middle Eocene is missing from an earlier (Bartonian?) event. The remaining Eocene and entire Paleocene section is essentially complete with some possible minor hiatuses. The underlying Late Cretaceous succession is complete down to the base of the chalk and shale Wyandot formation, and overlies the truncated Dawson Canyon formation. The early Santonian (?) erosional event removed the upper half of the Dawson Canyon mudstones and chalk-marl Petrel member with only the basal Early Turonian portion of the formation preserved. The mudstone dominated sedimentary sequence is continuous from the Early Turonian down to the earliest Albian Logan Canyon formation where the well bottomed in middle of the targeted Cree member.

Within the Tertiary, Early-Miocene and Late Eocene submarine erosional events are regional in scope and correlative to adjacent wells. The Early Eocene unconformity is most pronounced and cuts down into latest Campanian sediments. A thin section of Wyandot formation chalks and marls unconformably overly an equally major Middle to Late Campanian erosional event that removed Dawson Canyon and Petrel member strata. Remnant Middle Turonian lower Dawson Canyon shales and siltstones in turn rest unconformably upon latest Albian upper Logan Canyon sediments. A significant Early Albian unconformity is present in the well and much larger than the equivalent seen in the Annapolis and Crimson wells (the Balvenie well did not penetrate this section). This event removed the basal part of the Cree and Naskapi members, and the top part of the upper Missisauga formation down to the Early Barremian. The remaining ~1600m of the Missisauga formation extends down to the middle of the Lower member of possible earliest Valanginian age.

Paleoenvironment

The paleobathymetric profile of the Balvenie section reveals that most of the Tertiary age Banquereau formation strata were deposited in an upper slope setting. Outer shelf environments are interpreted for some parts of the Early Eocene and Early Pliocene. Deeper middle slope settings are recognized in Middle Eocene sediments. Late Cretaceous shale, chalk and marl sequences of the Wyandot and Dawson Canyon formations are reflective of outer shelf conditions. Mud-dominated sediments of the Logan Canyon target zone are all considered to have been laid down mostly on the shelf to outer shelf, though there is evidence of deposition on the top reaches of the upper slope at the top of the Albian.

Geochemistry

All sampling for geochemical analysis was within the top Early Cretaceous Logan Canyon formation (Cree member) except for a single point in the Tertiary (Table 10) (Global Geoenergy Research, 2004). Between the Tertiary and Early Cretaceous, there are two major unconformities (Early Eocene to Late Campanian, and Early Santonian to Early Turonian) resulting in significant time gaps. The sampled Tertiary section, and by inference the strata below the Eocene unconformity, is immature. The underlying Dawson Canyon and Wyandot formations shales and chalks/marls, though not sampled, are immature. The targeted Cree member of the Logan Canyon succession ranges from moderately immature in the upper portion to mature in the central part. Kerogen is dominated by Type III gas-prone organic matter, with modest levels of Type II gas- and oil-prone kerogen.

Depth (m)	Formation	Age	Vitrinite Reflection (% Ro)	Kerogen Type	Maturity for oil generation
1803	Sea Floor	Recent	n/a	n/a	n/a
2795	Banquereau	E. Pliocene (Zanclean)	0.28	III	immature
4215 - 4365	Logan Canyon (Cree Mbr.)	E. Cretaceous (M. – L. Albian)	0.40 – 0.44	(II)-III	moderately immature
4415 – 4545	Logan Canyon (Cree Mbr.)	E. Cretaceous (E. – M. Albian)	0.45 – 0.49	(II)-III	marginally mature
4635 - 4745	Logan Canyon (Cree Mbr.)	E. Cretaceous (E. Albian)	0.51 – 0.57	III	mature

Table 10. Thermal maturation levels and kerogen types for the Balvenie B-79 well (Global Geoenergy Research, 2004). Ro values are ranges for the respective interval.

Exploration Implications

In hindsight, the Balvenie well was incorrectly located near the eroded flank of a structural closure and thereby missing a thick Upper Cretaceous section. The single, narrowly focused target resulted in only 550m of prospective section being tested. Within that interval, only a few thin sands were encountered, and not the modeled gas-charged sands.

The Balvenie well results accentuate the problem of reservoir prediction from seismic in the latest Scotian Slope deepwater wells. A successful gas-bearing reservoir or at least sufficiently thick reservoir quality sands are required to calibrate the seismic response. The solution of amplitude and AVO anomalies is non-unique and coupled with the inherent error of the measurement the confidence level remains low.

Modern 3D seismic imaging is not free from problems of distortion during pre- and post-stack time and/or depth migration and this has been expressed by some operators and clearly comes from empirical observations but bears some consideration. The current 3D seismic data allows for accurate mapping of present-day structural closures, however it is still difficult to restore these features to a syndepositional topographic low that was capable of capturing turbidite sands. It requires a complete understanding of salt movement and its relationship with ongoing slope sedimentation. For the Scotian Slope, this geologic model remains not well understood.

5.8.3 Well Operations

No significant operational delays were encountered with the well until after the 298mm/11¾" liner was run to a depth of 4543m MD (Figure 128). Once the liner was run, considerable time was lost due to the loss of returns during cementing that resulted in a low leak off test (LOT). A cement squeeze was performed with no increase in LOT. A second cement squeeze was performed, with mud losses during the job, again with no increase in LOT. Difficulties were also experienced drilling out the cement retainer that was set prior to performing the second squeeze. Pre-spud, it was estimated the well could be drilled to the base-case TD (5025m MD) in 60 days. Although there were 16 days lost to operational problems, Balvenie was drilled in 67 days (7 days over AFE) because TD was called at 4750m MD, 275m shallower than planned.

5.8.4 Risk and Assessment

Balvenie lies in the Central Upper Slope of the Board's 2002 assessment. In this area, the play adequacy was deemed to be 64% using the following parameters:

- Source: 100%
- Reservoir: 80%
- Trap: 80%

The prospect adequacy was 25% for an overall adequacy of 16% or 1:6. The drilling results of Balvenie and the other adjacent slope wells required a reduction at the play level for reservoir adequacy and at the prospect level for net pay and drilling success ratios (see Section 7.2).

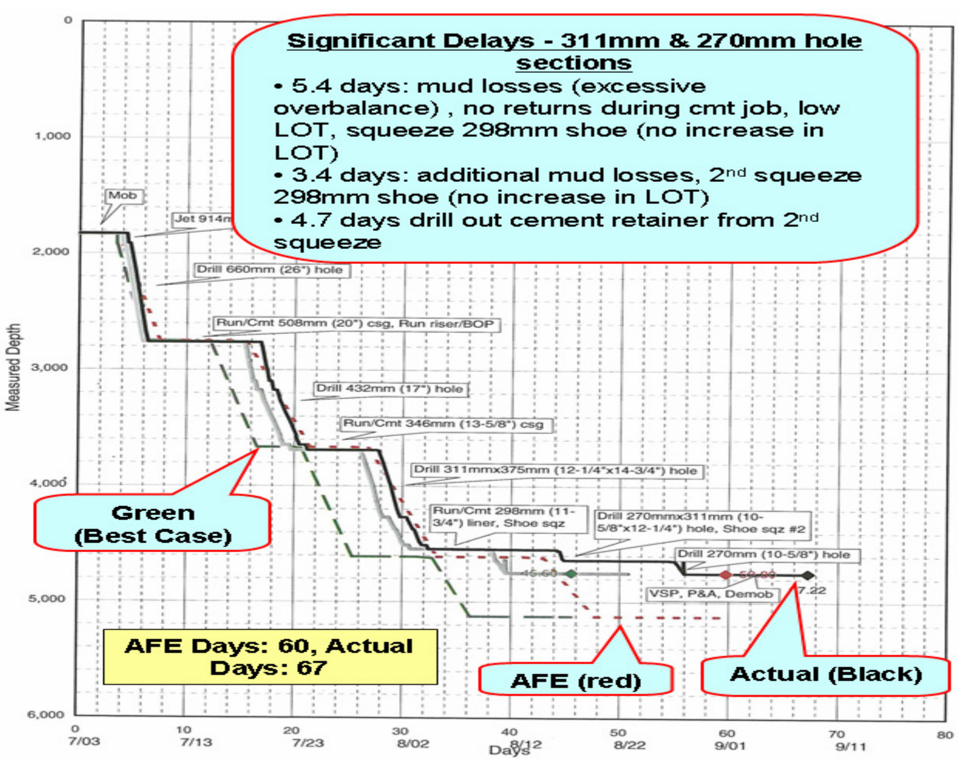


Figure 128. Balvenie B-79: Time vs. depth curves (actual and AFE).

5.9 EnCana Weymouth A-45 (2003/04)

Weymouth A-45 was EnCana's second exploration well in deepwater and the first subsalt test in the basin (Enclosure A). Using the Eirik Raude semi-submersible rig, the well was spudded on October 27, 2003 in 1690 metres of water and later abandoned with the rig released on May 18, 2004.

5.9.1 Objectives and Concepts

Weymouth's objectives were turbidite sands within the 4600–6400m interval in the lower Logan Canyon and Missisauga formations. These were deposited during major relative sea level lowstands and later covered beneath an allochthonous Argo salt body (Figure 129) (EnCana, 2004). The Weymouth prospect is a simple anticline with four-way dip closure formed by adjacent salt withdrawal on the flanks (Figures 130, 131). Initial salt movement driven by sediment loading provided topographic lows that allowed for ponding of turbidite sediments. Subsequent structural inversion provided the trap and the later emplaced salt canopy provided the seal.

Based upon well control from the Newburn and Annapolis wells, and seismic sequence stratigraphic modeling, a submarine fan play concept was postulated. However, it was acknowledged that little to no direct evidence existed to support the presence of reservoir and estimations of its quality. A schematic cross-section of the Weymouth prospect does not include the results of Newburn H-23 well (Figure 132). Suggested reservoir "geobodies" are tenuously linked to the shelf via an interpreted submarine channel west of the Alma field in the paleogeographic reconstruction (Figure 133).

Seismic interpretation in time and depth confirmed the structural configuration of the prospect with seismic amplitude measurements used to predict the reservoir and its parameters (Figure 134). Seismic resolution precluded detection of potential sands with thicknesses less than 20 metres.

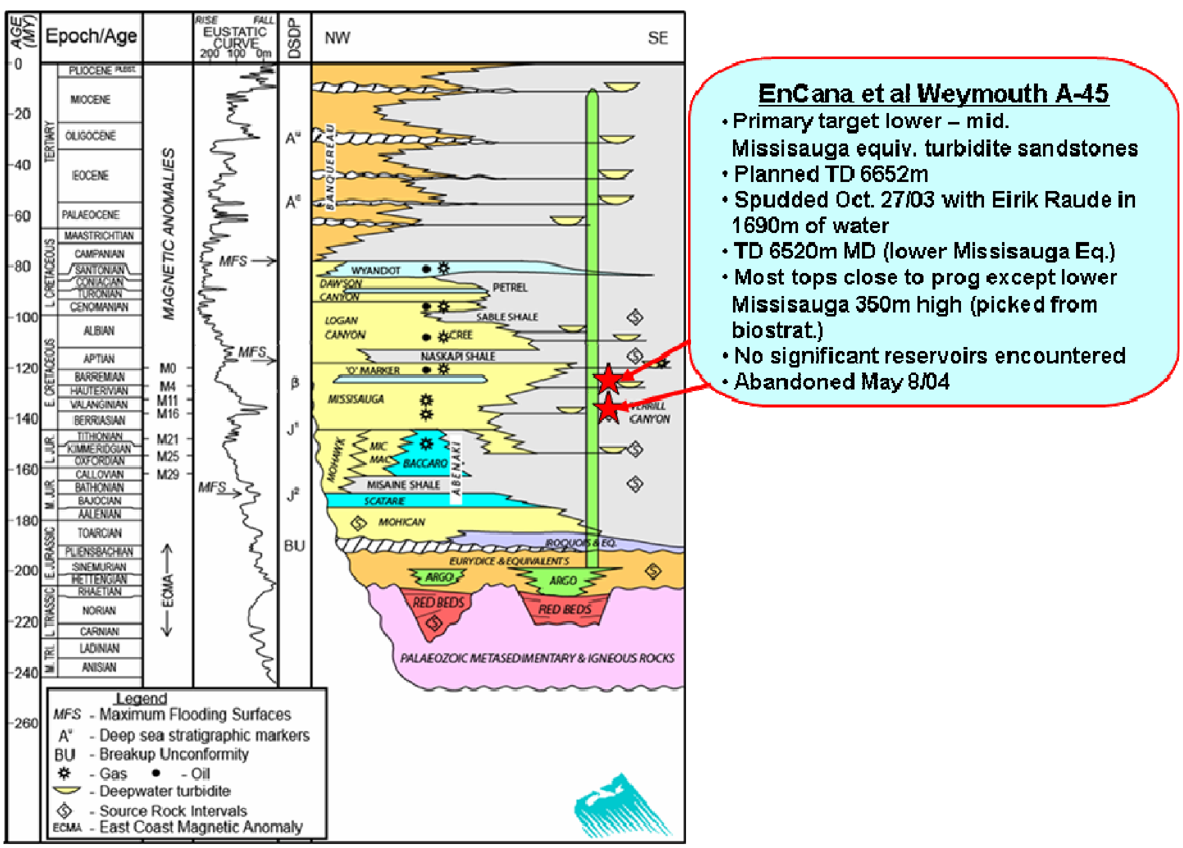


Figure 129. Stratigraphic chart showing target interval for Weymouth A-45.

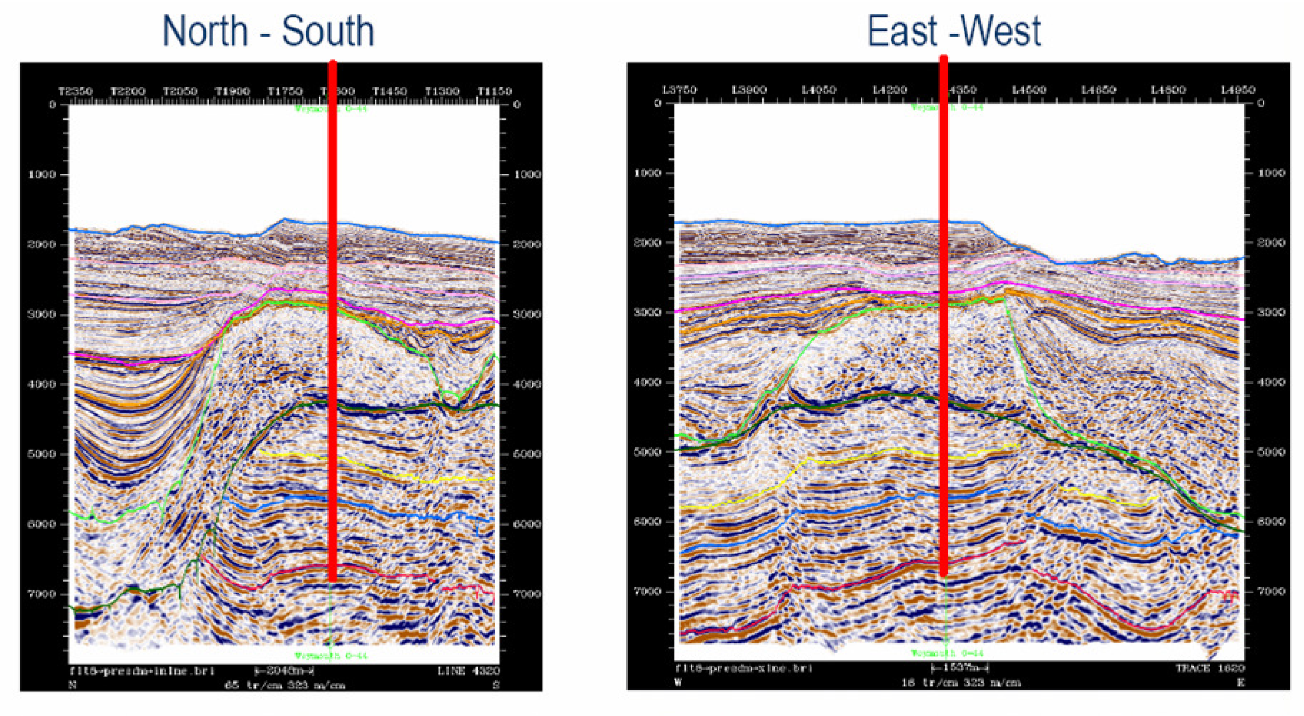


Figure 130. Strike and dip seismic sections (3-D) through Weymouth prospect (Weymouth ADW, used with permission).

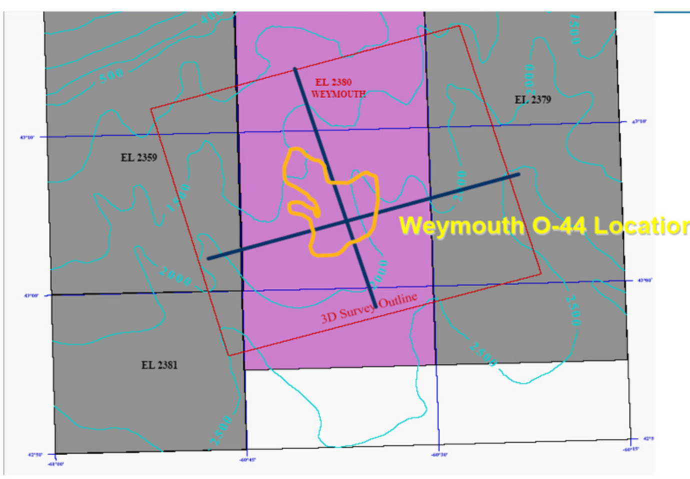


Figure 131. Bathymetric map over Weymouth prospect. Orange outline shows the structural closure of the subsalt target (Weymouth ADW Presentation, used with permission).

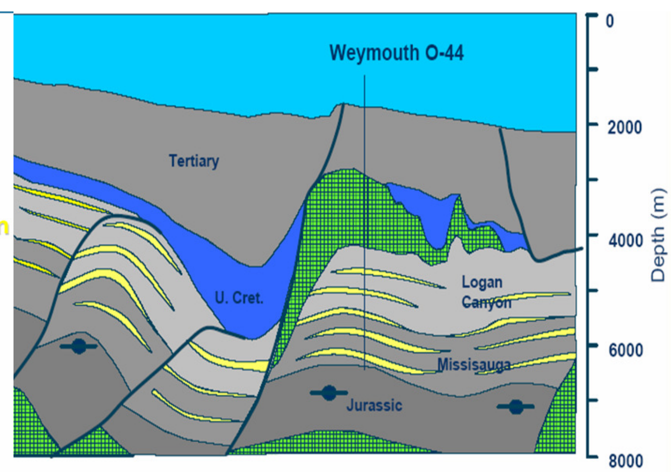


Figure 132. Schematic dip cross-section showing the play concept for Weymouth (Weymouth ADW Presentation, used with permission).

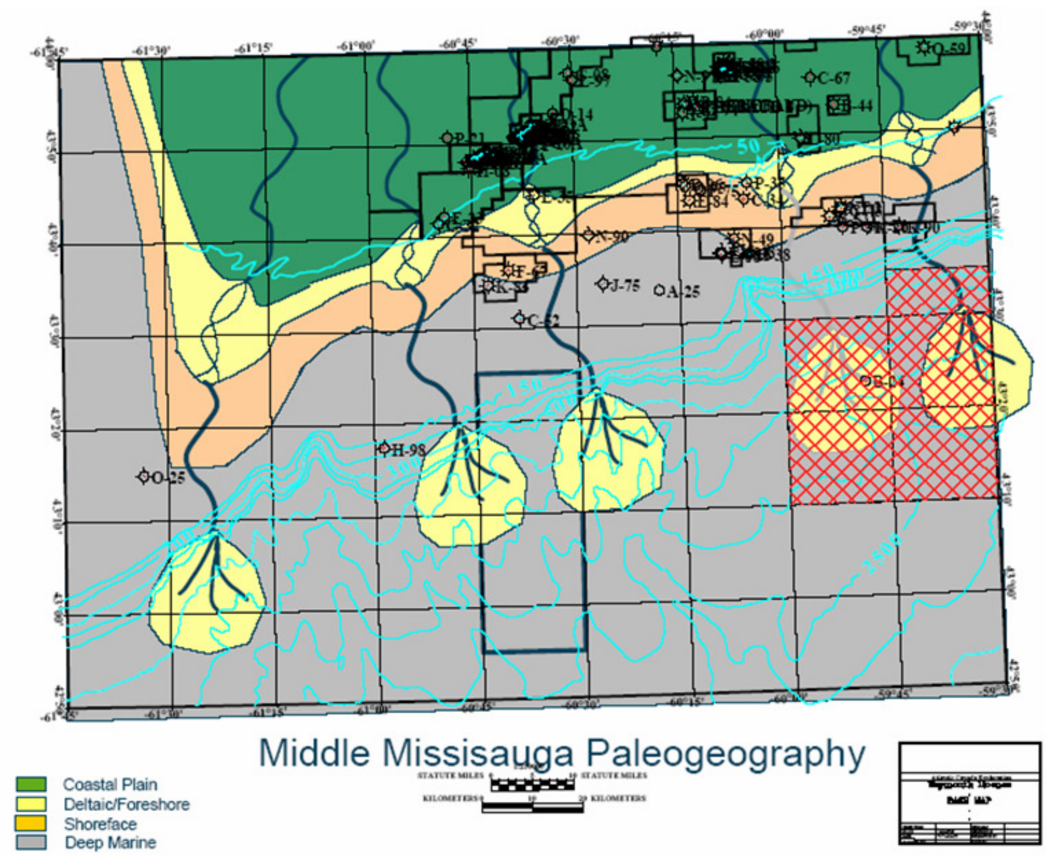


Figure 133. Paleogeographic reconstruction showing possible deepwater turbidite deposition pathways (Weymouth ADW, used with permission).

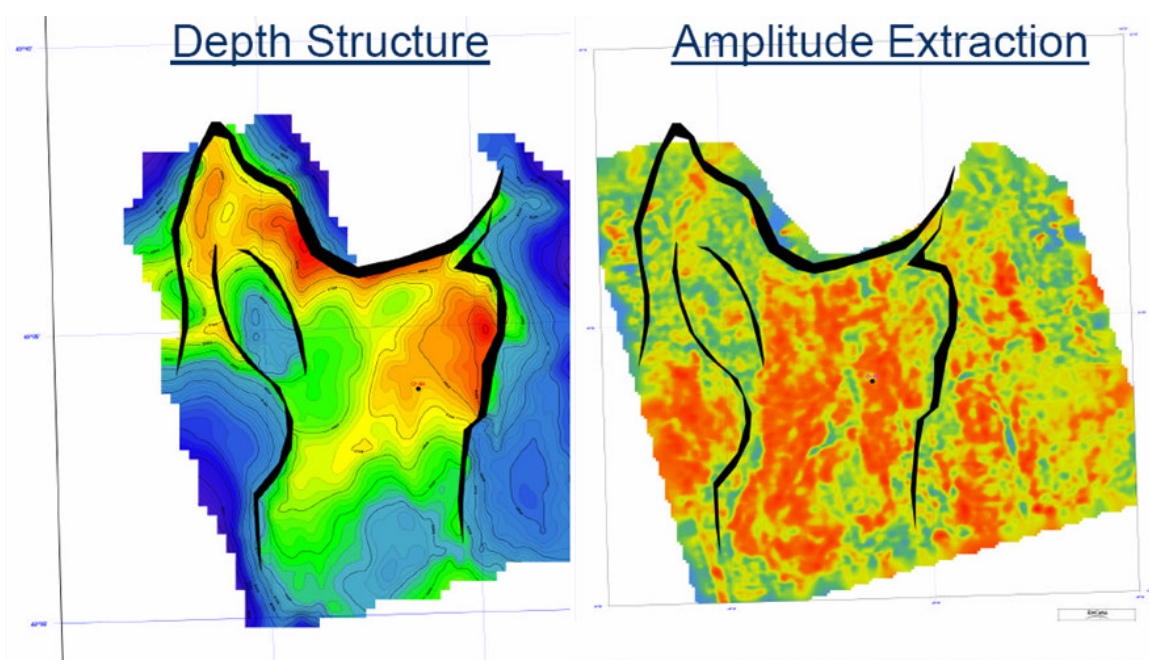


Figure 134. Top Missisauga equivalent 3-D depth structure and amplitude maps for Weymouth prospect (Weymouth ADW Presentation, used with permission).

5.9.2 Results

Drilling

The well was drilled to a total depth of 6520m MD / 6500m TVD ending in the lower Missisauga formation equivalent (Enclosure B) (EnCana, 2004). Planned total depth was 6652m TVD). Biostratigraphic age data was not available for the preparation of this report so the precise ages of the units encountered are unknown. Formation tops used in this study were lithological ones obtained from the Well History Report (EnCana, ibid.). The well's primary targets were middle and lower Missisauga formation equivalent turbidite sands trapped beneath a large salt tongue / canopy. Well results indicated that very little sand was encountered in the target interval, which consisted mainly of shale with minor siltstone and marl.

The Argo formation salt section was 1507m thick and was described as primarily clear to white halite (Figure 135). No stray sands were encountered within the salt. Approximately 260m below the base of salt in the top of the Naskapi equivalent, the well took a 6m^3 kick at 4612m MD that generated a gas show of 638tgu/30u. The drill pipe became differentially stuck and as a result had to be severed, the well backed off, and then sidetracked. When the kick zone was penetrated in the sidetrack borehole, it was found to be a 5m thick overpressured zone with a few thin (<1m) porous, very fine-grained, silty sandstone beds (Figure 136). The mud weight used to control the kick allowed the operator to estimate the zone's pore pressure with reasonable accuracy and clearly indicated that the well had indeed drilled into overpressured formations. Overpressure occurred between base of salt at 4348m MD and the kick zone at 4612m MD. It is estimated that top overpressure occurs at or near base of salt at 4348m MD.

Trace amounts of "liquid hydrocarbons" were circulated out from the kick zone at 4612m MD, and small volume samples were recovered from the mud pits and BOPs. No analysis is available, although based on the magnitude of the mud-gas show during drilling, it appears the zone is gas-charged as so the recovered hydrocarbons may include traces of associated condensate.

The upper Missisauga section consisted mainly of shale, with minor siltstone and marl, which was drilled without any significant gas shows. A 4m sandy siltstone that was wet on logs, was encountered at 5214m MD. It had fair to good porosity (16% maximum, 14% average) and permeability such that wireline MDT formation pressures could be obtained (Figure 137). The primary targets within the middle and lower Missisauga equivalents were determined to be thin, tight siltstones, marls and limestone stringers without any significant gas shows. The only interval of note is a 20m thick zone at the top of the middle Missisauga equivalent that consisted of interbedded siltstone and shale with very fine-grained, tight, sandstone stringers (<1m). No significant gas shows were detected within the entire Missisauga formation succession.

Twenty-four rotary sidewall cores (SWCs) were successfully acquired in the 7 7/8"/200mm hole section within the middle and lower Missisauga formation (Figure 137). Most SWCs are described as dark grey shale, while a few samples had siltstone and/or carbonaceous laminations. Photographs of selected SWCs are shown in Figure 138 with annotated depths. Although the dominant lithology of the middle and lower Missisauga is shale, the gamma ray log from 5900–6520m MD (TD) shows a considerably "cleaner" gamma response compared to the shale units in the overlying Naskapi and upper Missisauga. This response appears to be caused by varying amounts of disseminated and/or finely laminated carbonate material within the shales. Similar gamma ray responses from calcareous shales were also noted in the Shubenacadie H-100 and Balvenie B-79 wells.

Due to the lack of reservoir development, only 10 Modular Dynamic Tests (MDTs) were attempted in the entire well. Two MDTs were attempted near 5019m MD in the lower Naskapi but the tests were dry (tight). Eight MDT pressure measurements were attempted between 5214–5218m MD in the upper Missisauga wet siltstone as described above. Of the eight attempts only three valid measurements were obtained and these pressures were all acquired from the same depth (5215.8m MD). The other five attempts were either dry tests or supercharged. Due to the lack of reliable MDT data and the clustering of the points, it was not possible to derive a pressure gradient.

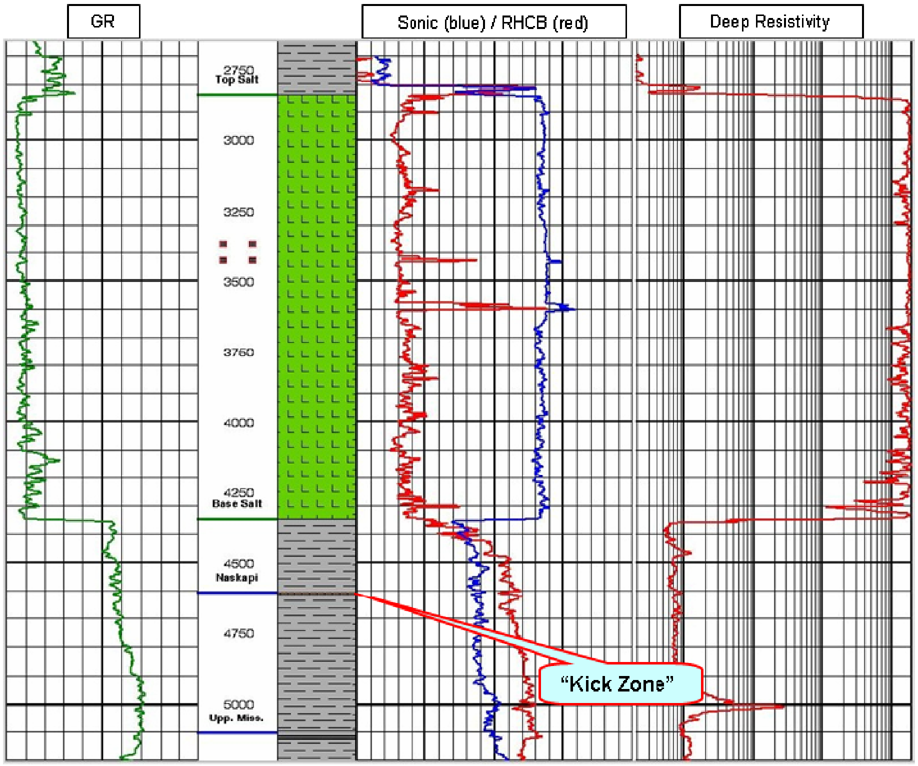


Figure 135. Weymouth A-45: Well logs from top salt to top Missisauga.

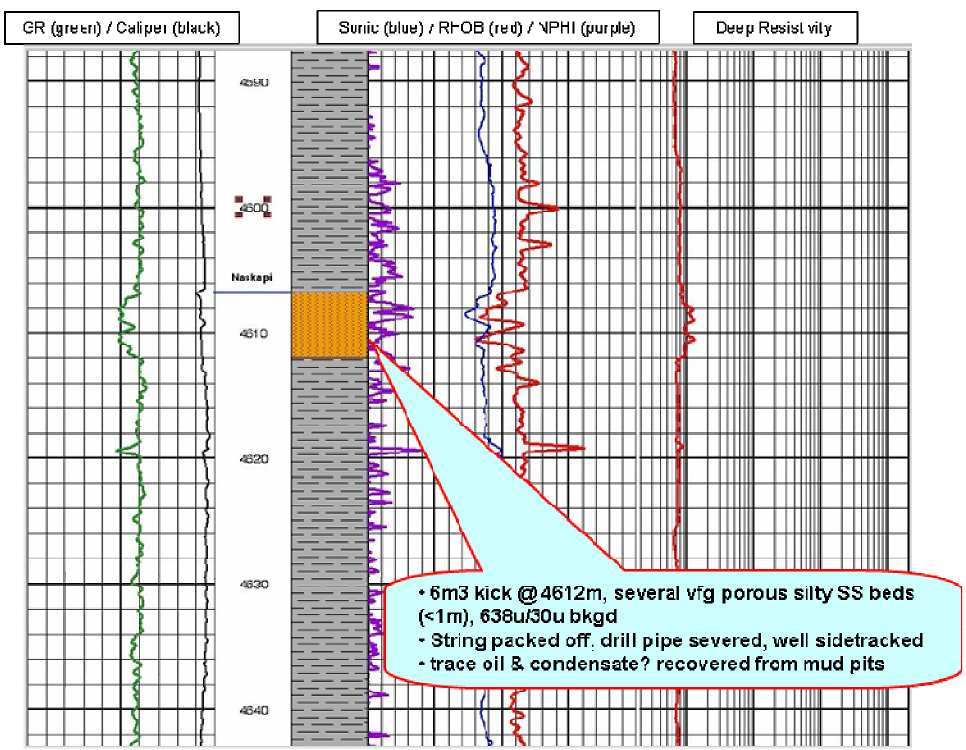


Figure 136. Weymouth A-45: Well logs from Naskapi-equivalent (Aptian?) "kick zone".

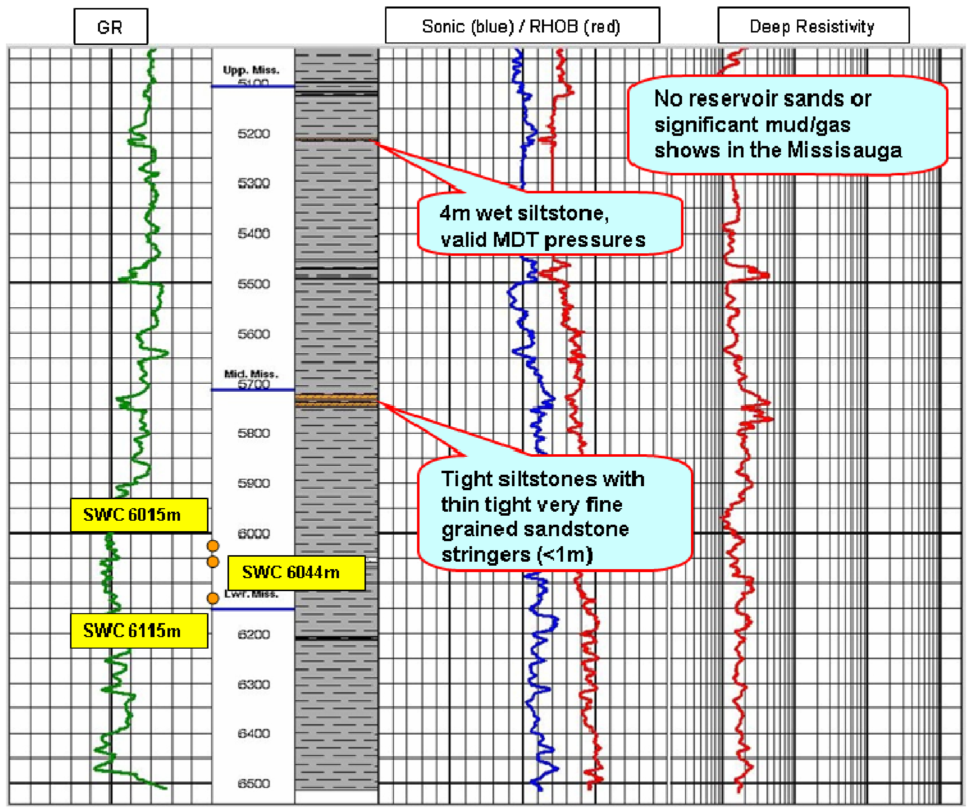


Figure 137. Weymouth A-45: Well logs from target Missisauga interval (Barremian – Valanginian?).

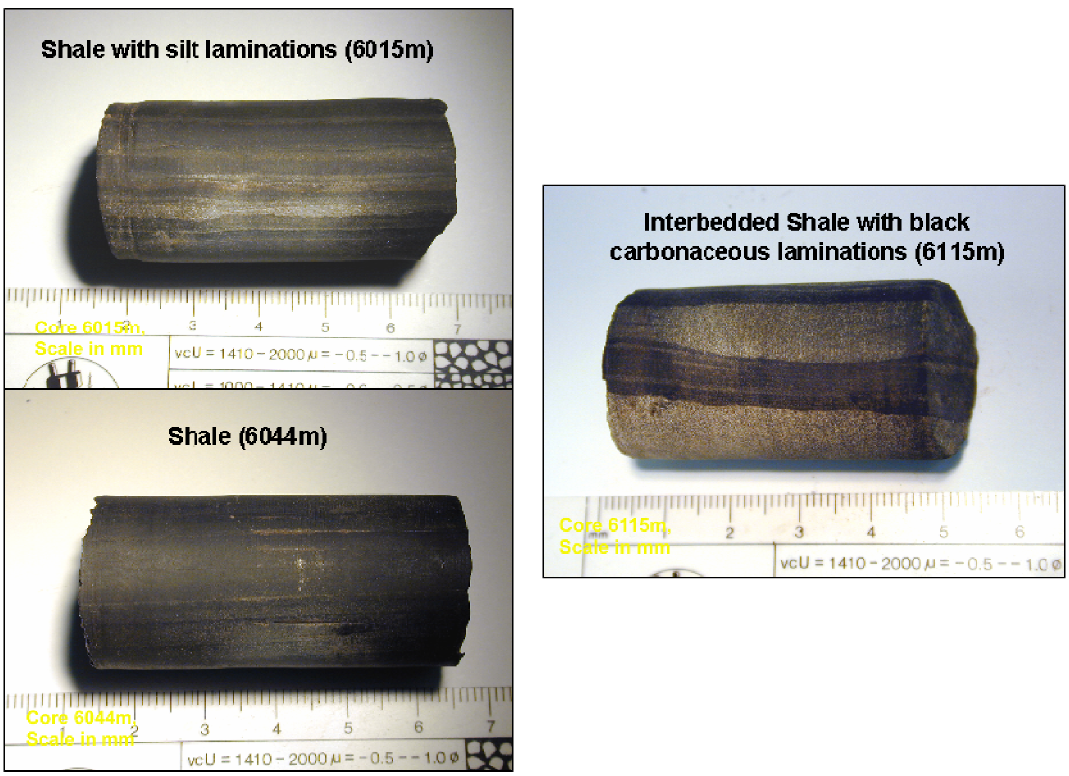


Figure 138. Sidewall Core photos from Weymouth A-45 (see figure 137 for depths).

Seismic Interpretation

Figure 139 is a TGS 2D dip-line through the Weymouth structure with the target section below the salt poorly imaged as is the base of the salt. Figure 133 reveals EnCana's pre drill outline of the Weymouth structure and its location relative to the 3D survey. EnCana's interpretation on their 3D data and shows that the subsalt imaging is far superior to the 2D data (Figure 130). The associated depth map and amplitude extraction on the target horizon are shown in Figure 134. The well seismic synthetic shown in Figure 140 illustrates the challenge to pick the base of the salt from the 2D line. This further emphasizes the vital importance of a good 3D data set.

The 3D seismic dataset was adequate for interpreting the extent of the salt body and the structural configuration of the Weymouth prospect. The presence of salt with associated salt withdrawal zones, salt welds, and salt stalks makes it very difficult to formulate a depositional model that describes the transport system needed to deliver sand from the shelf to the Weymouth structure. There exists seismic evidence for channel systems on the shelf above the Weymouth block, but these channels can only be observed landward of the present day slope break. With no seismic indications of a channel/fan system past the slope break, and no data to enable calibration of the mapped amplitudes to any reservoir properties, this play test must be regarded as having had a very low probability of encountering sand in a shale prone slope environment.

Biostratigraphy, Paleoenvironment, Geochemistry

Biostratigraphic and geochemical information on this well from the operator or outside sources was not available to the authors during the preparation of this report.

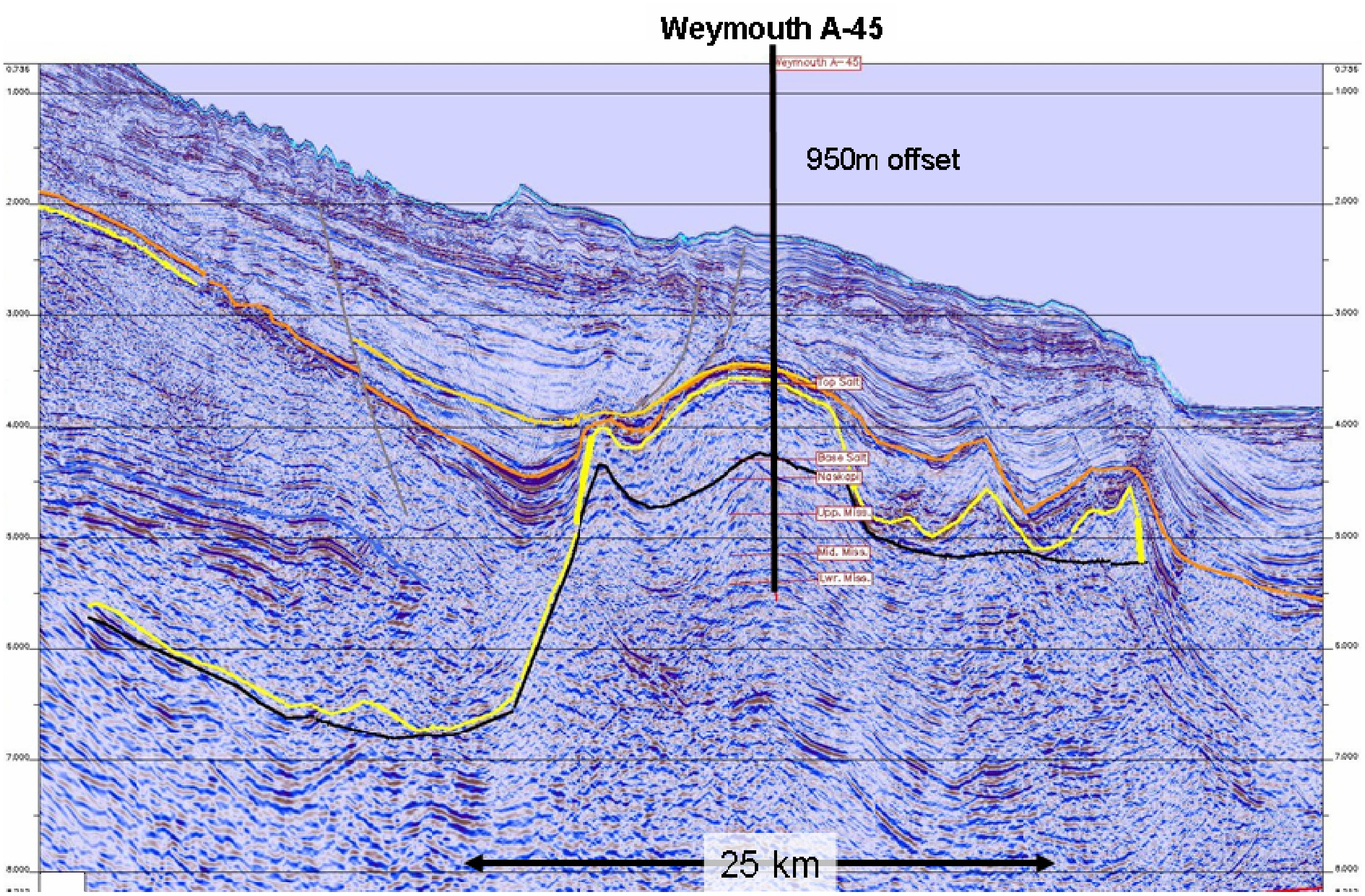


Figure 139. Seismic dip line (2-D) through Weymouth A-45. Black horizon is the base of the salt. Data courtesy of TGS-NOPEC.

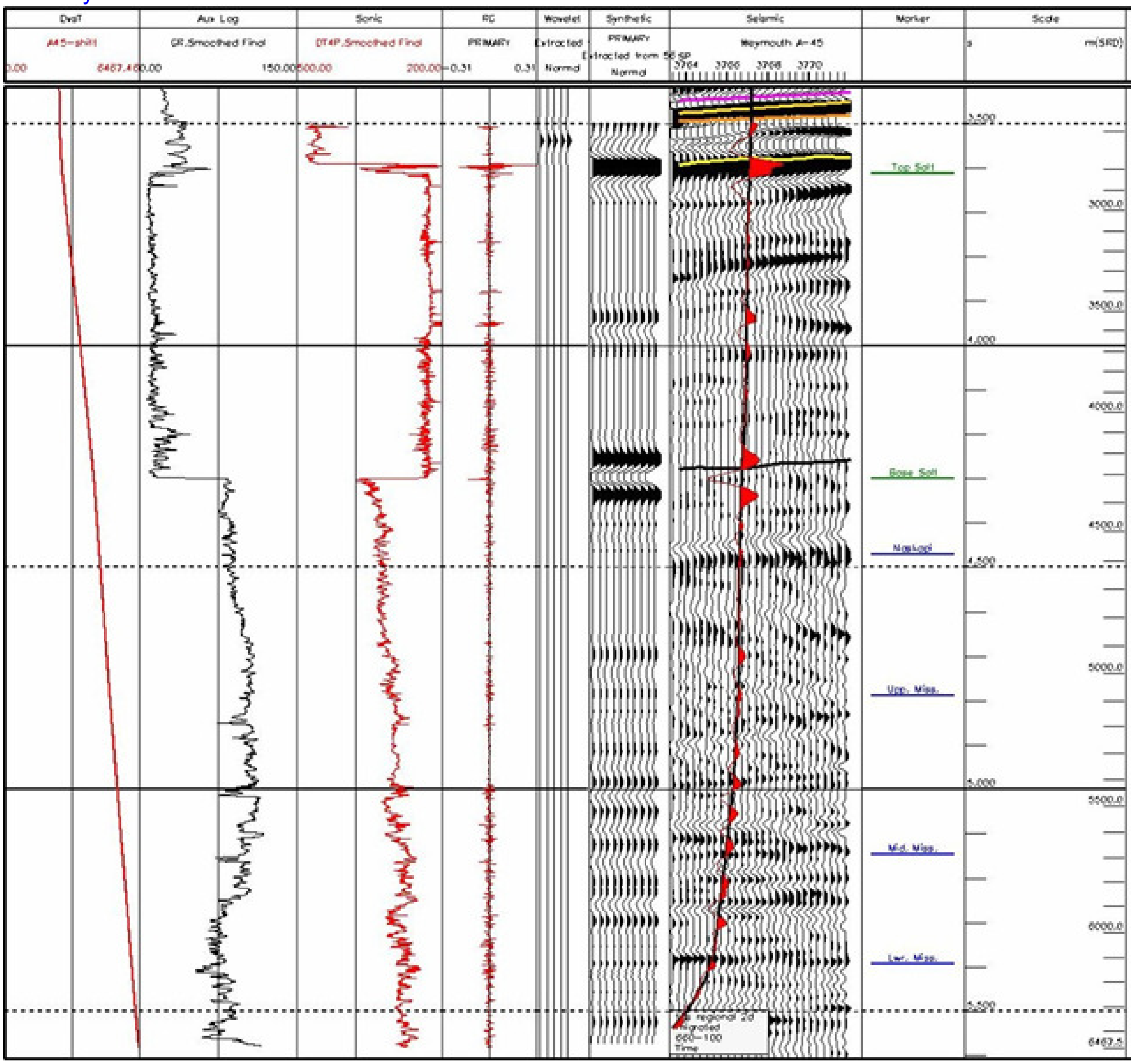


Figure 140. Weymouth A-45: Synthetic Seismic.

Exploration Implications

Although Weymouth's target interval was determined to be mainly shale, there was little evidence supporting the presence of a paleodepocentre despite the conceptual thinking. For the Scotian Slope, incorporation of seismic data to an earth systems model requires more direct evidence of channel/fan systems. However, the poor resolution of the older pre-Tertiary succession makes this very difficult. The inclusion of faults and salt welds to this setting further reduces the already low confidence in seismic imaging and earth modeling exercises.

Once again, the main geological risk appears to be the back-modeling of a present-day structural high into an original mini-basin or topographic low that captured turbidite sands. As an illustrative point, the flanking syncline on the north side of the Weymouth salt body was a true syndepositional topographic low. It was not considered to contain reservoir sands but instead full of high amplitude upper Cretaceous chalks and marls. Such considerations are not valid given that mini-basins have yet to be drilled on the Scotian Slope, their stratigraphic succession confirmed, calibrated to seismic, and comparison of the results of pre-drill modeled successions versus actual well results.

5.9.3 Well Operations

No significant delays were experienced in the up-hole and salt sections of the well (Figure 141) (EnCana, 2004). The salt section was drilled without incident and actually drilled faster and with fewer problems than anticipated such as trapped overpressured zones, problems drilling the anticipated "gumbo zone" at base of salt, etc.

No major time delays were experienced until the well took a 6m^3 gas kick in the top of the Naskapi member equivalent at 4612m MD. Sixteen days were lost controlling/circulating out the kick, trying to free the stuck drill pipe, severing the pipe and kicking off the sidetrack. From the base of salt to TD, all formation Leak Off Tests (LOT) were considerably lower than originally modeled, being 100–250 Kg/m^3 mud weight equivalent below expected values. In addition, only small increases in LOT (i.e. rock strength) were gained as the well was deepened.

Due to increasing pore pressures and low leak-off values, it became necessary to run an extra liner. It was also necessary to run casing strings/liners shallower than planned as mud weights were often close to leak-off values (i.e. low kick tolerance) resulting in lost circulation and unstable borehole conditions. In some instances cement squeezes were attempted to improve shoe strength. However, in most cases, this resulted in no significant increase in formation integrity. One possible explanation for the low LOTs below the base of salt may be the low density of the overlying salt. This prevents the sub-salt formations from fully compacting and lithifying resulting in a shale-dominated succession that has not yet fully dewatered.

Many of the well bore sections in Weymouth were drilled utilizing a near-bit reamer that was run behind the drill bit to widen the hole to the required size. The reamer was expected to optimize drilling performance and was based on Gulf of Mexico "best practices" for sub-salt wells. However, significant mechanical problems were experienced with the reaming equipment such as the inability to effectively ream since the reamer blades would not remain open, broken reamer blades due to excessive torque/jarring, etc.

All the above problems created significant time delays that invariably resulted in well costs in excess of the AFE. The well was drilled and abandoned after 185 days, and of these, 58 days were in excess of the original planned AFE.

5.9.4 Risk and Assessment

The Weymouth well lies in the Central Canopy Complex of the Board's 2002 assessment. The major assigned risk in this region was presence of reservoir. The play adequacy of 17% was based on:

- Source: 80%
- Reservoir: 30%
- Trap: 70%

The prospect adequacy was 10% hence the overall chance of success for that first well was 1.7% or 1:59. The well results have little to no effect on this poorly understood play due to the lack of seismic support for recognition of feeder and depositional systems.

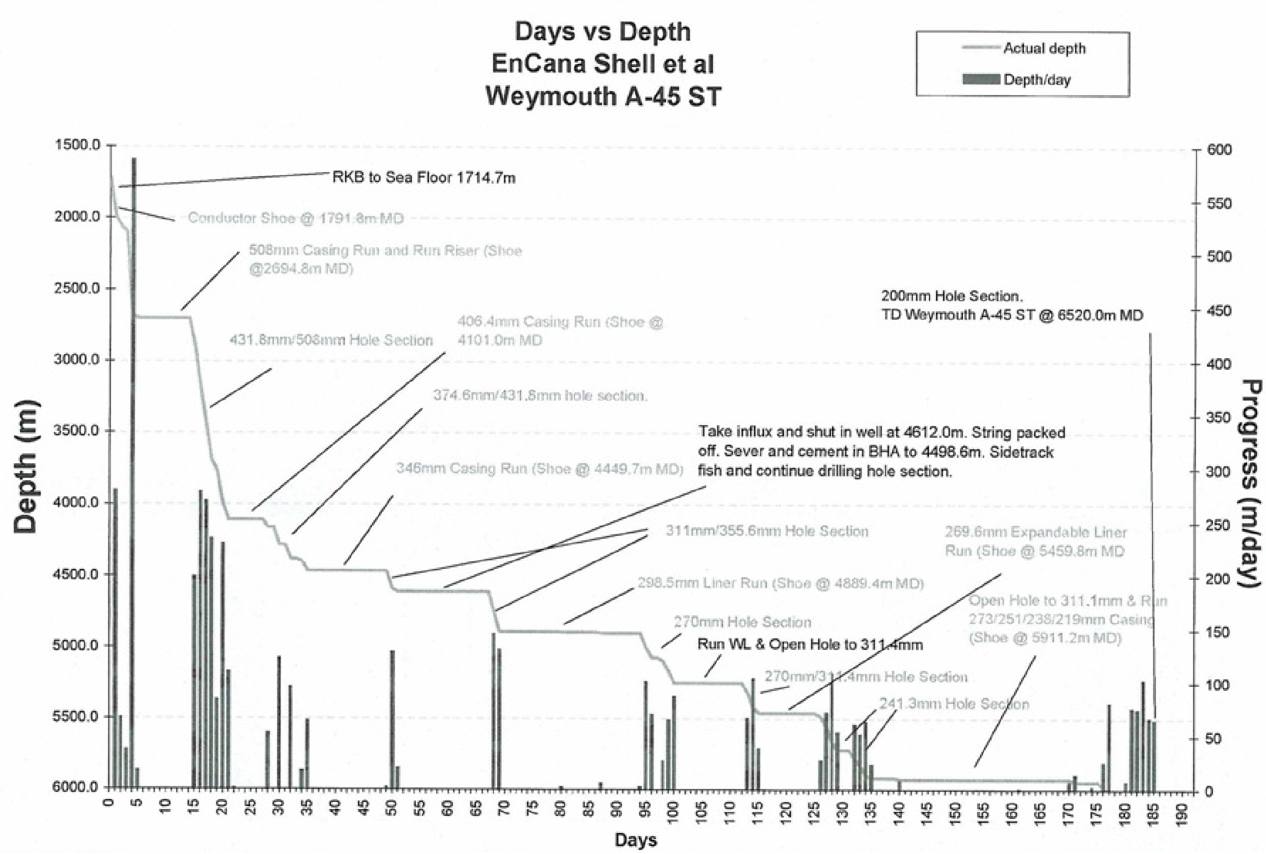


Figure 141. Drilling curve for Weymouth A-45 (actual).

5.10 Marathon Crimson F-81 (2004)

Marathon's second well in the deepwater was Crimson F-81; a follow-up to Annapolis G-24 gas discovery located about nine kilometers to the southeast (Enclosure A). The well was spudded on June 18, 2004 and the rig released on September 10, 2004 after abandonment. Crimson F-81 was drilled by the Deepwater Pathfinder drillship in 2091.5m of water, which to date is the greatest water depth of any well offshore Nova Scotia.

5.10.1 Objectives and Concepts

The Crimson reservoir objectives were Early Cretaceous deepwater sands deposited seaward of the sand-rich Sable paleodelta (Figure 142) Marathon, 2005). Specifically, the F-81 well was targeting an interpreted more sand-prone area of the Annapolis turbidic submarine fan system within which the H, L and M sands were found to be gas-bearing (Figure 92). The target was described as a faulted anticlinal feature developed during the Late Cretaceous as a result of salt withdrawal (Figures 143 & 144).

The results of the Annapolis well encouraged the operator to expand the seismic mapping of interpreted deepwater depositional fairways within the Annapolis/Crimson mini-basin complex. Figure 145 is a facies map at a time of maximum regression (Valanginian/Hauterivian) showing the hypothesized deepwater fairways feeding the submarine channels. An enlargement of this map (Figure 146) shows in more detail the revised post-Annapolis interpretation. Depth maps were generated and observed isopach thickening of the reservoir zones relative to Annapolis was interpreted as representing a more sand-prone area (Figure 145). The key point for a reservoir-rich depocentre is the concept of a syndepositional positive relief salt feature backstopping sand-rich fan complexes on the up-dip side.

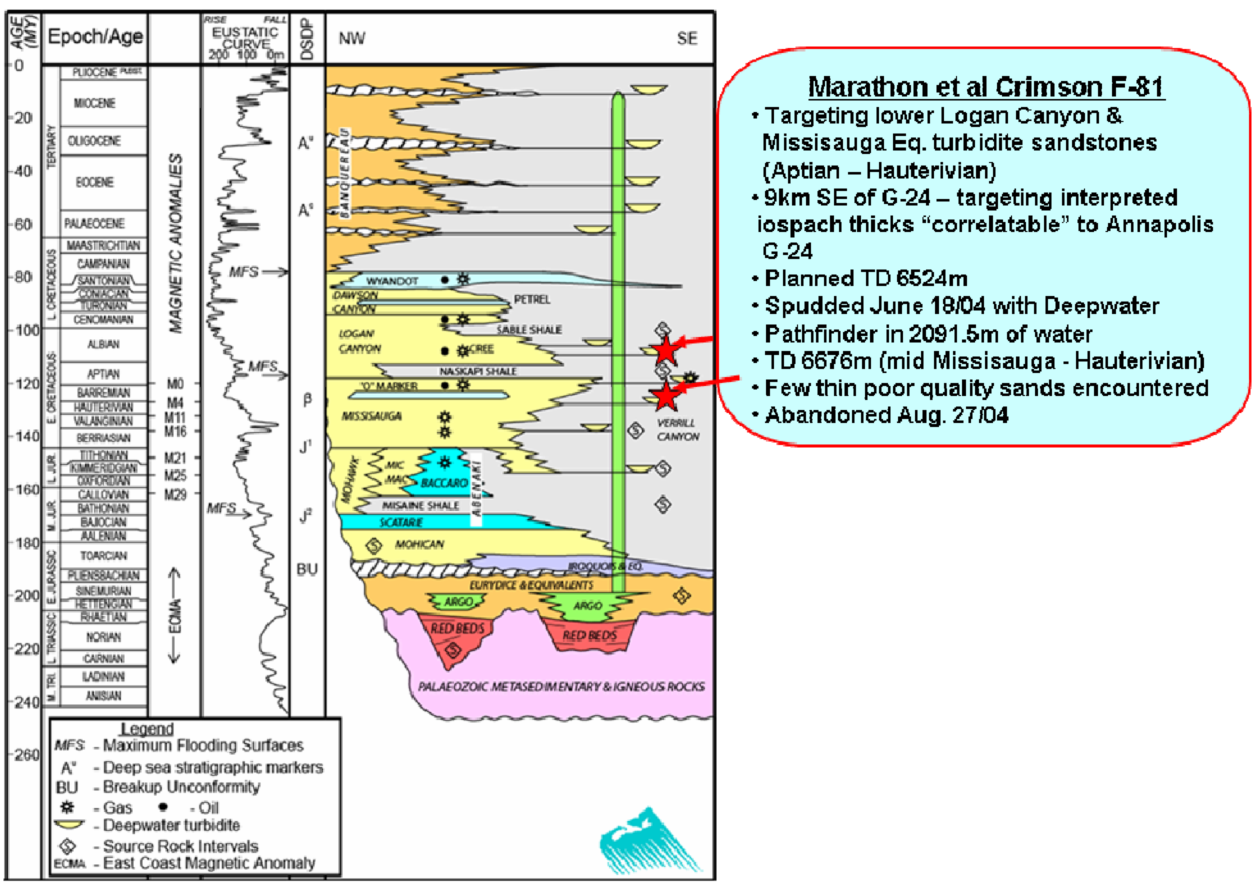


Figure 142. Stratigraphic chart showing target intervals for Crimson F-81.

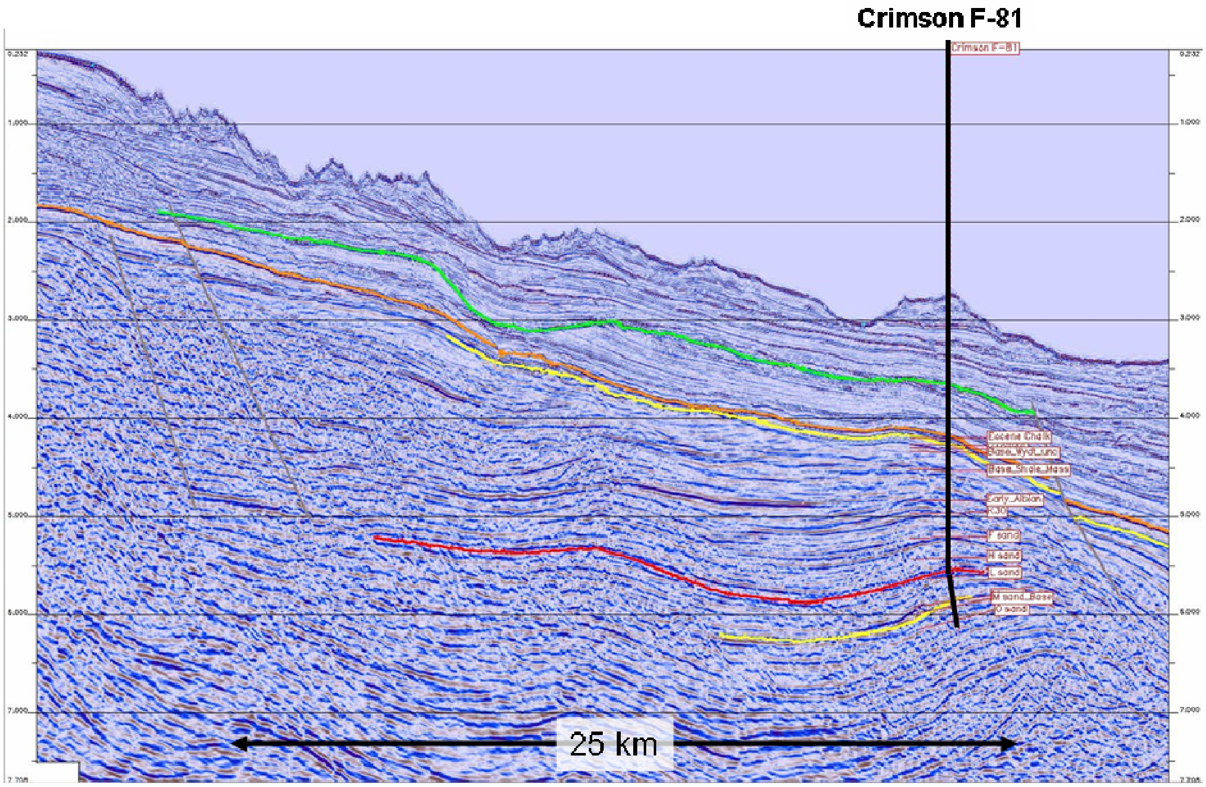


Figure 143. Profile of the Crimson structure. Data courtesy of CGG-Veritas.

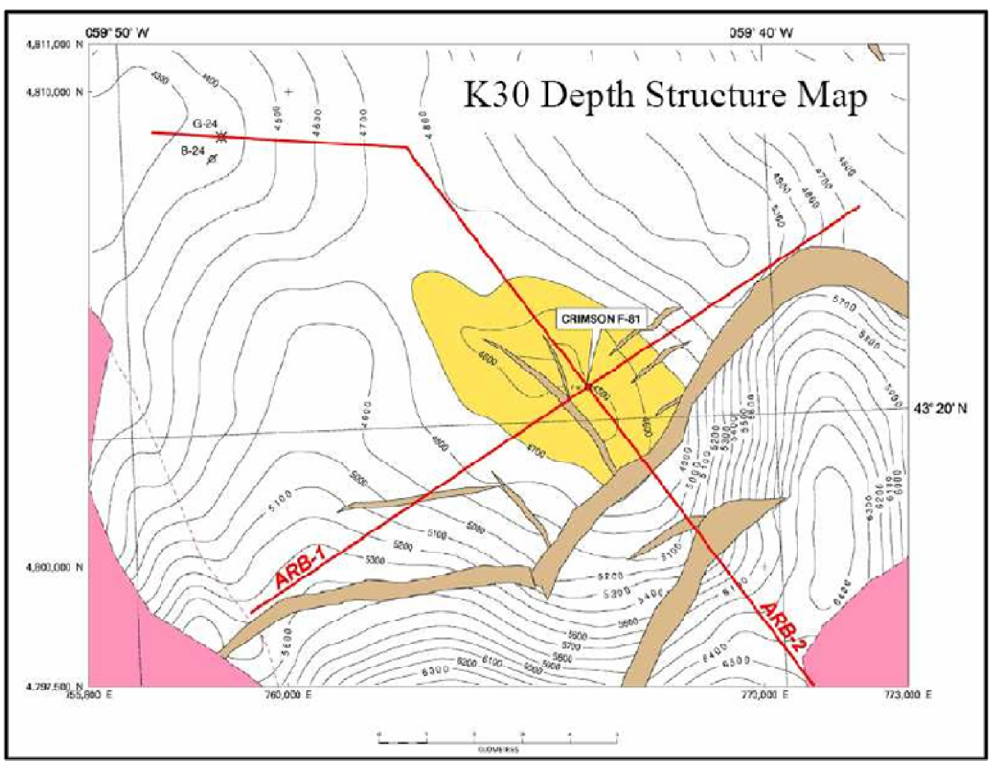


Figure 144. Depth structure map for the K30 horizon (Albian) at the Crimson location (Crimson ADW, used with permission).

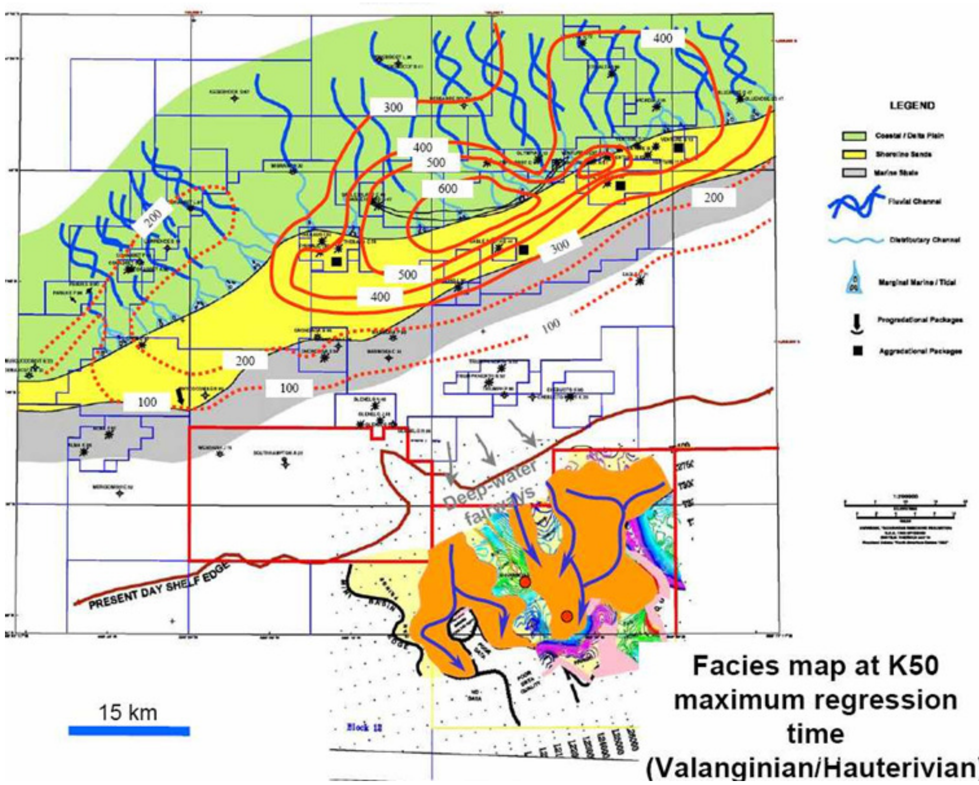


Figure 145. Depositional model for Valanginian/Hauterivian deep-water intervals at the Annapolis-Crimson location (Crimson ADW, used with permission).

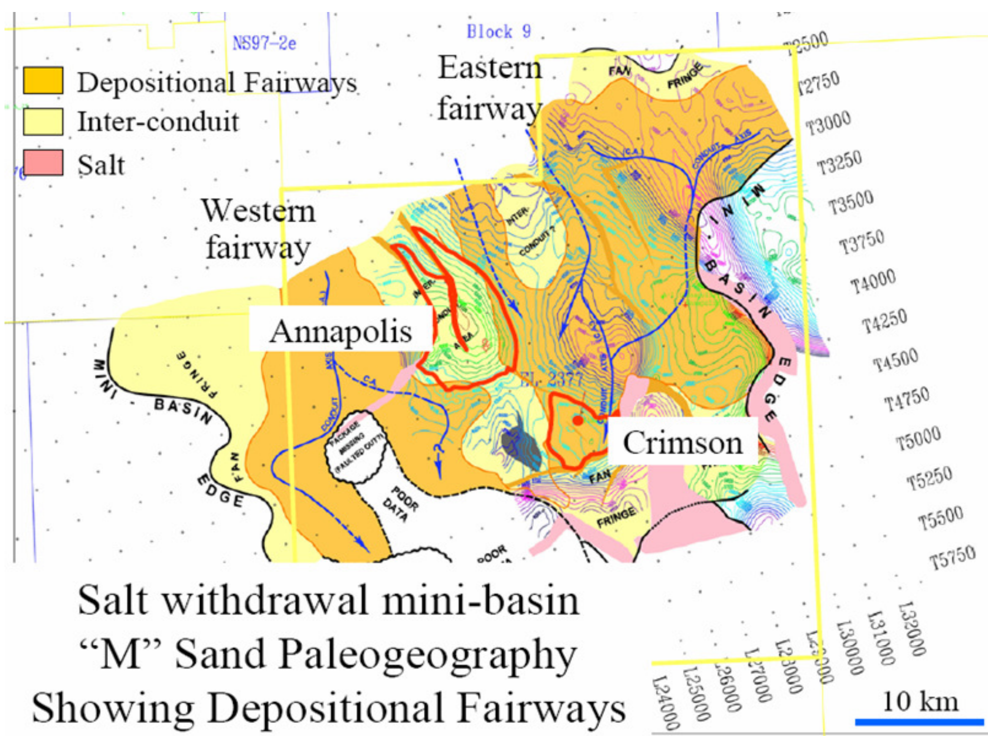


Figure 146. Depositional model for the "M" sand interval at the Annapolis-Crimson location (Crimson ADW, used with permission).

5.10.2 Results

Drilling

The Crimson F-81 well was drilled to a TD of 6676m MD (planned TD 6524m) finishing in the middle Missisauga equivalent section of Early Hauterivian age (Enclosure B) (Marathon, 2005). The well targeting interpreted isopach thicks thought to be correlative to the H, L and M zones encountered in the Annapolis G-24 well 9km to the northwest. No significant hydrocarbon bearing zones were encountered in Crimson. Reservoir quality was generally much poorer than Annapolis consisting of thin, tight, very-fine to fine-grained sandstones and siltstones in a shale dominated succession.

Due to the lack of reservoir development in F-81, lithologic and seismic correlation of the Annapolis H, L and M zones with equivalent strata at Crimson is difficult because of seismic character variability and the thinness of the zones. Notwithstanding these difficulties, the operator defined four zones in Crimson as the F, H, L, M and O Sands. With the exception of the O Sand, these "sands" are actually gross intervals which consist of thin sands, silts and shales.

The F Sand was encountered at 4899m MD and is the shallowest zone (Figure 147). It consists of very fine- to fine-grained, thin, tight sandstones and siltstones with an average porosity of <8%. No shows were detected during drilling which suggests the zones are wet. The Annapolis G-24 equivalent zones, the H, L and M Sands, were encountered at 5264, 5593 and 6040m MD respectively, with all consisting of very fine- to fine-grained thin, tight sandstones (porosity <6%) and siltstones. These zones did not generate any mud-gas shows during drilling and are likely water wet (Figures 148, 149 & 150).

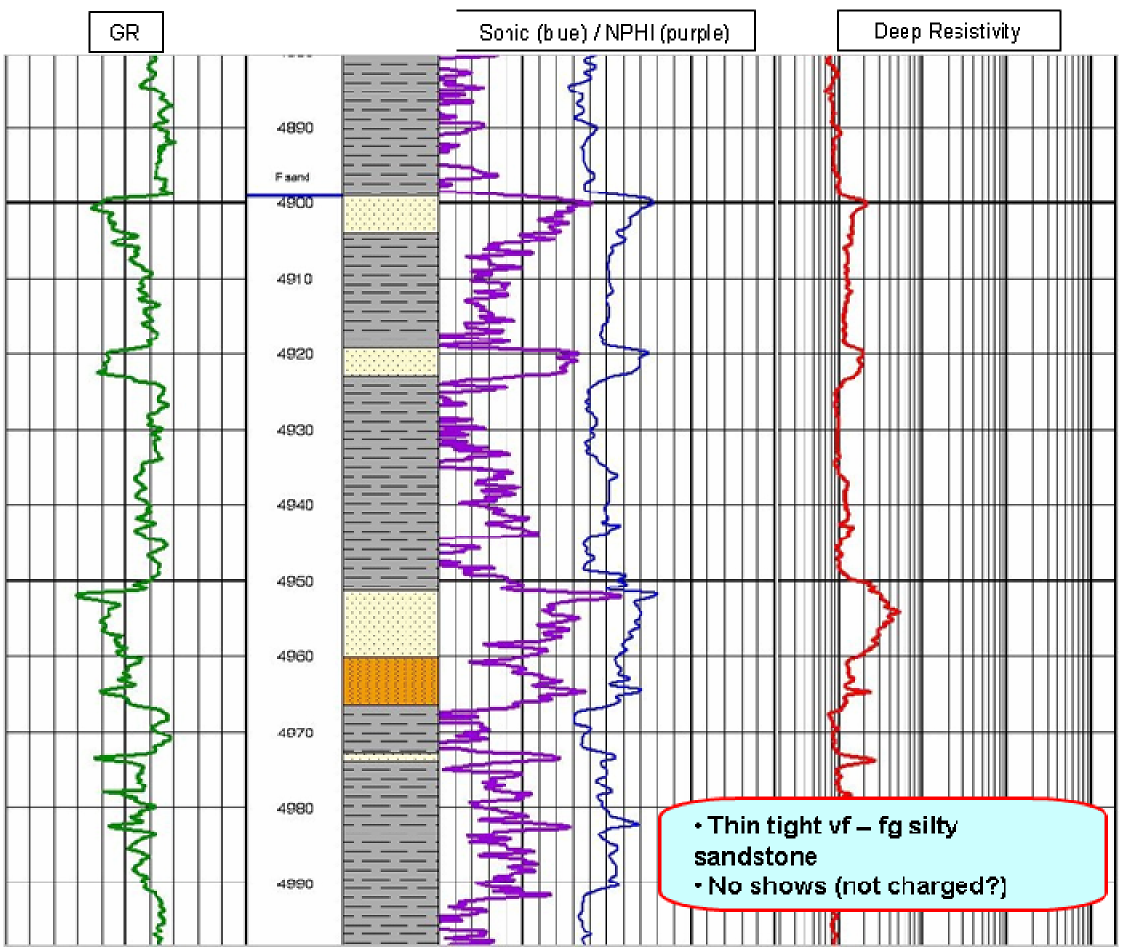


Figure 147. Crimson F-81: Well logs from the "F" sand interval (mid Barremian).

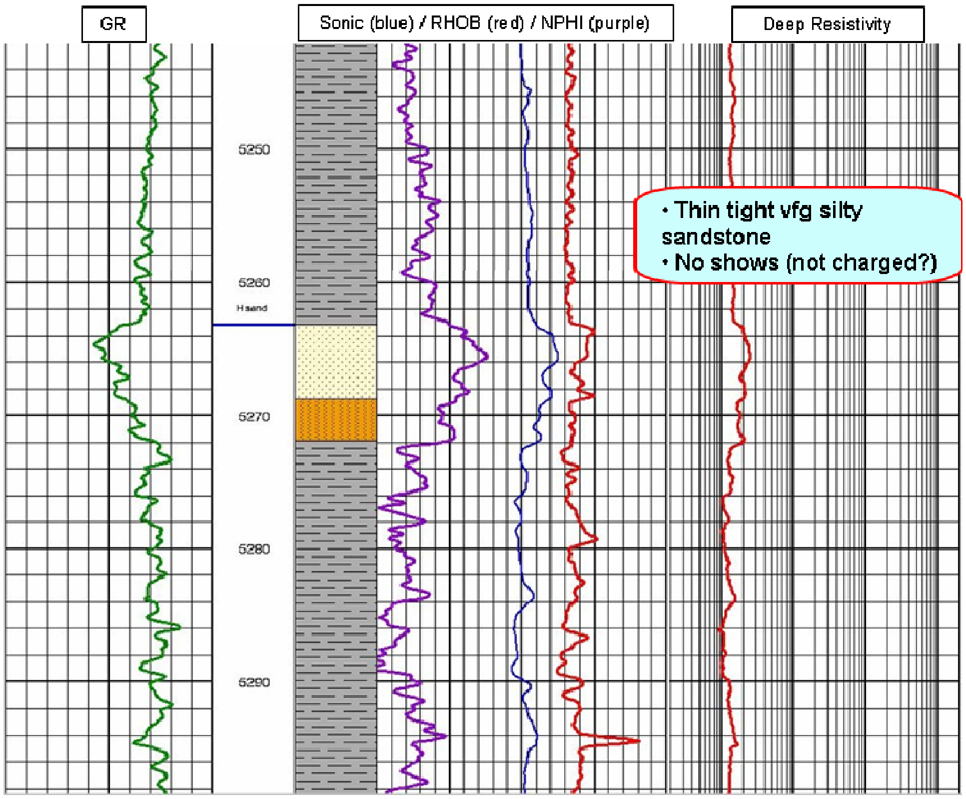


Figure 148. Crimson F-81: Well logs from the "H" sand interval (Early Barremian).

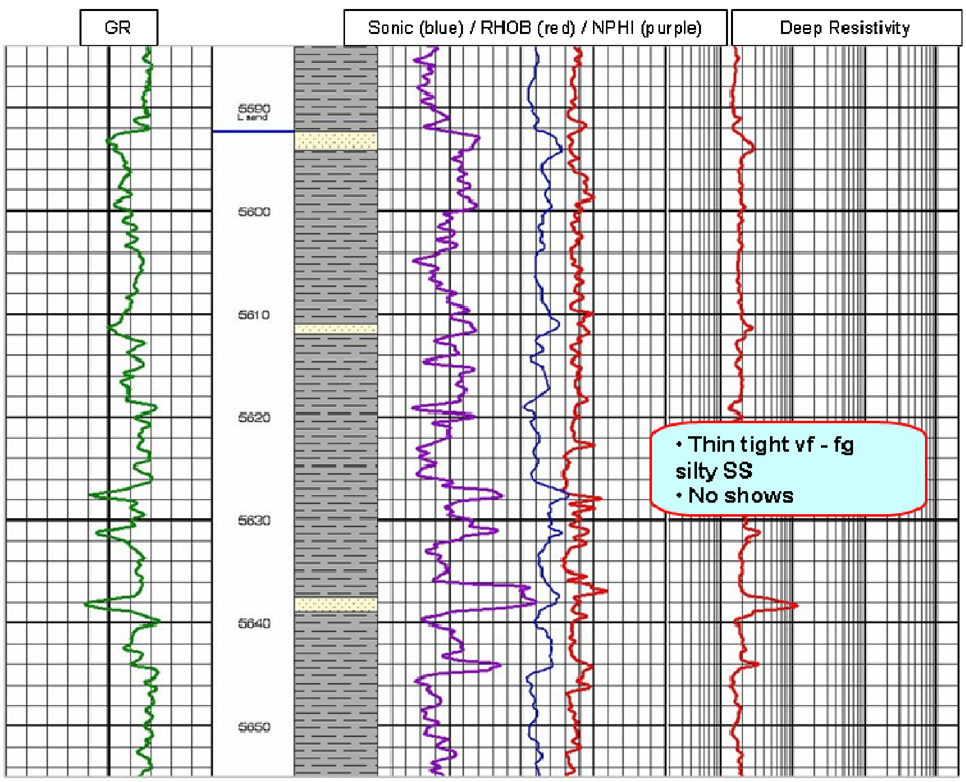


Figure 149. Crimson F-81: Well logs from the "L" sand interval (Late Hauterivian).

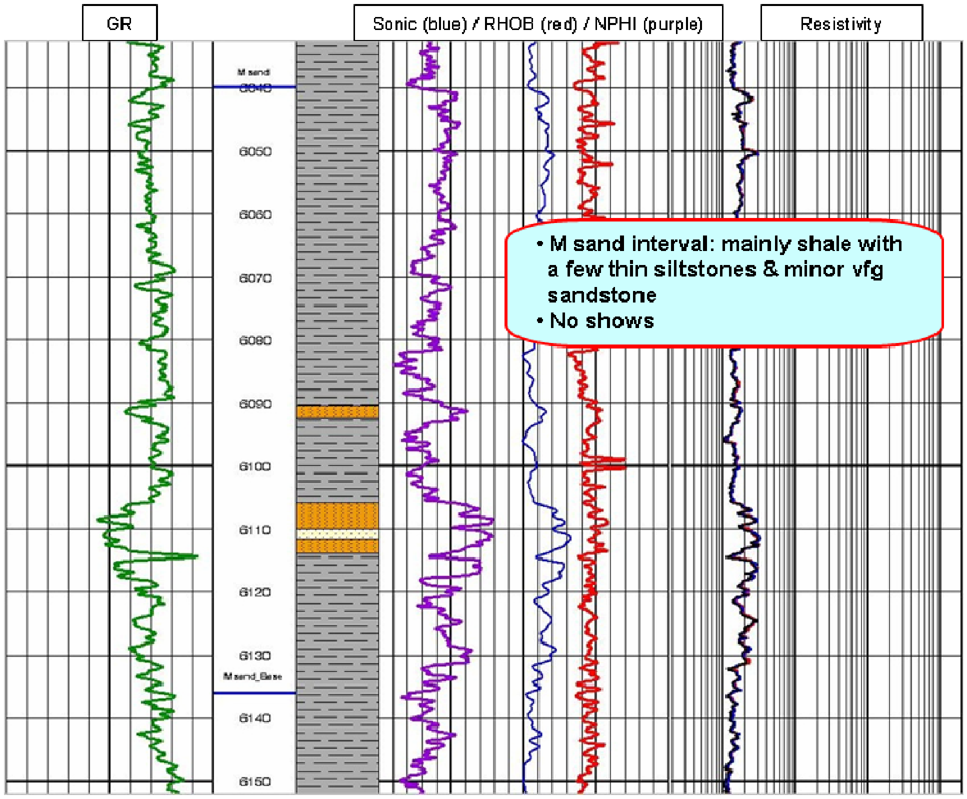


Figure 150. Crimson F-81: Well logs from the "M" sand interval (Late Hauterivian).

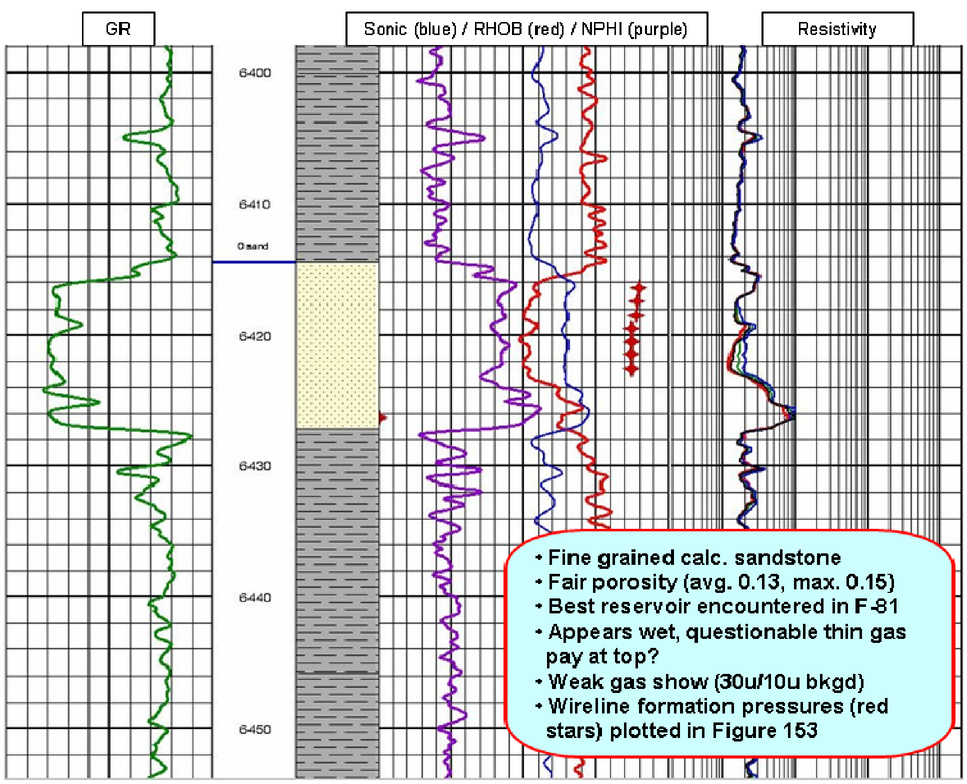


Figure 151. Crimson F-81: Well logs from the "O" sand interval (Hauterivian).

The only reservoir quality sand discovered in the Crimson well was the O Sand at 6414m MD in the Late Hauterivian upper Missisauga equivalent (Figure 151) (Marathon, 2005). The O Sand is 13m thick and consists of fine-grained calcareous sandstone with an average porosity of 13% (maximum porosity 15%). A weak mud-gas show of 30tgu/10u was detected during drilling and there was some increase in resistivity (up to 3 ohms) near the top of the sand that may indicate the presence of a thin ~1.5m thick gas pay zone. It should be noted that while the density log indicates that approximately 12% porosity is present at the top of the sand, the neutron and sonic logs suggest that porosity is decreasing over this interval. Due to the thinness of the apparent pay and the inconsistent log responses across the top of the zone, the presence of gas pay is considered questionable.

Nine MDT wireline formation pressures were attempted in the O Sand: two were dry tests (tight), three were supercharged and four had “valid” pressures (Figure 152). A straight line fit through a plot of these latter four pressures results in a gradient of 11.14 Kpa/m. This is a water gradient and supports the log interpretation that the sand is wet. No valid pressures were acquired at the top of the sand so it remains unclear if some modest gas pay is present at that elevation. Using indicators such as mud weight increases in response to rising connection and trip gas, and sonic and resistivity log trends, the top of overpressure was estimated to occur at approximately 3500m TVD.

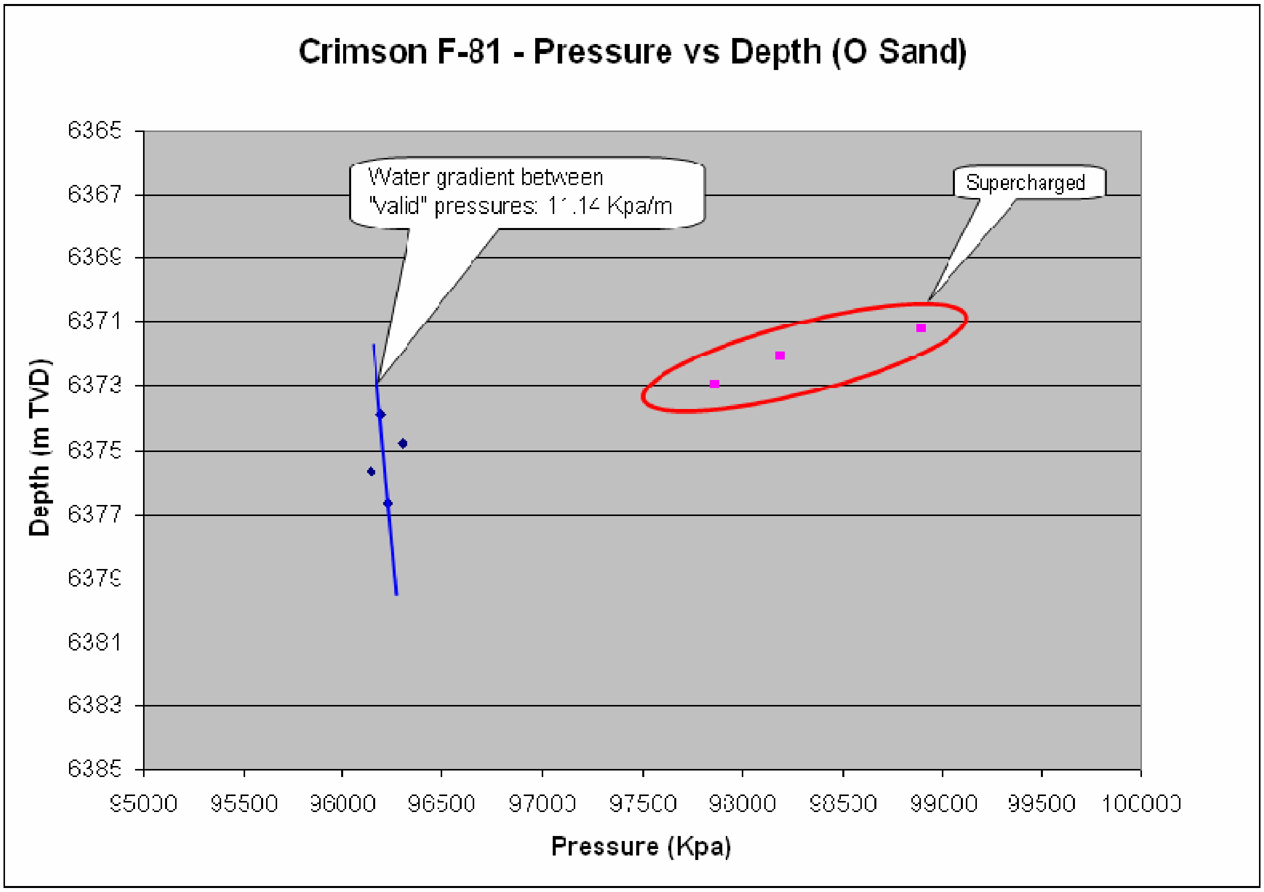


Figure 152. Pressure versus depth plot for Crimson F-81 “O” sand.

Seismic Interpretation

The regional setting and correlation between the Annapolis and Crimson wells is shown in Figure 90. A northwest- to southeast-trending 3D seismic dip section through the Crimson well illustrates the limited seismic response to the interpreted reservoir succession (Figure 153). Evidence of salt withdrawal is clearly seen to the southwest as are latest Cretaceous to Early Tertiary age normal faulting. However, while these faults sole into the base of the salt withdrawal mini-basin, strata adjacent to the faults show no evidence of growth. These crestal and bounding faults would not compromise the structure as thick overlying shales would provide adequate top seal (Figure 144).

Figure 145 details the Annapolis–Crimson conceptual model with the lowstand coastal /delta plain complex cut by fluvial channels feeding shoreline sands. This progresses to a shale-prone bypass zone and then to the deep water fairways fed by slope channel systems. Crimson's location at the end of a depositional fairway and in front of a salt backstop was viewed as a prime location to trap turbidite sands (Figure 146). This model has proved successful in the GOM, especially with well defined reservoir seismic attributes that increase the chance of success. Scotian Basin successions are older and as such these facies are difficult to image. The Crimson synthetic seismogram (Figure 154) illustrates this point, revealing a poor correlation with the seismic data in the lower section. A lower frequency display would possibly enhance definition of correlative horizons in this interval.

Biostratigraphy

Biostratigraphic analysis (Robertson Research, 2005) closely matches that for the nearby (9km) Marathon Annapolis B-24 and G-24 wells (Enclosures D, E). The thin Tertiary section was sampled starting in the Late Eocene (Priabonian) to Early Paleocene (Danian) within which is contained several modest breaks and hiatus. Most of the Late Cretaceous strata are missing through erosional events in the Late Paleocene, Late Campanian and Late Turonian. The Banquereau sediments rest unconformably on Middle Cenomanian silts and shales of the upper Logan Canyon formation, with the entire Dawson Canyon formation absent. The remaining Logan Canyon to lower Missisauga section is essentially uninterrupted except for a possible break in the Middle Aptian that is observed in Annapolis well.

Paleoenvironment

Paleobathymetric interpretation for the well indicates that given its more distal position relative to Annapolis, equivalent Crimson strata reveal upper slope paleoenvironments more common than the outer shelf. Remnant Wyandot and Eocene chalks and marls – both eroded and condensed – point to a well oxygenated outer shelf environment. Upper Logan Canyon sediments are also interpreted to have been deposited in an upper slope setting. Conformable underlying lower Logan Canyon (late Albian) to late upper Missisauga (Early Barremian) strata are interpreted to have been laid down on an outer shelf to upper slope paleoenvironment. The deeper middle Missisauga (Hauterivian) sequence reflects deposition in an outer shelf position.

Geochemistry

Organic matter in Crimson F-81 sediments are mostly (95%) Type **III** woody/herbaceous organic matter (Table 11). Exceptions are within the Tertiary and Latest Cretaceous, where approximately 3% is Type **I** amorphous and alginate 15% Type **I/II** liptinite / exinite. All sediments have a gas-prone kerogen assembly. TOCs range from 0.5% to 2+% with the richest source rocks (~2.5) found in the Early Albian age Logan Canyon formation (Cree member).

The Tertiary was sampled in only two locations – the top of the sampled section and above the Paleocene unconformity – and reveals a marginally to moderately mature sequence. Beneath the three unconformities noted above, the Late Cretaceous Logan Canyon to Early Cretaceous upper Missisauga formations are all mature and within the peak oil generating window. Lower Missisauga sediments within the basal 400m of the well are all in the late mature phase.

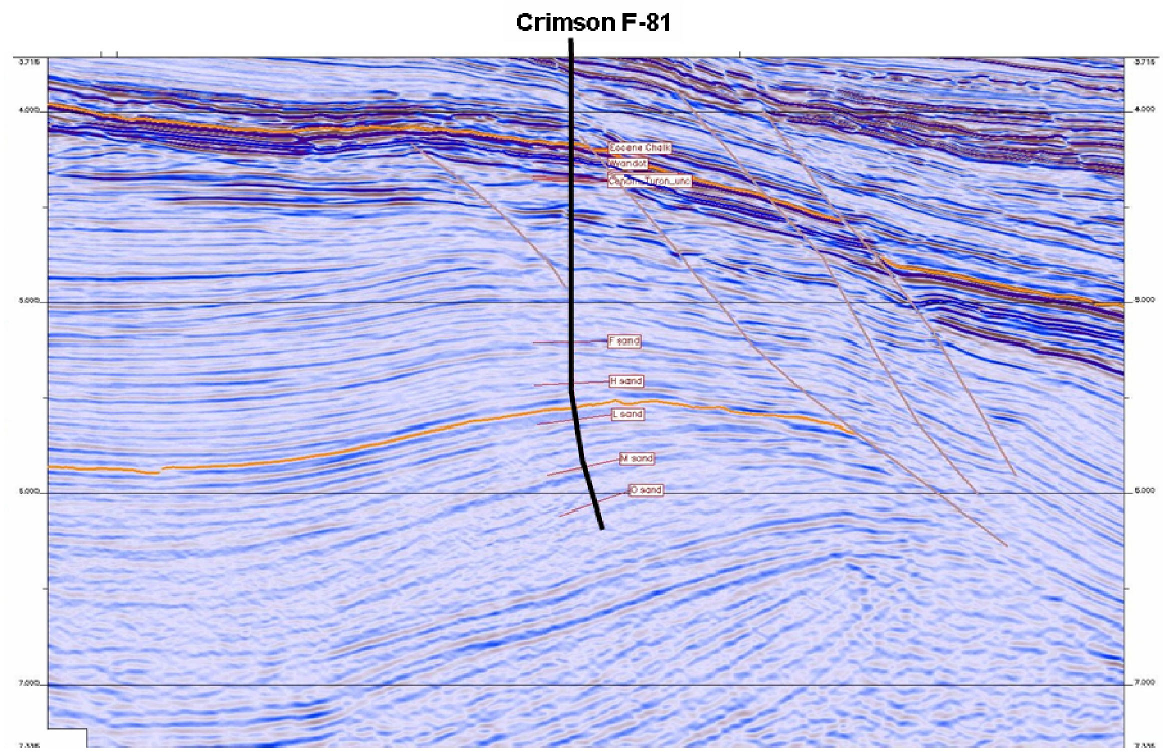


Figure 153. Detailed profile of the Crimson structure, zoomed in on the target interval. Data courtesy of CGG-VERITAS.

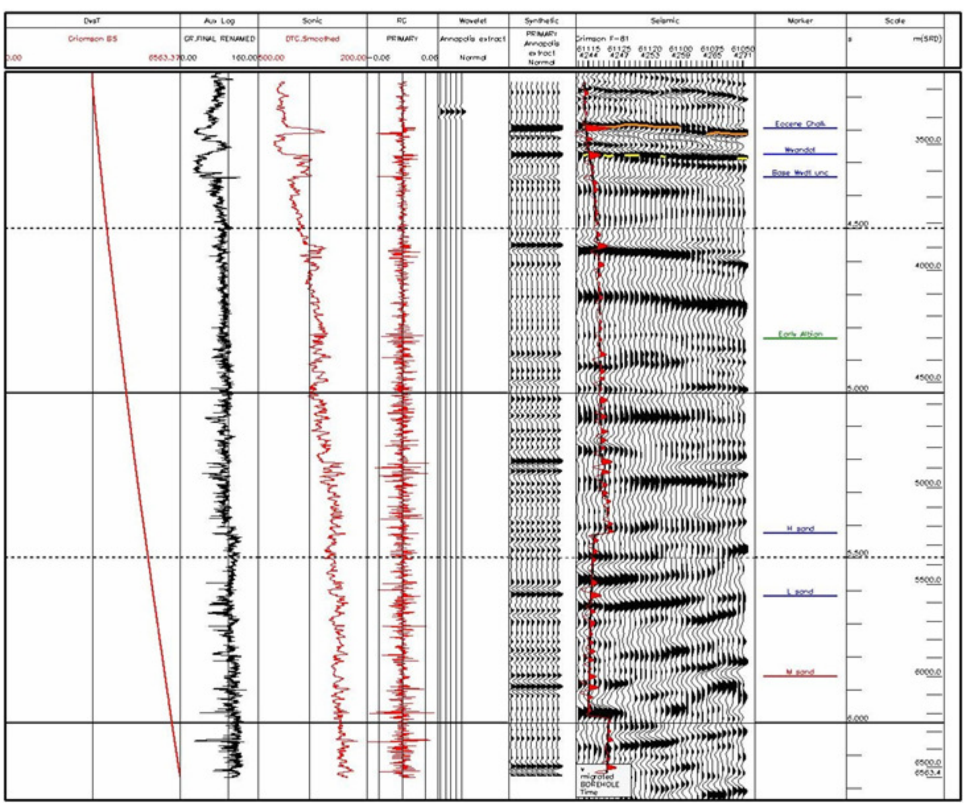


Figure 154. Crimson F-81: Synthetic Seismic.

Depth (m)	Formation	Age	Vitrinite Reflection (% Ro)	Kerogen Type	Maturity for oil generation
2092	Sea Floor	Recent	n/a	n/a	n/a
3300	Banquereau	L. Eocene (Priabonian)	~ 0.42	(I/II)-III	marginally mature
3580	Banquereau	E. Paleocene (Danian)	~ 0.55	(II)-III	moderately mature
3690 - 6300	U. Logan Canyon to U. Missisauga	M. to L. Cretaceous (M. Cenomanian to L. Hauterivian)	~ 0.61 – 0.67	(II)-III	mature
6400 - 6670	Upper to Lower Missisauga	E. Cretaceous (L. to E. Hauterivian)	0.92 – 0.96	(II)-III	late mature

Table 11. Thermal maturation levels and kerogen types for the Crimson F-81 well (Core Lab, 2005). Ro values are means and the range for the respective interval.

Exploration Implications

The initial conclusion for the lack of sands at Crimson was an inefficient lowstand feeder system that failed to transport sand to the slope in front of the Sable paleodelta. However, such complexes have yet to be imaged beneath the modern shelf break. Furthermore, the deconstruction of the present-day salt-modified structural regime remains very difficult, and the prediction of a paleobathymetric low or mini-basin therefore is uncertain. Seismic mapping through a structure and conversion to depth involves several phases of interpretation, none of which are unique. Once again, the inability of seismic to identify and define reservoir intervals was the major challenge.

Having drilled Crimson in the same interpreted mini-basin complex as Annapolis, the operator must be commended for carrying out an intensive effort to track down the elusive fan system. But as previously expressed, similar multi-well efforts with better seismic resolution are required for future exploration.

5.10.3 Well Operations

Compared to other deepwater wells, F-81 experienced relatively minor operational difficulties losing a total of only 13.6 days (Figure 155) (Marathon, 2005). The most significant operational delays were as 4.4 days lost due to lost circulation and a subsequent cement squeeze, 2.2 days lost due to the failure of the near bit reamer, 1.5 days lost due to bit problems, and 0.9 days lost due to an unexpected discharge of drilling mud at the seafloor caused by the failure of the flex joint just above the BOP. Despite these problems, F-81 was drilled in 95.2 days, 0.8 days faster than the planned 96 AFE days. Considering Crimson F-81 was drilled in nearly 2100m of water to a TD of 6676m MD, and with access to previous well data, this operation clearly demonstrates that deepwater wells can be drilled successfully offshore Nova Scotia as originally budgeted.

5.10.4 Risk and Assessment

Crimson, like Annapolis, lies within the Central Upper Slope (Play #11) of the Board's 2002 assessment. The play adequacy was 64% and consisted of:

- Source 100%
- Reservoir 80%
- Trap 80%

The prospect adequacy was 25% for an overall adequacy of 16% or 1:6. The results of the well indicated that the reservoir input parameters were too optimistic. At the play level, the reservoir adequacy, which includes the ability to detect reservoir, was reduced from 80% to 50% (see Section 7.2). At the prospect level, the net pay thickness and the drilling success ratio were also reduced.

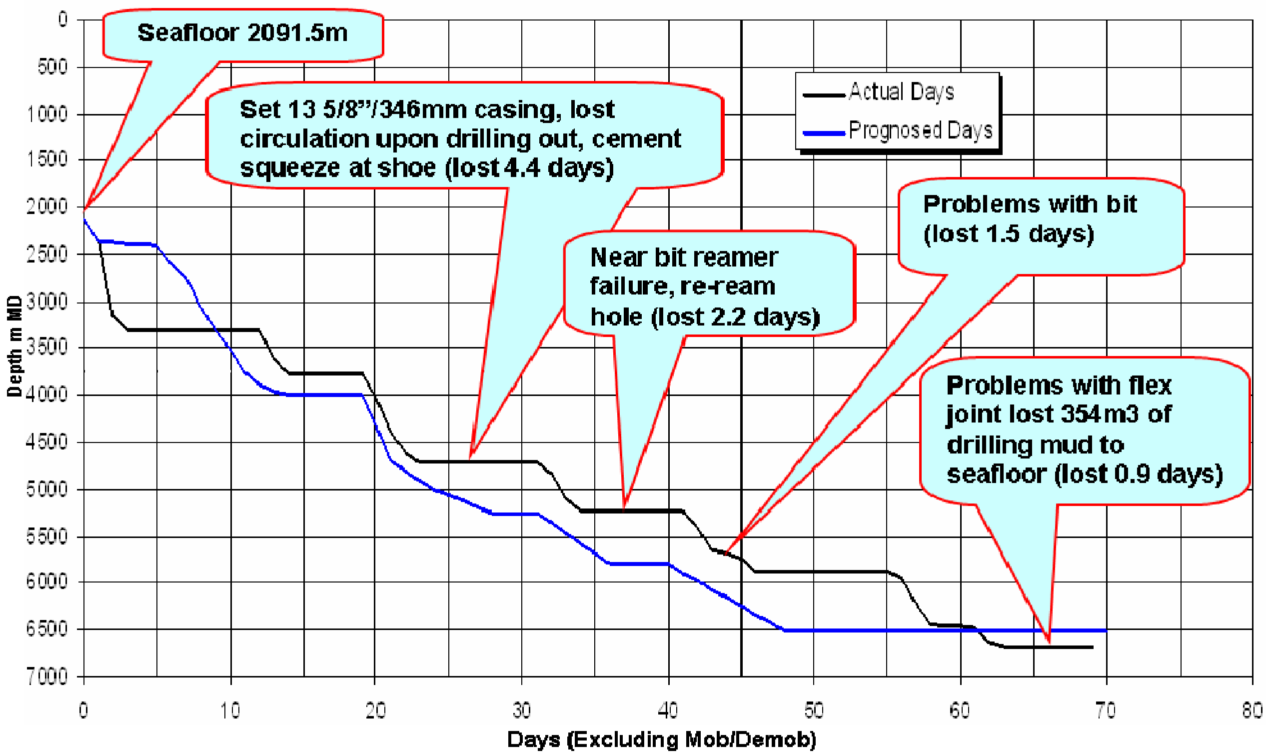


Figure 155. Drilling curve for Crimson F-81 (AFE and actual).

5.11 Deepwater Well Operational Summary

Authorization for Expenditure (AFE) Days versus Actual Days costs for the recent deepwater wells are presented in Figure 156. Both the Newburn H-23 and Crimson F-81 wells were completed under budget. Newburn's drilling rates were faster than anticipated, the stratigraphic tops came in higher, and the eventual TD was in turn 330m shallower than planned. Crimson was completed just slightly ahead of schedule (0.8 days early) as the total number of days lost due to operational problems (i.e. non-productive time) was very similar to the pre-spud estimate.

The remaining five wells – Annapolis B-24, Annapolis G-24, Torbrook C-15, Balvenie B-79 and Weymouth A-45 – took longer than planned for a variety of operational reasons as detailed in the preceding pages. Nevertheless, this has to be expected given that all these wells were drilled in a virtually undrilled deep water frontier basin to test new play concepts, penetrate unknown stratigraphic successions, and drill to depths greater than that of the four earlier wells completed at the margin edge decades before. The new knowledge gained from these bold wildcat wells will well serve those planning future exploration efforts in this basin.

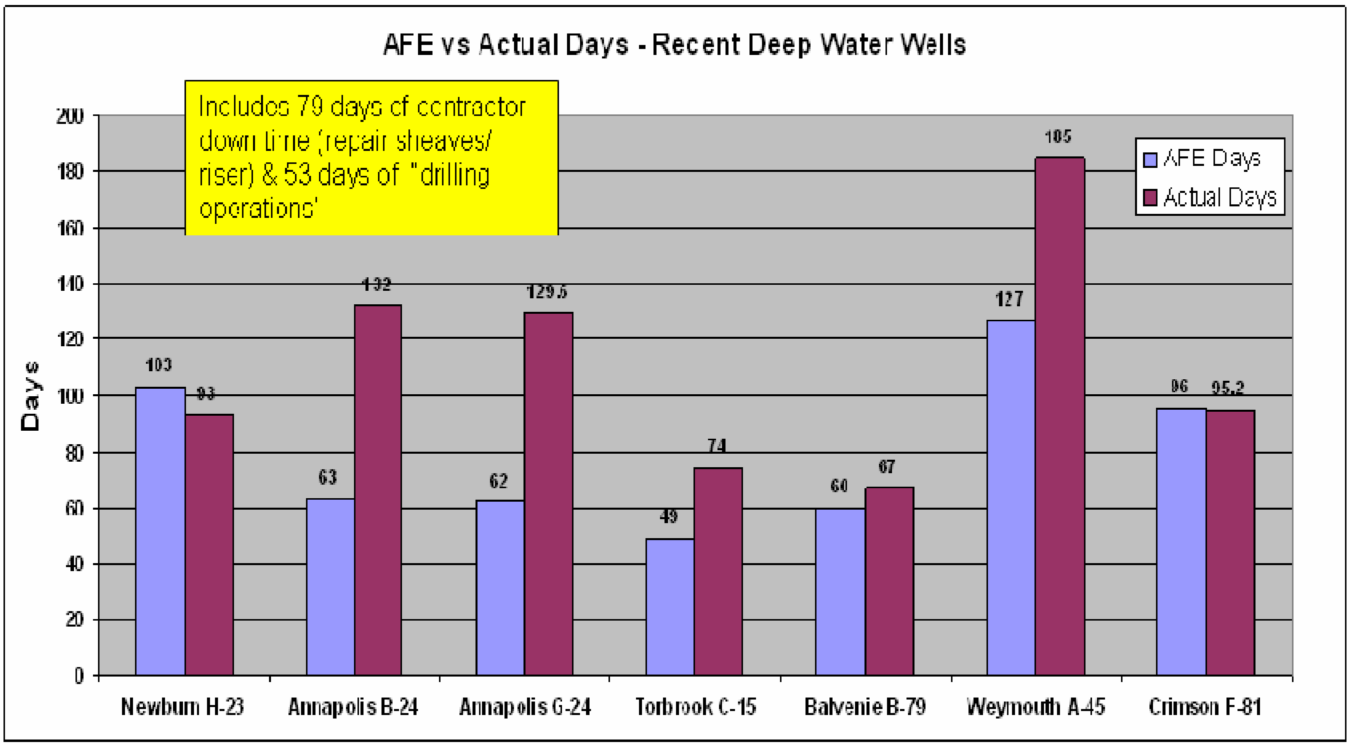


Figure 156. AFE versus actual days for recent deepwater wells.

6. SCOTIAN BASIN EXAMPLES OF DEEPWATER DEPOSITIONAL PROCESSES

6.1 Modern Environment

The current Holocene water bottom surface is always the most accurate map (Figure 2). The surficial geology on the Scotian Shelf shows that it is blanketed by large tracts of glacially-derived sediments, and are underlain by the seaward-prograding wedge of Jurassic, Cretaceous and Tertiary aged sediments. The bathymetry of the Scotian Slope reveals the eastern shelf margin incised with canyons, with fewer and/or in-filled channels along the western part (Figure 157). The major canyon systems extend from inboard of the shelf break out onto the floor of the abyssal plain. The Gully is an excellent example of a large scale large submarine canyon. It is about 200km southeast of the Nova Scotia coast and 55km east of Sable Island. It can be traced about 70km into the shelf, making it larger than any other submarine canyon off eastern North America.

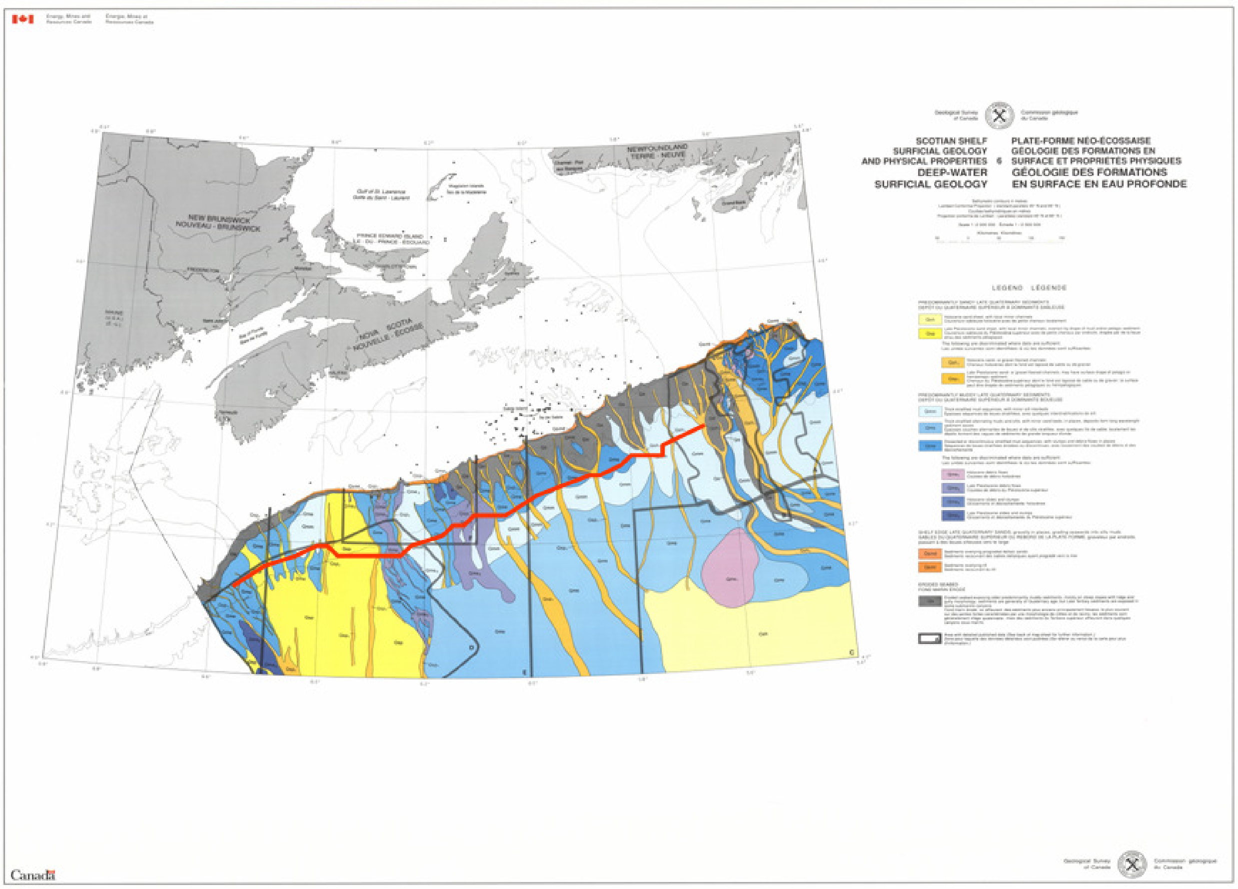


Figure 157. Present-day deep-water surficial geology of the deep-water, offshore Nova Scotia (AGC, 1991). The leading edge of the subsurface salt is shown in red.

6.2 The Grand Banks Earthquake of 1929

In 1929, a 7.2 magnitude earthquake was recorded with an epicentre at the mouth of the Laurentian Channel. The earthquake caused the sequential breaking of numerous trans-Atlantic telephone cables crossing the Laurentian Fan. Those nearest the quake broke immediately while those farther away broke with ever-increasing time delays. This was very puzzling to the scientists of the day and it was not until 25 years later with better seafloor mapping techniques did they realize there were large underwater landslides and vast amounts of sediments were carried large distances (Figure 158). The sequential cable breaks were finally understood which indicated surprising velocities up to 25m/s (90km/hr) (Figure 159).

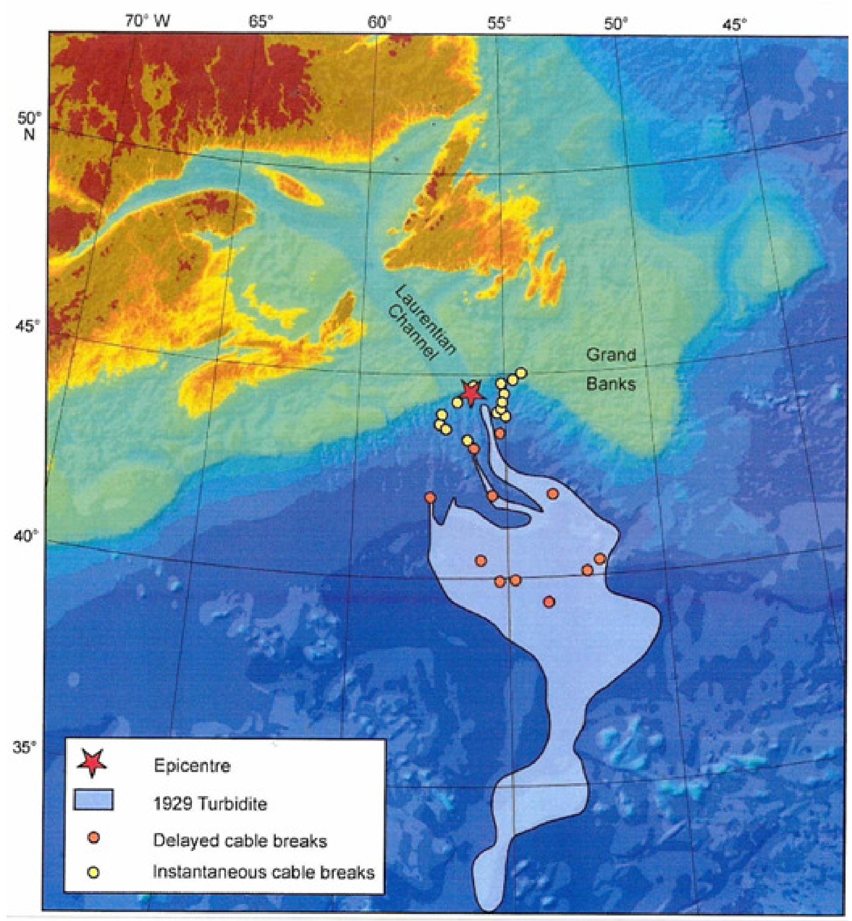


Figure 158. Map showing the extent of turbidite deposition from the 1929 earthquake and turbidite flow at the mouth of the Laurentian Channel (Atlantic Geoscience Society, 2001).

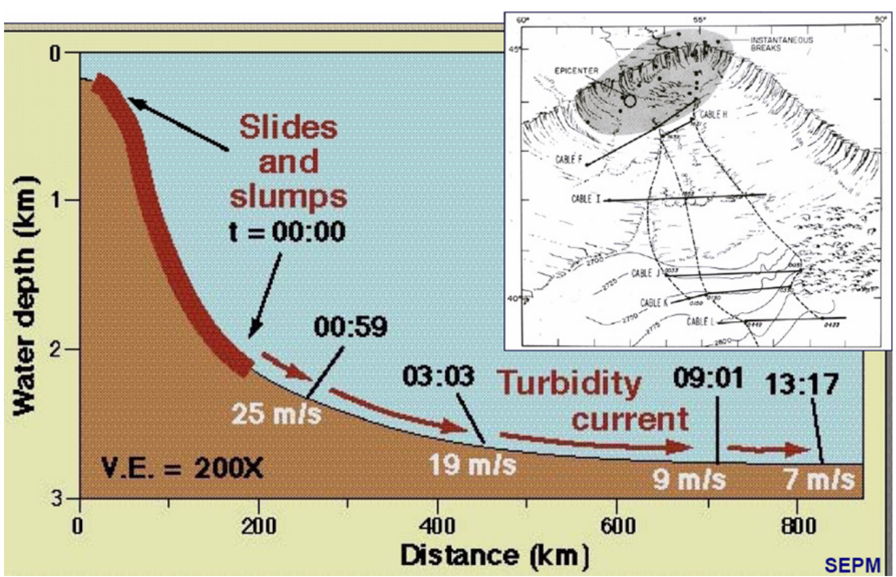


Figure 159. Schematic showing velocity versus water depth of the 1929 turbidity current (Martinsen, 2003).

6.3 Mega-Slumps

An excellent example of a Miocene slump is shown on a TGS 2D line located near the Shelburne well in about 1000 m of water (Figure 160). It exhibits the classic up-dip extension, massive block sliding and down-dip compression with toe-thrusts reaching up to the seafloor. The initial slide detachment surface within the slope strata is about 15km long. The limit of this failed section is the down slope edge of the large depression on the "Base of Slump" map shown in Figure 161. This 50km wide mobile mass then continued to move down slope along the seafloor as evidenced by a thin chaotic interval on the seismic extending seaward for another 80km. Such mass-wasting processes are probably ubiquitous along the margin and throughout geologic time. The Torbrook anomaly is another example of an older buried slump (Figure 112).

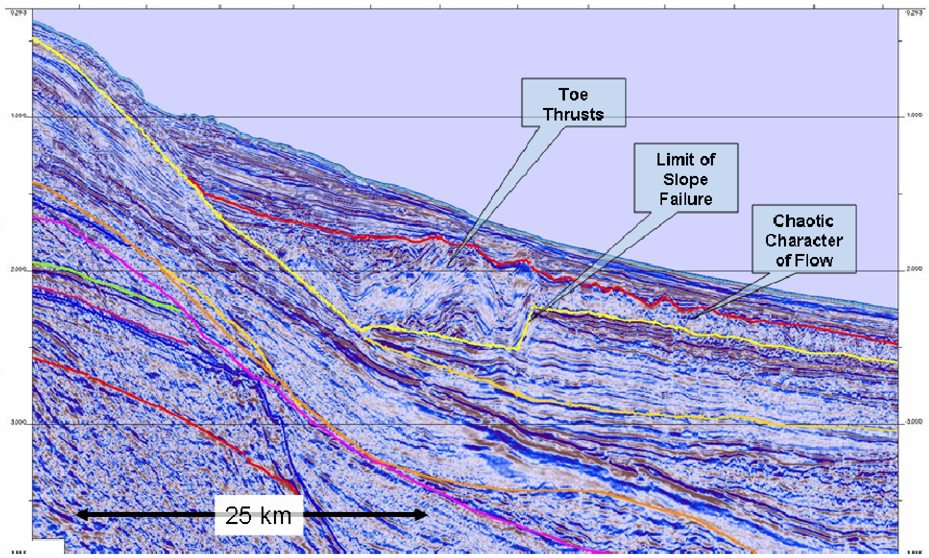


Figure 160. 2-D Seismic example of a slope mega-slump in the late Tertiary. Data courtesy of TGS-NOPEC.

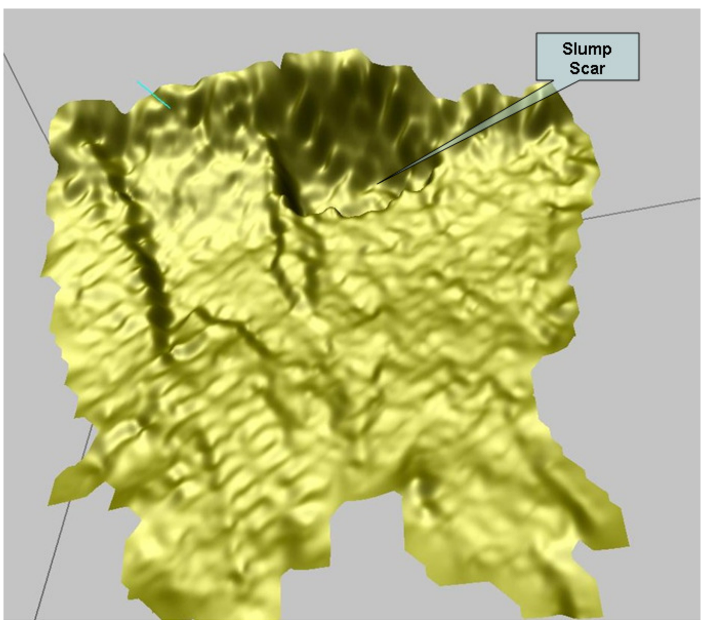


Figure 161. 3-D surface of the mega-slump shown in Figure 162.

6.4 Canyon-Fan Complexes

While the recent deep water wells all drilled current positive relief anticlinal structures, their origins were interpreted to have once been topographic low depocentres receptive to turbidite sands. It is thus instructive to identify and describe unequivocal examples of original depocentres in stratigraphic successions on the Scotian Slope.

Figure 162 is a seismic cross section of a Late Tertiary channel and fill complex, with Figure 163 displaying the map view of this feature. The channel is at least 130km long and continues past the extent of the seismic coverage. There are many similar channels along the Scotian Slope.

The search for the important Cretaceous age feeder channels is much more difficult, especially when located under the modern slope and shelf/slope break. Both areas are very heavily incised causing seismic data quality degradation with depth. The Base Tertiary unconformity has removed large amounts of the Cretaceous strata in this area, and its heavily channeled surface also causes problems with data quality (Figure 164). These factors have therefore made it very difficult to map any Cretaceous sand delivery systems along the slope.

Nevertheless, where bottom conditions and sediment cover permit, examples of Cretaceous channels are occasionally observed in seismic profiles (Figures 165 & 166). This is a very wide channel and is located seaward of the salt diaper zone in southwest part of the Scotian Slope. This channel character cannot be correlated up dip because of the extensive salt diapirism present, and so the up-dip path of the channel must be inferred incorporating the distribution of diapirs and related features. While this area is the only one where the TGS deep water regional survey extends out beyond the depositional edge of the salt, the channel's presence suggests that additional Cretaceous channels may exist beyond the limits of the data set in this and other regions.

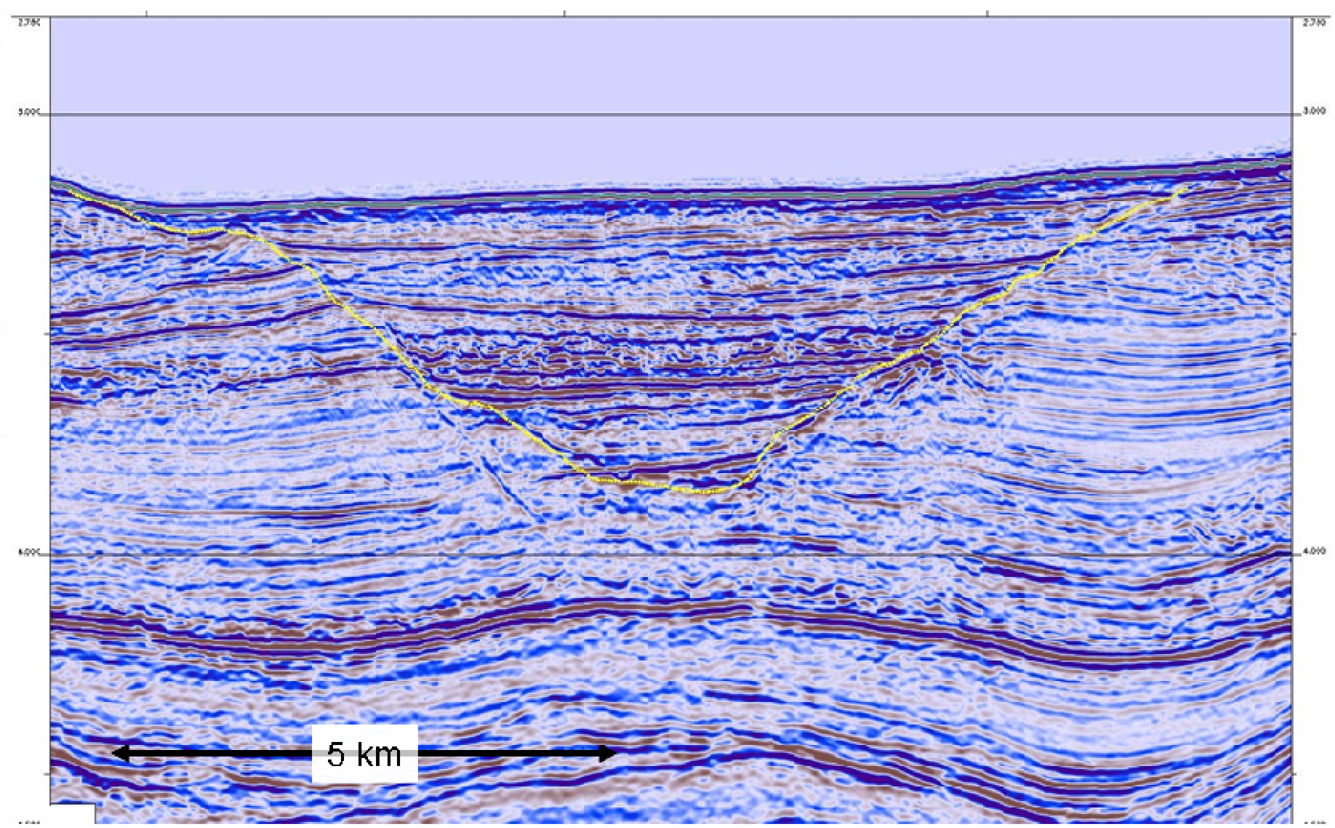


Figure 162. 2-D seismic example of a late Tertiary channel on the slope, shown in the strike direction. Data courtesy of TGS-NOPEC.

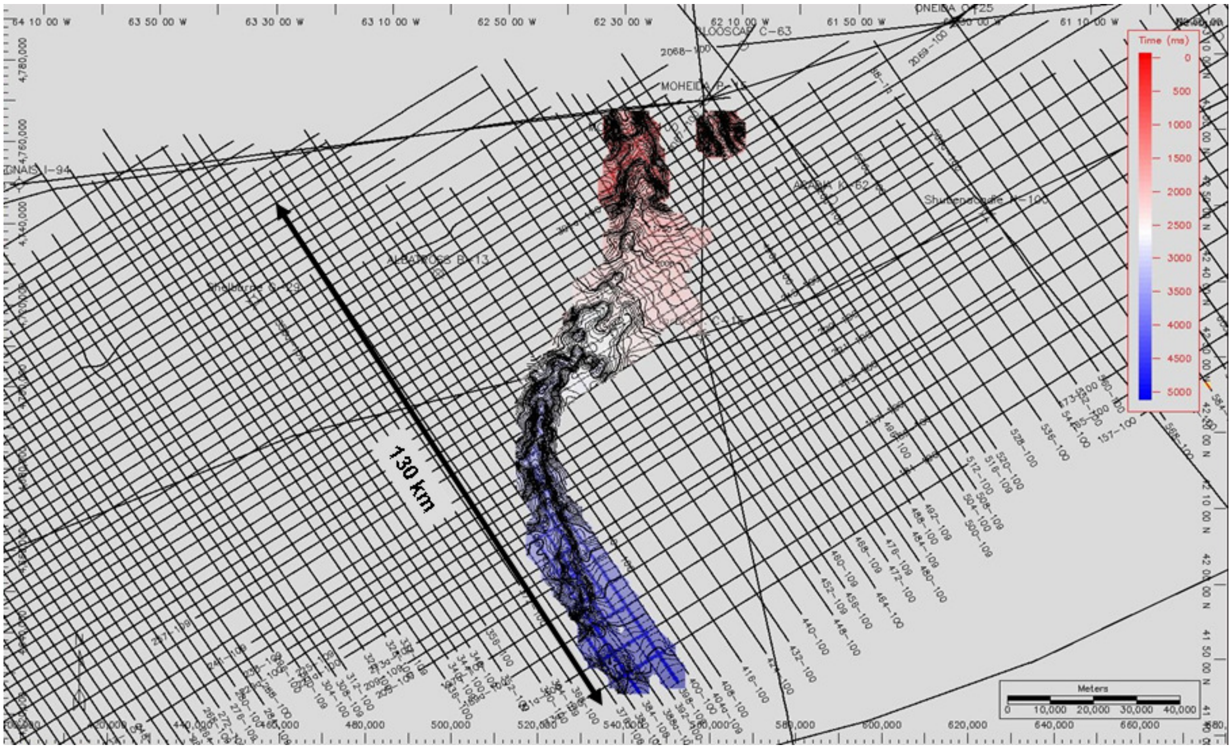


Figure 163. Map view of the late Tertiary channel shown in Figure 162.

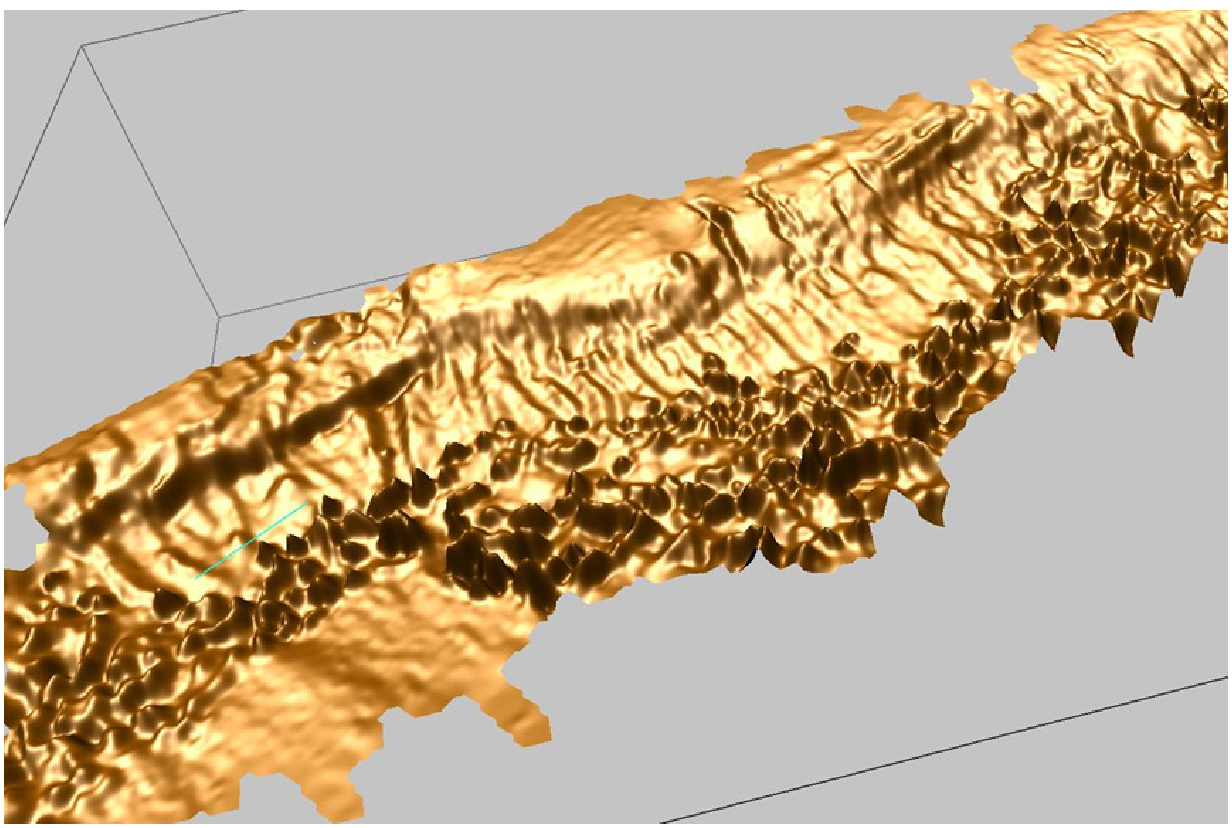


Figure 164. 3-D rendition of the Base Tertiary surface in the deep-water.

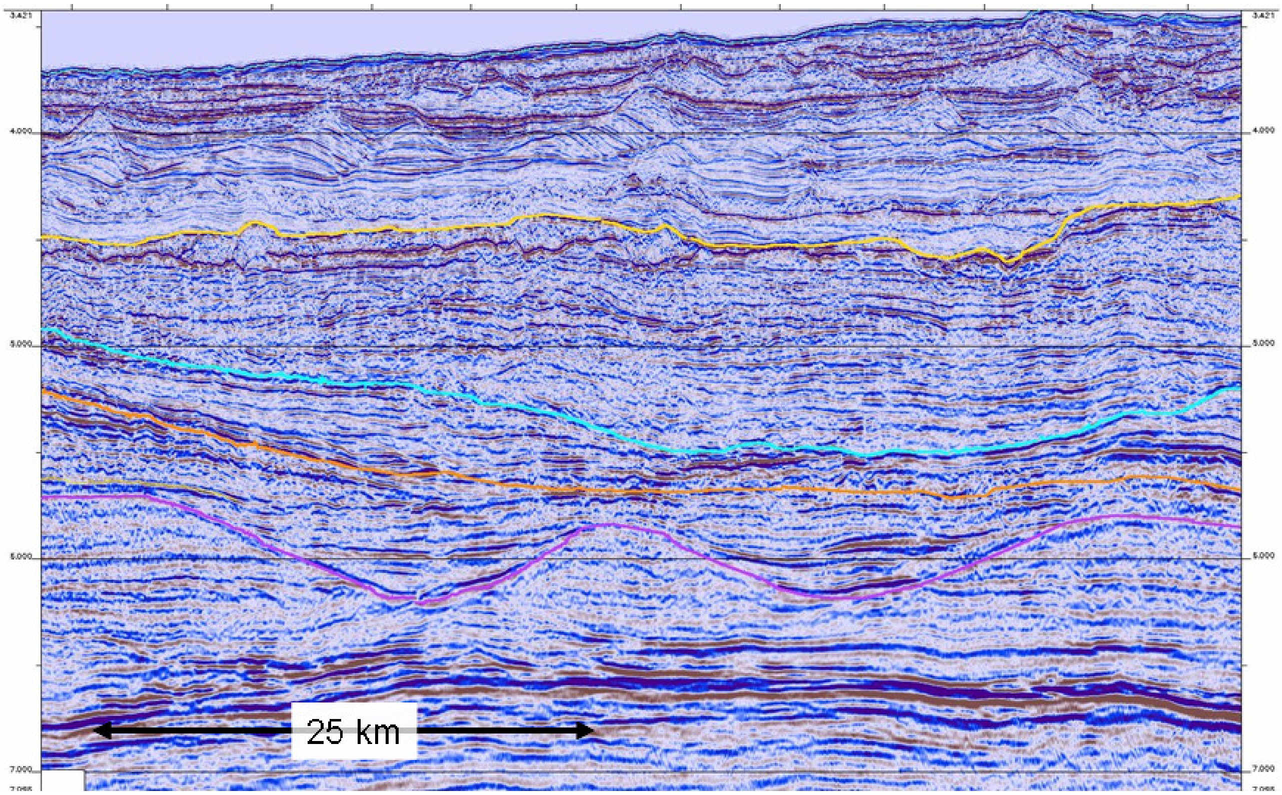


Figure 165. 2-D seismic example of Cretaceous channels on the slope (purple horizon). Data courtesy of TGS-NOPEC.

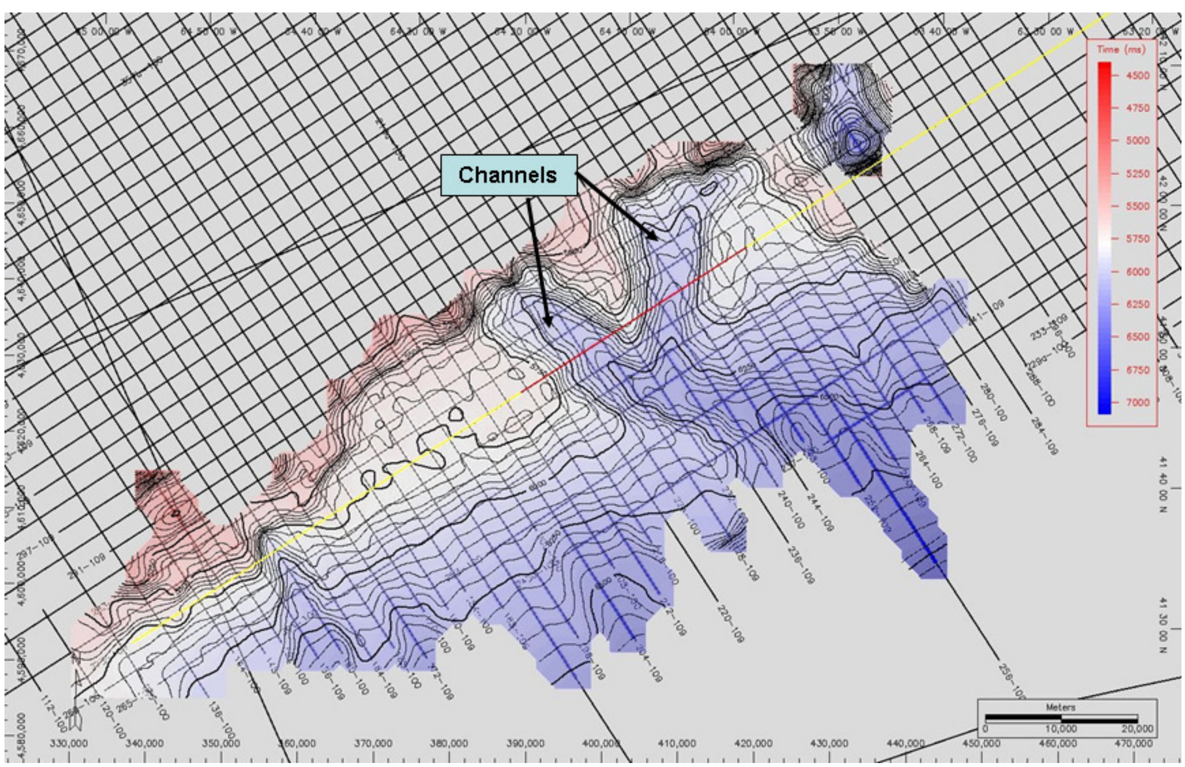


Figure 166. Map view of the Cretaceous channels shown in Figure 165.

6.5 Mini-Basins

The main salt diapiric and canopy areas (Figures 1 & 34) contain a large number of Jurassic to Tertiary age mini-basins. An excellent example of a Cretaceous-Tertiary mini-basin is presented in Figure 167 illustrates a good example of an undeformed depocentre. The facies and lithologies contained in this example and indeed all others remain unknown as an unequivocal depocentre has yet been drilled in the Scotian Basin.

6.6 Structured Mini-Basins

The mini-basin shown in Figure 167 is a classic example of the product of salt deflation and related sedimentation. When adjacent salt bodies continue to deflate, the flanks of the mini-basin collapse and the depocentre low's central synclinal axis becoming an anticlinal high. This process is known as inversion and is quite common in salt-prone areas with the resultant features informally known as "turtles" reflecting their morphologies. These structures are excellent trapping configurations, with Figure 168 illustrating a superb Nova Scotia example. This structure is imaged on a 2D regional seismic survey and would require 3D seismic to properly delineate the feature.

Figure 169 is another single line Nova Scotia example of a Cretaceous age structured mini-basin with the appearance of a small turtle. In this case however, there could be a wrenching component to its evolution where compression caused the uplift. Should a reservoir facies exist within the succession, it would be an attractive target.

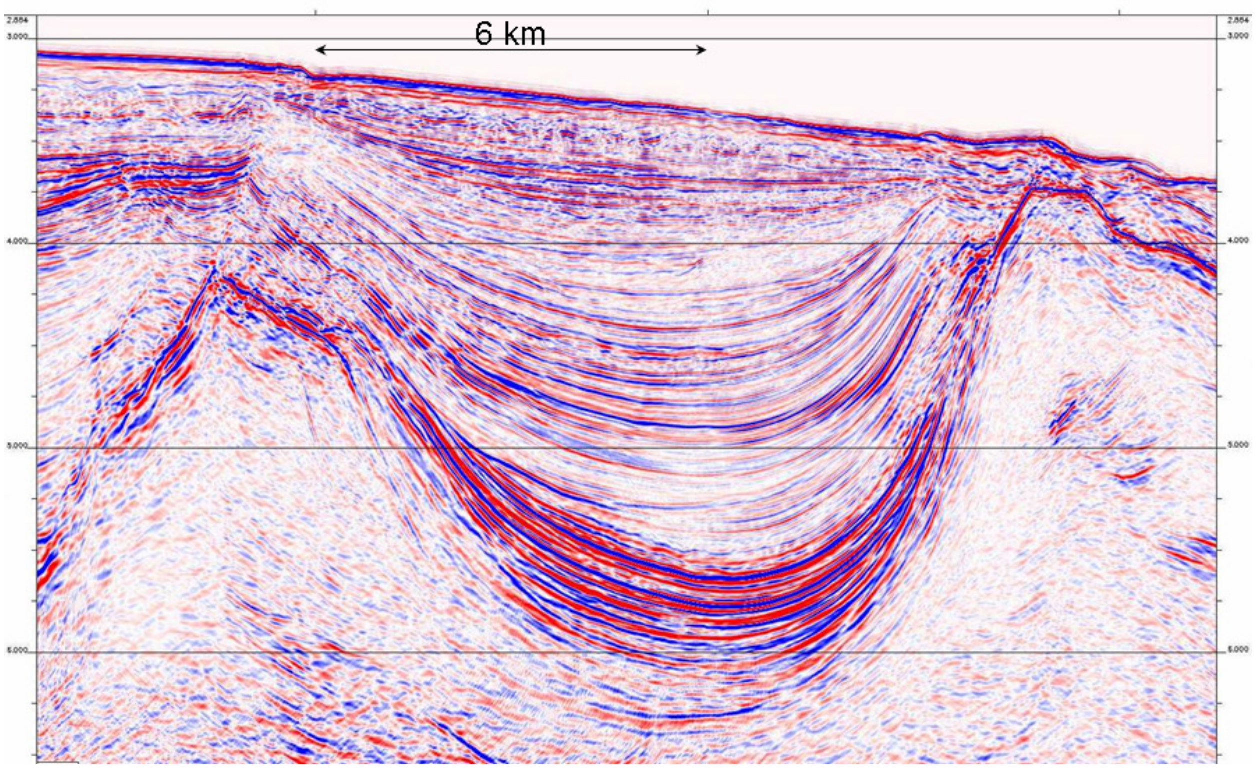


Figure 167. 2-D seismic example of Cretaceous-Tertiary minibasin, from the central canopy complex (area 2 - Figure 1). Data courtesy of TGS-NOPEC.

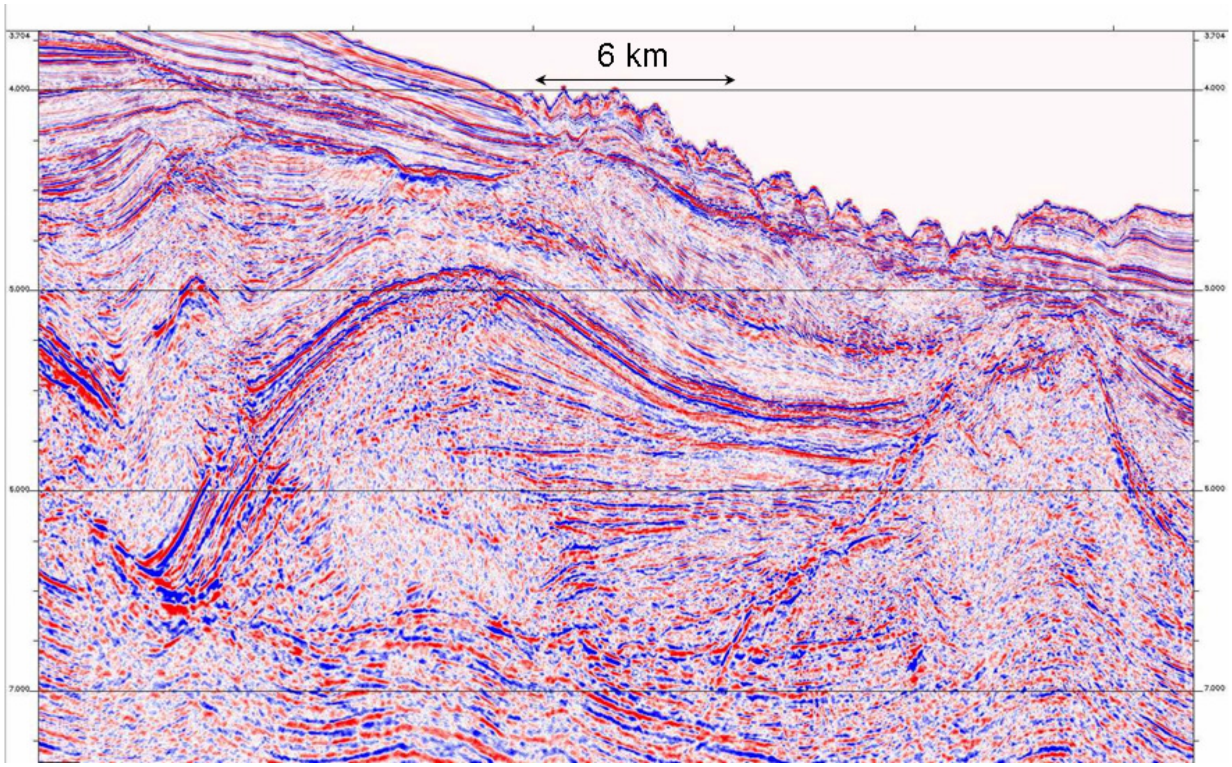


Figure 168. 2-D seismic example of a large ‘turtle’ structure, from the central canopy complex (area 2 - Figure 1). Data courtesy of TGS-NOPEC.

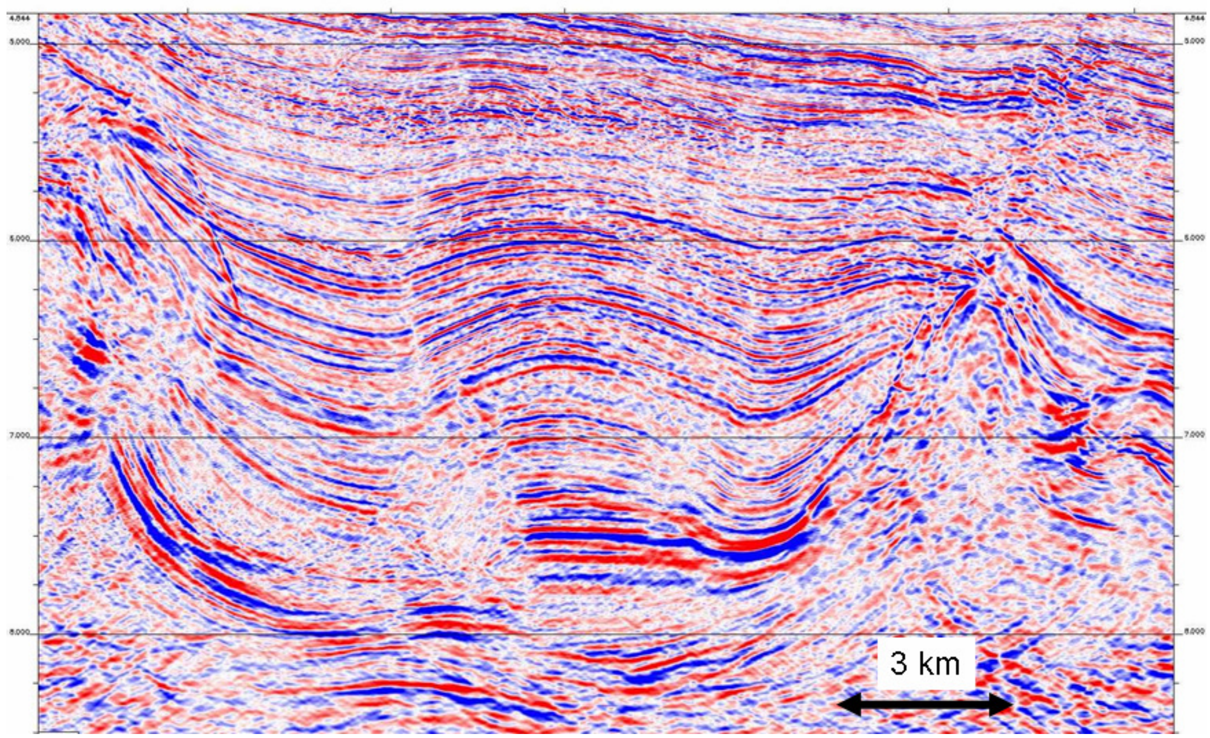


Figure 169. 2-D seismic example of an inverted minibasin, from the salt diapir zone (area 1 - Figure 1). Data courtesy of TGS-NOPEC.

Figure 170 is a similar age example but with very slight structuring. Here, there is evidence of an apparent convex-shaped depositional buildup with some internal architectures suggestive of a basin floor channel complex or fan-like feature.

6.7 Other Features

Figure 171 is from the Salt Withdrawal area with evidence of the underlying interpreted deep water Early to Middle Jurassic post-rift section. The isolated salt diapirs are the result of Late Jurassic siliciclastic progradation and large scale salt deflation. Several remnant salt rollers can be seen between the diapirs. Sand-prone turbidites could pond in and around these rollers.

In the southwest part of the Scotian Slope, the TGS regional seismic program extends out beyond the allochthonous salt edge. Figure 172 illustrates the edge of a salt thrust sheet with a possible subsalt play, as well as potential suprasalt traps incorporating Jurassic and Cretaceous sediments. A superb example of structures common from the same region is seen in Figure 173 that includes a complex of mini-basin floors and flanks, salt crests, subsalt features, etc.

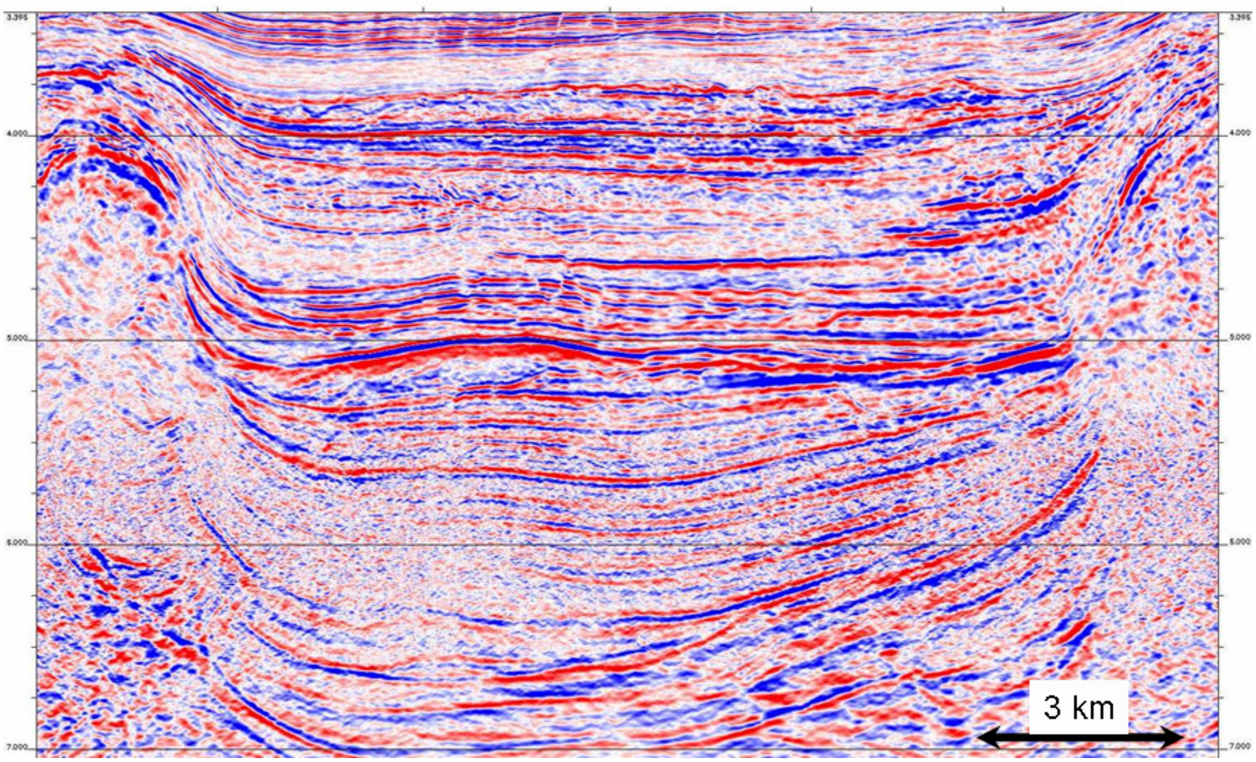


Figure 170. 2-D seismic example of a subtle turtle structure, from the main salt diapir zone (area 1 - Figure 1). Data courtesy of TGS-NOPEC.

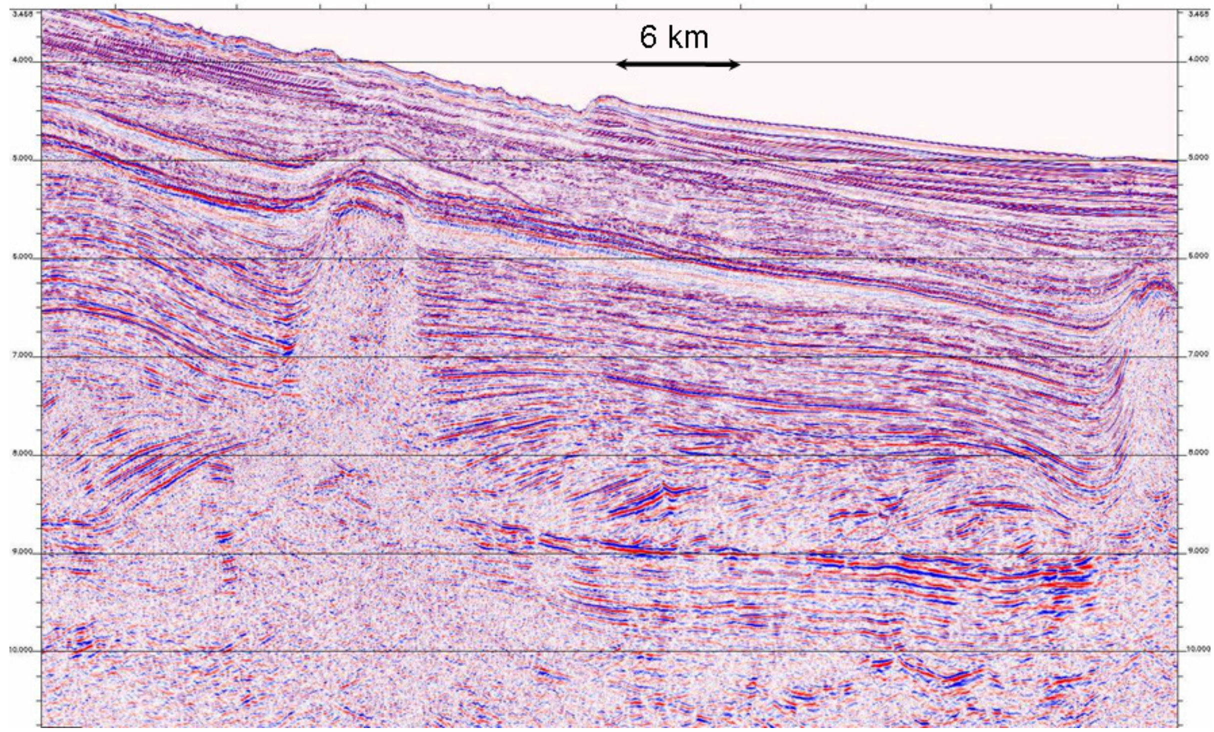


Figure 171. 2-D seismic example of salt rollers, from the salt withdrawl area (area 3 - Figure 1). Data courtesy of TGS-NOPEC.

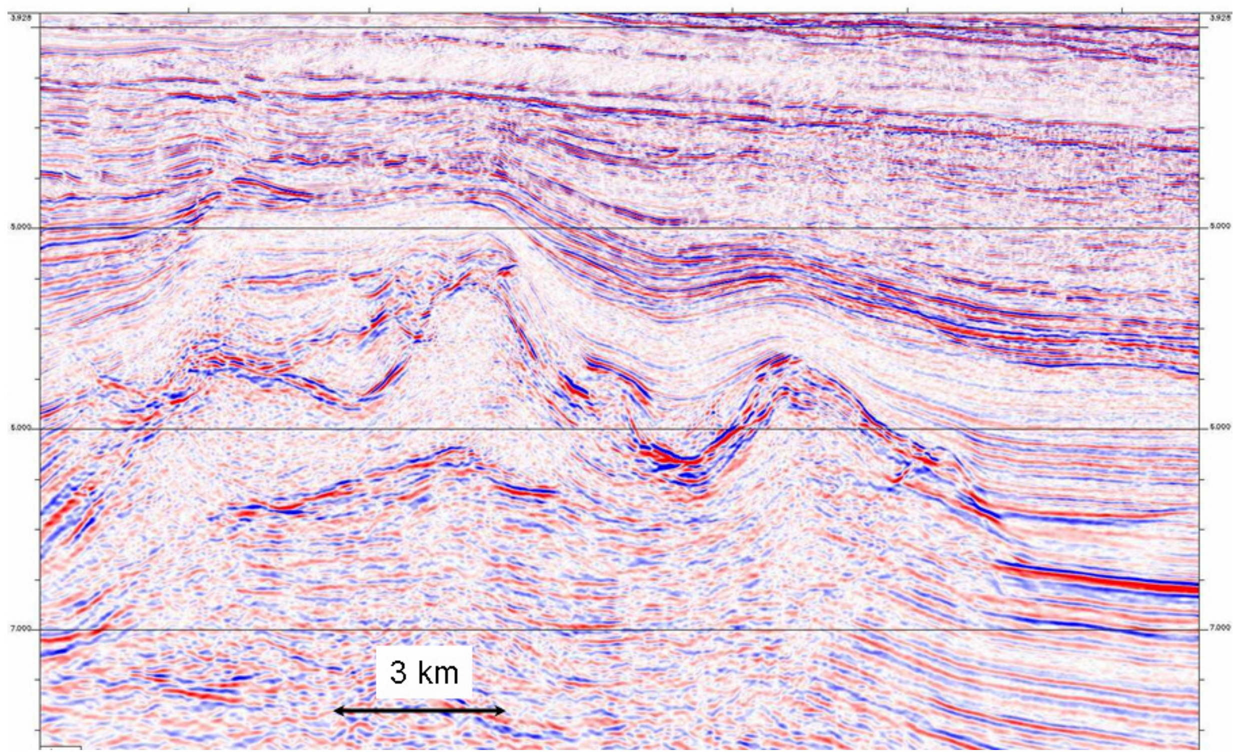


Figure 174. 2-D seismic example of the Jurassic subsalt play in the salt diapir zone (area 1 - Figure 1). Data courtesy of TGS-NOPEC.

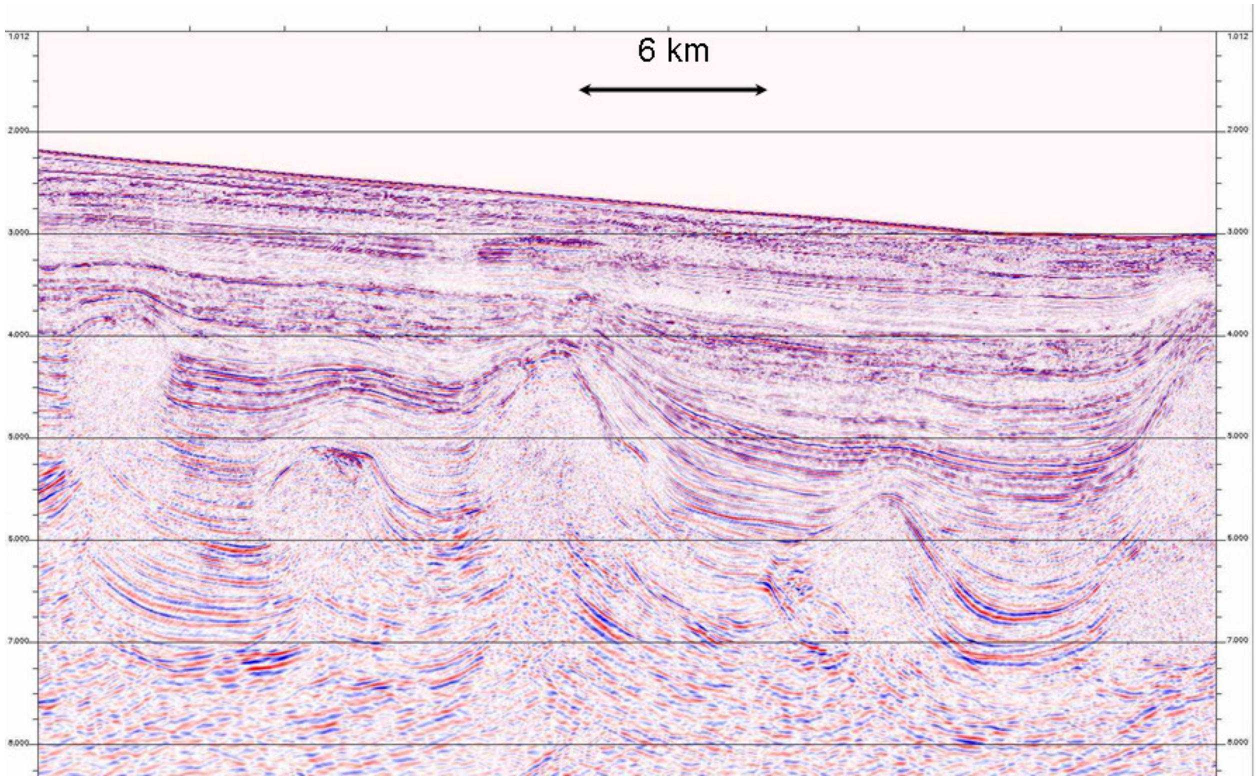


Figure 175. 2-D seismic example of several minibasin floor, flank, and salt crest plays in the main salt diapir zone (area 1 – Figure 1). Data courtesy of TGS-NOPEC.

7. IMPACT ON 2002 DEEPWATER ASSESSMENT

Prior to addressing the revision to the 2002 assessment, a brief overview of the original work is required. Although the recent wells were few in number (seven), their results did warrant changes in the play and prospect level assumptions.

7.1 Overview of the 2002 Assessment

The 2002 assessment (Kidston et al., 2002) consisted of two major components: a basin evaluation and a numerical assessment. The evaluation was completed prior to completion of the Annapolis and subsequent wells, although knowledge was available of gas kick near base Tertiary in the first of the modern wells (Annapolis B-24).

The deepwater Scotian Slope had recently been covered by an extensive 2D seismic program by TGS-NOPEC (1998-1999) and 30,000km of this data was interpreted in-house. This was original work by the Board and the data quality enabled a new visualization of the subsurface. The number of allochthonous salt bodies and the structural deformation of the Jurassic to Tertiary succession gave rise to a new appreciation of the challenges that lay ahead for both the explorer and the regulator. As a result of the seismic interpretation, the slope was divided into six play areas based on major changes in the structural regime and salt features (Figure 174):

1. Main Salt Diapir Zone
2. Central Canopy Salt Complex
3. Salt Withdrawal Area
4. Northeast Salt Canopy/Diapir Complex
5. Central Upper Slope
6. Western Upper Slope

Twelve major play types were observed in the deepwater offshore as shown schematically in Figure 175. In each of the six play areas, the dominant play types were selected for numerical analysis that resulted in twelve assessment runs (Table 12). Not all play types were present in each of the zones.

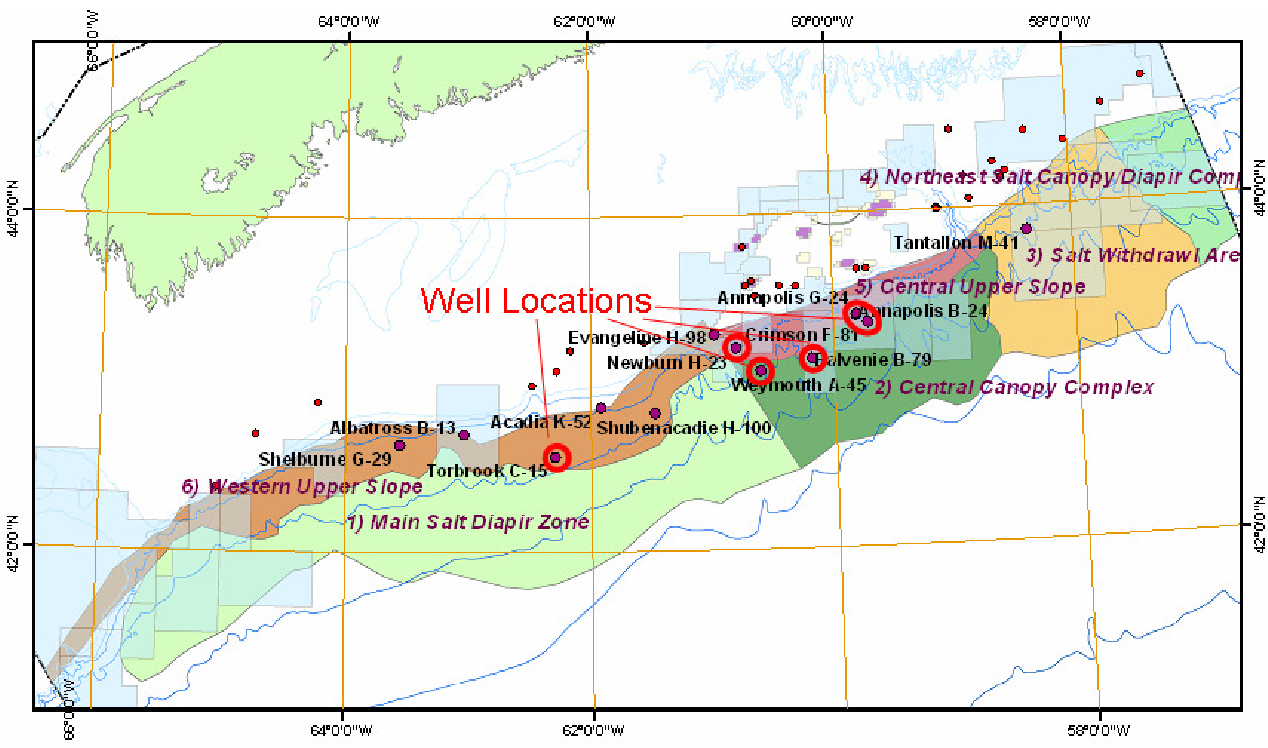


Figure 174. Deep-water map showing the subsurface geologic zones. The plays recalculated after recent drilling are restricted to zones 2, 5, and 6, as they are the only zones with recent wells (red circles).

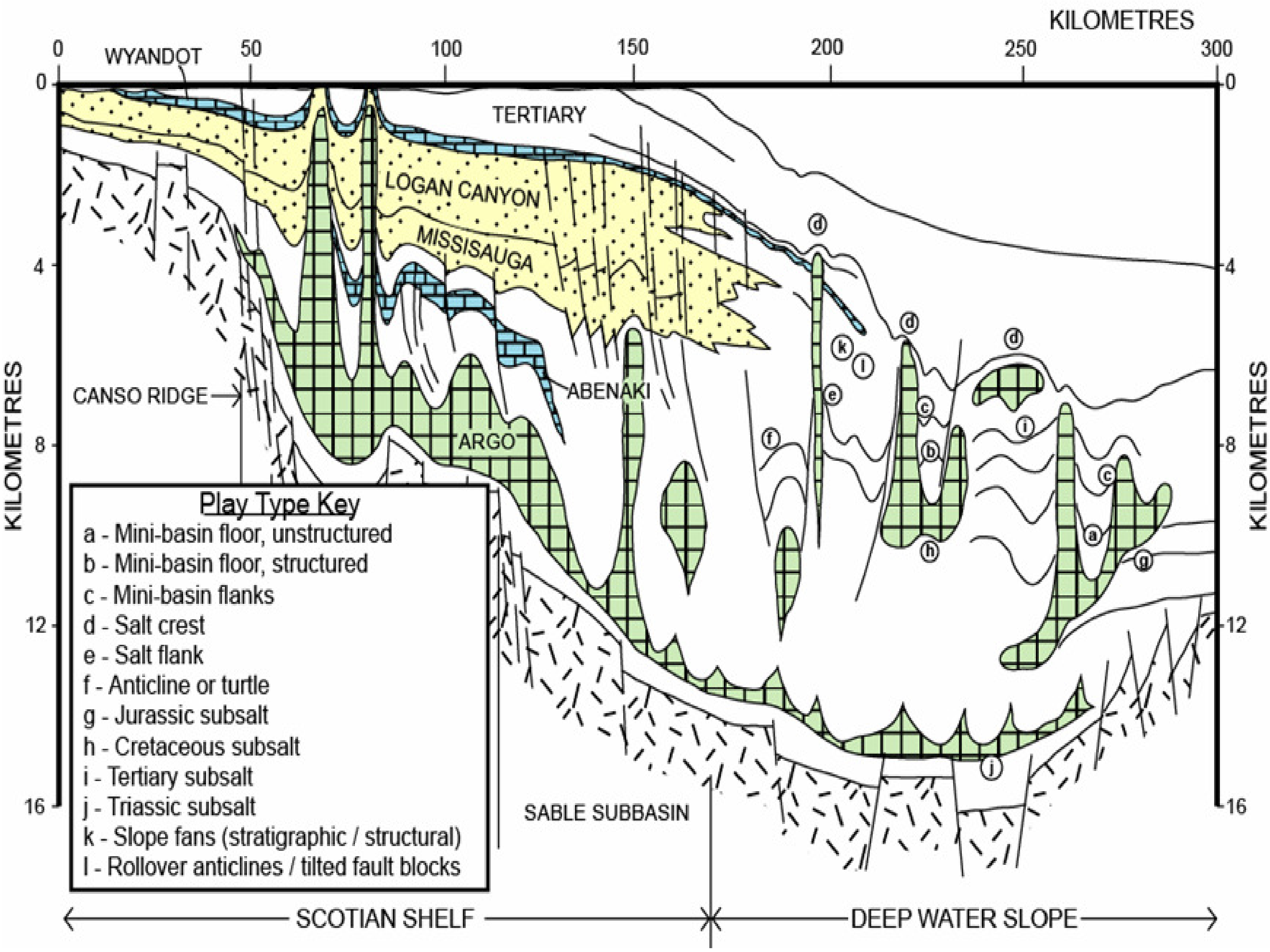


Figure 175. Stylized cross-section of the major shelf formations on the Scotian Shelf, extended to show equivalent deep-water plays (Kidston et al., 2001).

Play Setting	Play Type	(1) Main Diapiric Zone	(2) Central Canopy Complex	(3) Salt Withdrawal Area	(4) North East Complex	(5) Central Upper Slope	(6) Western Upper Slope
Inter-Salt	a. Mini-Basin Floor	1					
	b. Floor Structured						
	c. Mini-Basin Flank	2					
Supra-Salt	d. Crest	3		7			
	e. Flank			8			
	f. Anticline (Turtle)		5	9	10		
Sub-Salt	g. Jurassic	4					
	h. Cretaceous		6				
	i. Tertiary						
Synrift	j. Triassic/Jurassic						
Other	k. Slope Fans					11	
	l. Anticline/ Fault Block						12

Table 12. Play Types by Play Area (Kidston et al., 2002).

PLAYS		UNRISKED Recoverable Gas (Bcf)			RISKED Recoverable Gas (Bcf)		
Play Ranking	**Play No.**	**P90**	**Mean**	**P10**	**P90**	**Mean**	**P10**
Diapiric Area Salt Flanks	**2**	3971	10304	18557	0	3280	11720
Diapiric Area Basin Floors	**1**	2872	7113	12521	0	2533	8156
Western Upper Slope	**12**	2712	6149	10463	0	3052	8336
Central Upper Slope	**11**	2359	5289	8956	0	3372	7753
Central Canopy Suprasalt	**5**	1755	4107	6975	0	1531	5028
Salt Withdrawal Structured	**9**	986	2449	4332	0	481	2097
Central Canopy Subsalt	**6**	738	1712	2938	0	290	1351
Salt Withdrawal Flanks	**8**	608	1490	2590	0	294	1267
East Canopy Suprasalt	**10**	664	1432	2358	0	351	1460
Diapiric Area Salt Crests	**3**	283	653	1118	0	160	653
Salt withdrawal Crests	**7**	144	295	472	0	58	268
Diapiric Area Subsalt	**4**	55	109	176	0	17	88
Totals		**30666**	**41102**	**52848**	**4600***	**15200**	**27700**
** = The statistical sum of 12 distributions results in a possible outcome.*							

Table 13. Total Unrisked Recoverable Gas, Oil and BOE by Play (Kidston et al., 2002).

A ranking of the 12 plays based on the unrisked recoverable quantities of non-associated gas is presented in Table 13. The mini-basin flanks and floors of the main diapiric area have the highest potential followed by the upper slope areas.

The total summed results of the 12 plays are tabulated in Table 14. The four quadrants of the table are for in-place and recoverable hydrocarbons, and with and without geological play risk. The main points of the probability distribution from the Monte Carlo simulation are given as P90, Mean and P10. The output products are non-associated gas, gas liquids, oil and solution gas.

	UNRISKED IN-PLACE			UNRISKED RECOVERABLE		
	P90	**Mean**	**P10**	**P90**	**Mean**	**P10**
Gas (Tcf)	**45.8**	**60.4**	**77.2**	**30.7**	**41.1**	**52.8**
Oil (BB)	**10.7**	**14.4**	**18.6**	**3.4**	**4.7**	**6.2**
sub-total (BOEB)	**18.3**	**24.5**	**31.5**	**8.5**	**11.6**	**15.0**
Solution Gas (Tcf)	**17.2**	**23.0**	**29.5**	**5.4**	**7.5**	**9.8**
NGL (BB)	**1.4**	**1.8**	**2.3**	**0.9**	**1.2**	**1.6**
sub-total (BOEB)	**4.3**	**5.6**	**7.2**	**1.8**	**2.4**	**3.2**
Total (BOEB)	**22.8**	**30.1**	**38.3**	**10.5**	**14.0**	**18.0**
	RISKED IN-PLACE			**RISKED RECOVERABLE**		
	P90	**Mean**	**P10**	**P90**	**Mean**	**P10**
Gas (Tcf)	**7.0**	**22.1**	**39.5**	**4.6**	**15.2**	**27.7**
Oil (BB)	**1.3**	**5.0**	**9.4**	**0.4**	**1.7**	**3.2**
sub-total (BOEB)	**2.5**	**8.7**	**16.0**	**1.2**	**4.2**	**7.8**
Solution Gas (Tcf)	**2.1**	**7.9**	**14.7**	**0.7**	**2.6**	**5.0**
NGL (BB)	**0.2**	**0.7**	**1.2**	**0.1**	**0.5**	**0.8**
sub-total (BOEB)	**0.55**	**2.02**	**3.65**	**0.22**	**0.9**	**1.63**
Total (BOEB)	**3.1**	**10.7**	**19.6**	**1.5**	**5.1**	**9.3**

Table 14. Assessment Results, Deepwater Slope (Imperial Units) (Kidston et al., 2002).

The main emphasis is on gas potential, therefore, the main inference to be drawn from Table 14 is the undiscovered gas potential for the deepwater slope is estimated to be between 15 and 41 Tcf. This covers the range of uncertainty between a fully risked recoverable value (15 Tcf) where no plays are proven to exist, and a recoverable value (41 Tcf) where all plays are proven to exist.

7.2 Revision of the 2002 Assessment

The starting point in the 2007 revision was to examine the input parameters for each of the three areas where the new wells were drilled. This would include the play level adequacies (or play risk) (Table 15) and the reservoir quality parameters (Figure 176).

Play	Source	Reservoir	Trap	Overall
1. Diapir Area – Mini-Basin Floors	.80	.50	.80	.32
2. Diapir Area – Mini-Basin Flanks	.80	.50	.80	.32
3. Diapir Area – Mini-Basin Salt Crests	.70	.50	.70	.25
4. Diapir Area – Leading Edge Subsalt	.90	.20	.90	.16
5. Central Canopy Suprasalt	.80	.60 (.50)	.80	.38 (.32)
6. Central Canopy Subsalt	.80	.30	.70	.17
7. Withdrawal Area – Salt Crests	.70	.40	.70	.20
8. Withdrawal Area – Salt Flanks	.70	.40	.70	.20
9. Withdrawal Area – Structures	.70	.40	.70	.20
10. Eastern Complex – Suprasalt	.70	.50	.70	.25
11. Central – Upper Slope	1.00	.80 (.50)	.80 (1.00)	.64 (.50)
12. Western – Upper Slope	.90	.70 (.40)	.80	.50 (.29)

Table 15. 2007 Assessment Play Level Adequacies. Bold text designates play areas that were revised. Revised values are in brackets.

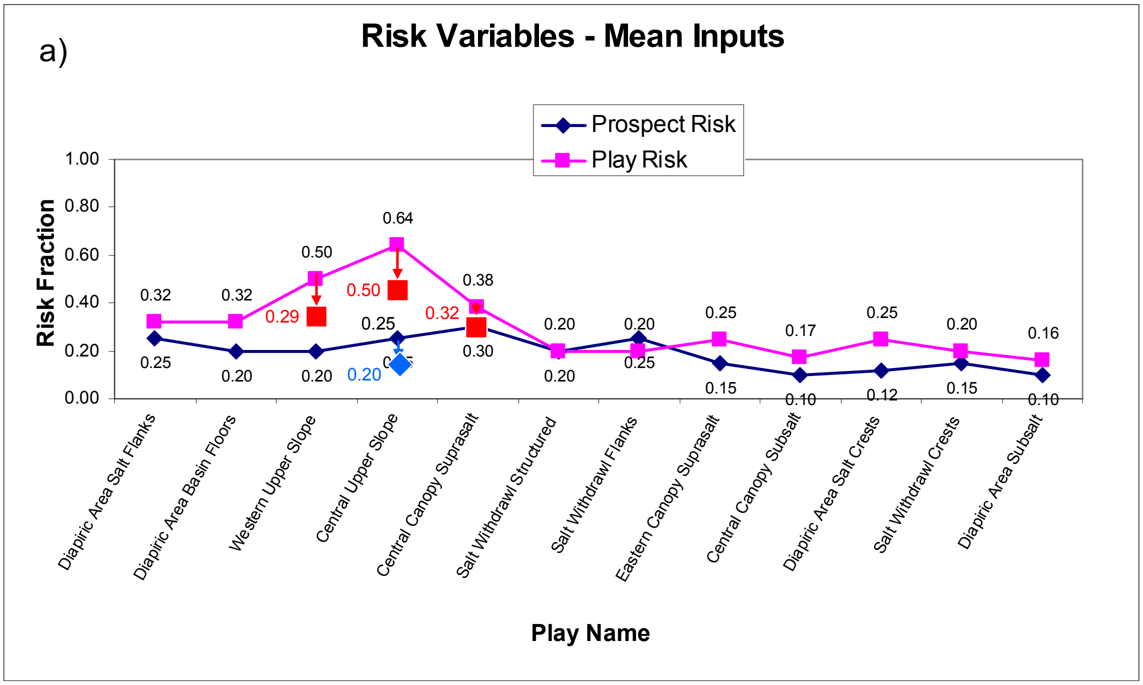


Figure 176. a) Graph highlighting the changes to prospect and play risking from the previous assessment. b) Graph highlighting the change in reservoir parameters. The red squares and light blue diamond show which variables were changed.

Play Type Play 11 - Upper Slope (Tert/Cret)

Reservoir Parameters	Probability 1	0.5	0	MEAN
Total Play Area (km^2)	4084.2	4538	4991.8	4538
Tested Area	200	200	200	200
Fraction of Area Under Trap	0.1	0.2	0.3	0.2
Fraction of Trap Filled	0.3	0.4	0.5	0.4
Discounted Play Area (km^2)	116.5	347.0	718.8	347.0
Net Pay (m)	15	50	100	55
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	4500	5000	6000	5166.667
Z	1.1	1.25	1.4	1.25
Gas Volume Factor	325.2	306.0	305.0	312.3
Fraction of Pore Volume Oil Bearing	0.2	0.3	0.4	0.300
GOR (m3/m3)	261.77	290.85	349.02	300.55
Formation Volume Factor (Oil)	1.842	1.935	2.122	1.966
Prospect Adequacy	0.10	0.20	0.30	0.2
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.2	0.35	0.5	0.35
Gas Recovery Factor	0.5	0.7	0.9	0.7
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

Risk Parameters		
Play Adequacy	50	0

Other Parameters				
Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	88	102	130	106.6667
Reservoir Pressure (kPa)	45191.30	50201.30	60221.30	51871.30

Gas to BOE conversion factor (MCF/BBL) 6

Figure 177. Input sheet for Play 11 – Central Upper Slope.

7.2.1 Central Upper Slope (Play #11)

The Central Upper Slope (Play #11) is the most affected by the results of recent drilling, with five of the seven recent wells drilled in that area: Newburn, Balvenie, Annapolis (2) and Crimson. The lack of reservoir encountered was the most significant failure factor and despite the equivocal structural and salt movement reconstructions, the play adequacy factors required reduction. The 64% overall adequacy (Table 15) consisted of source (100%), reservoir (80%) and trap (80%). Annapolis proved the existence of a source and trap at the play level but lacked significant quantities of reservoir facies. With source and trap having a 100% probability, and a decreased reservoir probability (50%), the resulting play adequacy was reduced to 50%.

The overall play area was also reduced by 50km^2 for each well or 200km^2 for the four wells (excluding the Annapolis B-24 well); an insignificant reduction but it respects the well results' effects on the play area. Pay thickness ranges were reduced from 25-75-150m to 15-50-100m, and the prospect level chance of success was reduced from 15-25-35% to 10-20-30%. The revised input sheet is shown in Figure 177. These changes resulted in a reduction of the play potential from a risked mean recoverable of 3372 Bcf to 1130 Bcf, a 66% reduction (Figure 178).

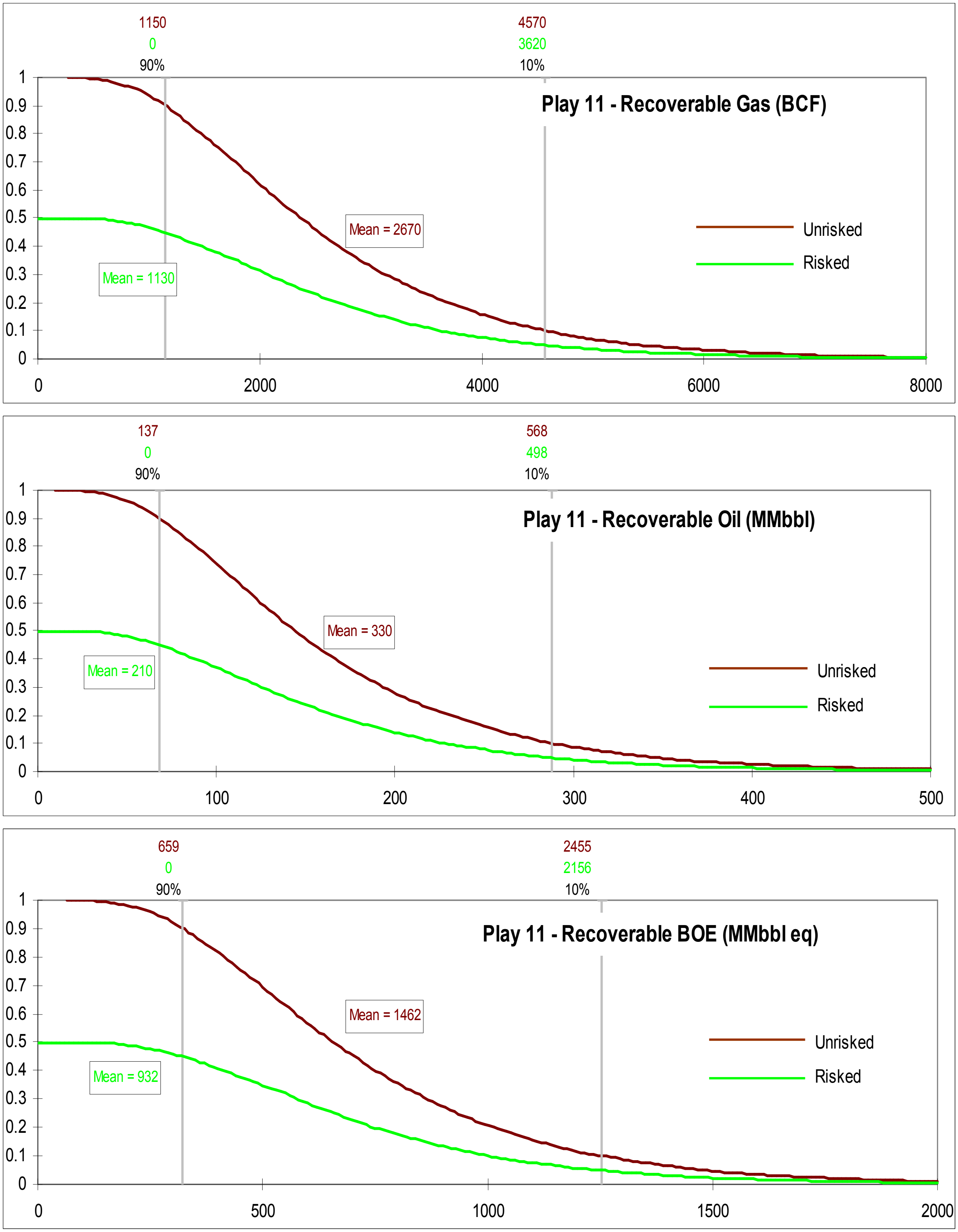


Figure 178. Updated assessment results for Play 11 – Central Upper Slope.

Play Type Play 12 - Upper Slope (Cret/Jura)

Reservoir Parameters	Probability			
	1	0.5	0	MEAN
Total Play Area (km^2)	12212.4	13576	14939.6	13576
Fraction of Area Under Trap	0.1	0.2	0.3	0.2
Fraction of Trap Filled	0.3	0.4	0.5	0.4
Discounted Play Area (km^2)	366.4	1086.08	2240.9	1086.1
Net Pay (m)	20	50	100	56.66667
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	4000	4500	5500	4666.667
Z	1.1	1.25	1.4	1.25
Gas Volume Factor	300.8	286.2	289.7	293.0
Fraction of Pore Volume Oil Bearing	0.3	0.5	0.6	0.467
GOR (m3/m3)	232.68	261.77	319.94	271.46
Formation Volume Factor (Oil)	1.748	1.842	2.029	1.873
Prospect Adequacy	0.10	0.20	0.30	0.2
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.2	0.35	0.5	0.35
Gas Recovery Factor	0.5	0.7	0.9	0.7
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

Risk Parameters		
Play Adequacy	28.8	0

Other Parameters				
Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	74	88	116	92.66667
Reservoir Pressure (kPa)	40181.30	45191.30	55211.30	46861.30

Gas to BOE conversion factor (MCF/BBL) 6

Figure 179. Input sheet for Play 12 – Western Upper Slope.

7.2.2 Western Upper Slope (Play #12)

The play adequacy factor (Table 15) for the structured fan play in the Western Upper Slope (Play #12) was also reduced. The presence of reservoir estimate dropped from 70% to 40% to reflect a lack of reservoir in the perceived best part of the slope: in front of the sand-rich Sable paleodelta. This resulted in an overall play adequacy reduction from 50% to 29%. The revised input sheet is shown in Figure 179.

It should be recalled that the dominant play type for this play area was pre-Tertiary fans in structured anomalies, not Tertiary age fans like the Torbrook well target in this region. Regardless, this change was still warranted. The re-assessment reduced the risked mean recoverable values from 3052 Bcf to 1770 Bcf, a reduction of 42% (Figure 180).

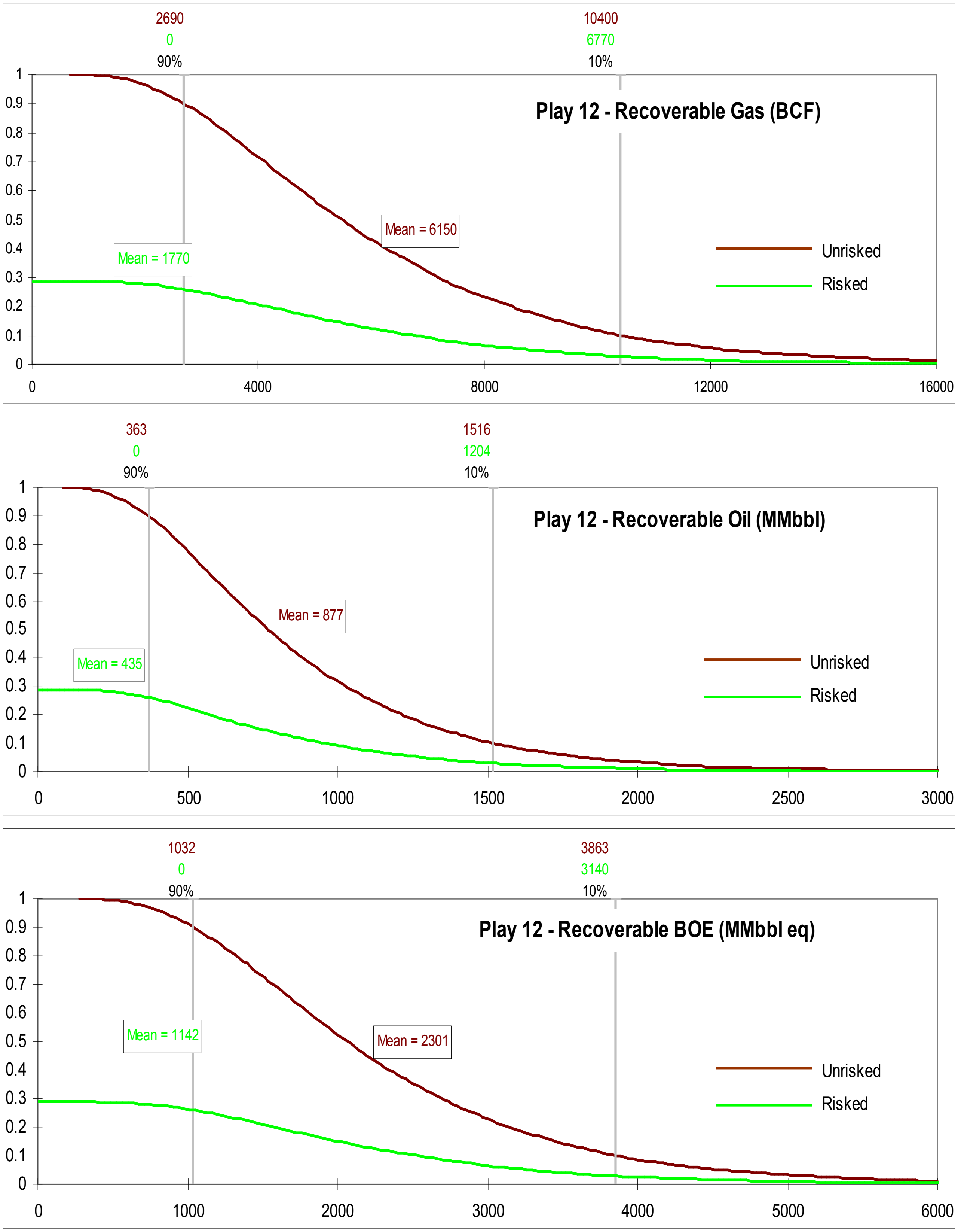


Figure 180. Updated assessment results for Play 12 – Western Upper Slope.

Play Type   Play 5 - Suprasalt Structures - Tertiary

Reservoir Parameters		Probability		
	1	0.5	0	MEAN
Total Play Area (km^2)	1198	3844	4205	3082.333
Fraction of Area Under Trap	0.1	0.2	0.3	0.2
Fraction of Trap Filled	0.3	0.4	0.5	0.4
Discounted Play Area (km^2)	35.9	307.52	630.8	246.6
Net Pay (m)	25	75	125	75
Porosity	0.1	0.2	0.25	0.183333
Hydrocarbon Saturation	0.6	0.7	0.8	0.7
Depth of Reservoir (m)	4500	5000	5500	5000
Z	1.15	1.25	1.35	1.25
Gas Volume Factor	337.2	330.7	323.7	330.7
Fraction of Pore Volume Oil Bearing	0.2	0.3	0.4	0.300
GOR (m3/m3)	261.77	290.85	319.94	290.85
Formation Volume Factor (Oil)	1.842	1.935	2.029	1.935
Prospect Adequacy	0.20	0.30	0.40	0.3
Liquids Yield (BBL/MMCF)	20	30	40	30
Oil Recovery Factor	0.2	0.35	0.5	0.35
Gas Recovery Factor	0.5	0.7	0.9	0.7
H2S content	0	0	0	0
CO2 content	0.016	0.019	0.022	0.019
Surface Loss Factor		0.05		
Marketable Gas Fraction	0.928	0.931	0.934	0.931

Risk Parameters

Play Adequacy	32	0

Other Parameters

Pressure gradient (kPa / m)	10.02	Sfc Pressure (kPa)		101.3
Temperature gradient (°C / 100 m)	2.8	Surface Temp (°C)		4
	1	0.5	0.0	MEAN
Reservoir Temperature (°C)	60	74	88	74
Reservoir Pressure (kPa)	45191.30	50201.30	55211.30	50201.30

Gas to BOE conversion factor (MCF/BBL)   6

Figure 181. Input sheet for Play 5 – Central Canopy Suprasalt.

7.2.3 Central Salt Canopy (Play #5)

Given the reduced reservoir presence in the Central Upper Slope and the Weymouth well results, it was determined that the reservoir adequacy in the basinward Central Canopy area had to be reduced from 60% to 50% (Table 15). This lowered the play chance value from 38% to 32%. The revised input sheet is in Figure 181. The risked mean recoverable was reduced from 1531 Bcf to 1321 Bcf, a reduction of 13% (Figure 182).

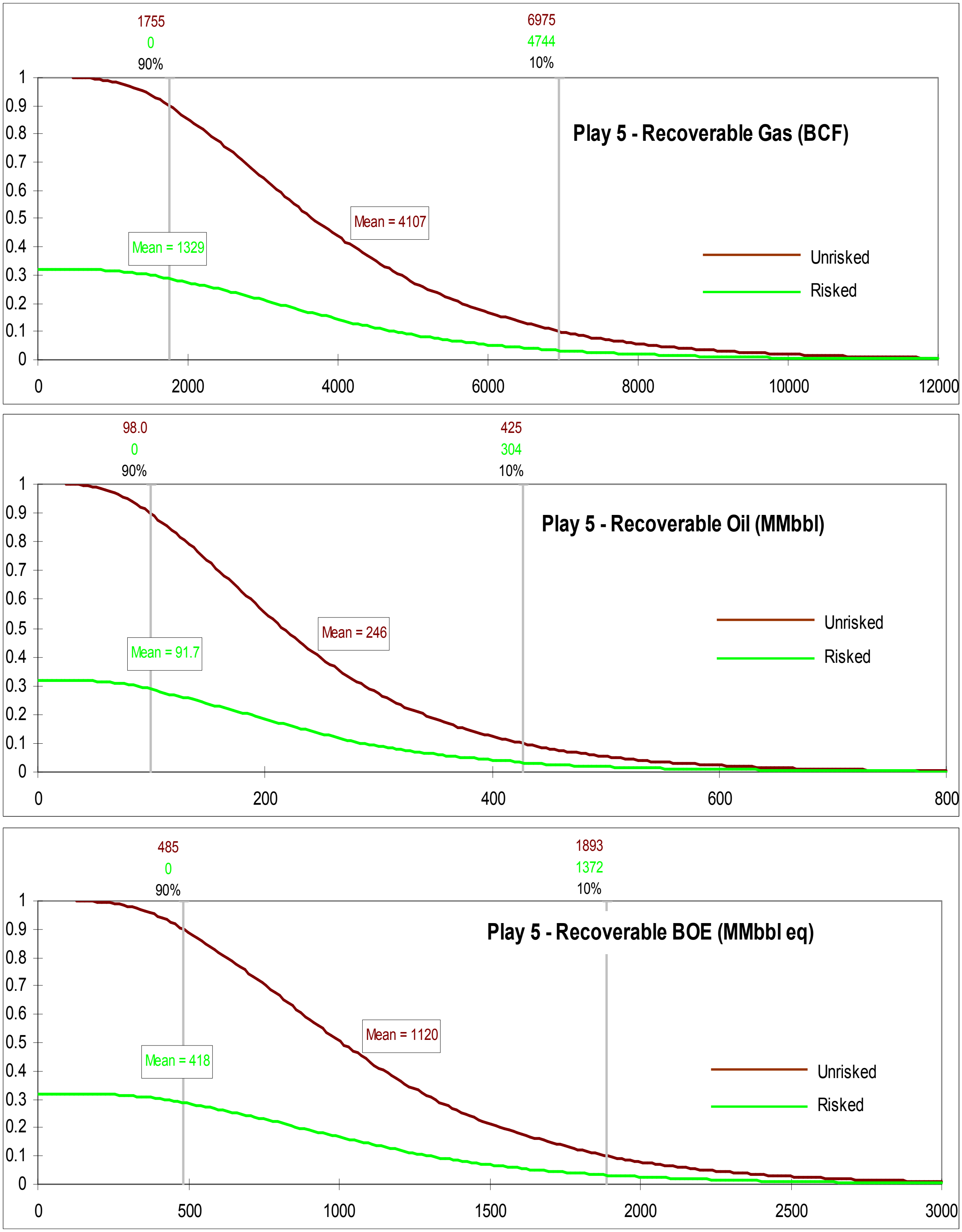


Figure 182. Updated assessment results for Play 5 – Central Canopy Suprasalt.

7.3 Overall Assessment Impact

The re-assessment of three of the 12 plays reduces the risked mean recoverable gas from 15.2 Tcf to 11.6 Tcf, a reduction of 3.6 Tcf or 24%. Similarly, the unrisked mean recoverable was reduced from 41.1 Tcf to 38.5 Tcf, a reduction of 2.6 Tcf or 6% (Figure 183). The net result is the undiscovered gas potential of 15 to 41 Tcf has been revised to 12 to 39 Tcf, a modest reduction within the overall range of probabilistic analysis.

The risked recoverable oil fraction is reduced from a mean of 1.7 billion barrels to 1.3 billion barrels, and the unrisked mean is reduced from 4.7 to 4.5 billion barrels. The BOEB (billions of oil equivalent barrels) on a risked basis is reduced from 5.1 to 4.0, and the unrisked is reduced from 14.0 to 13.3. The overall impact of these revisions is minimal.

The re-assessment of the original 2002 study was required given that important new well and seismic data was now available from the first round of Scotian Slope deep water drilling. Although the well results were disappointing, those from the Annapolis and Newburn wells are encouraging since they proved the existence of an active petroleum system in the deepwater region. It is expected that future explorers will build upon this knowledge leading to a better understanding of the basin petroleum systems and discovery of significant hydrocarbon accumulations.

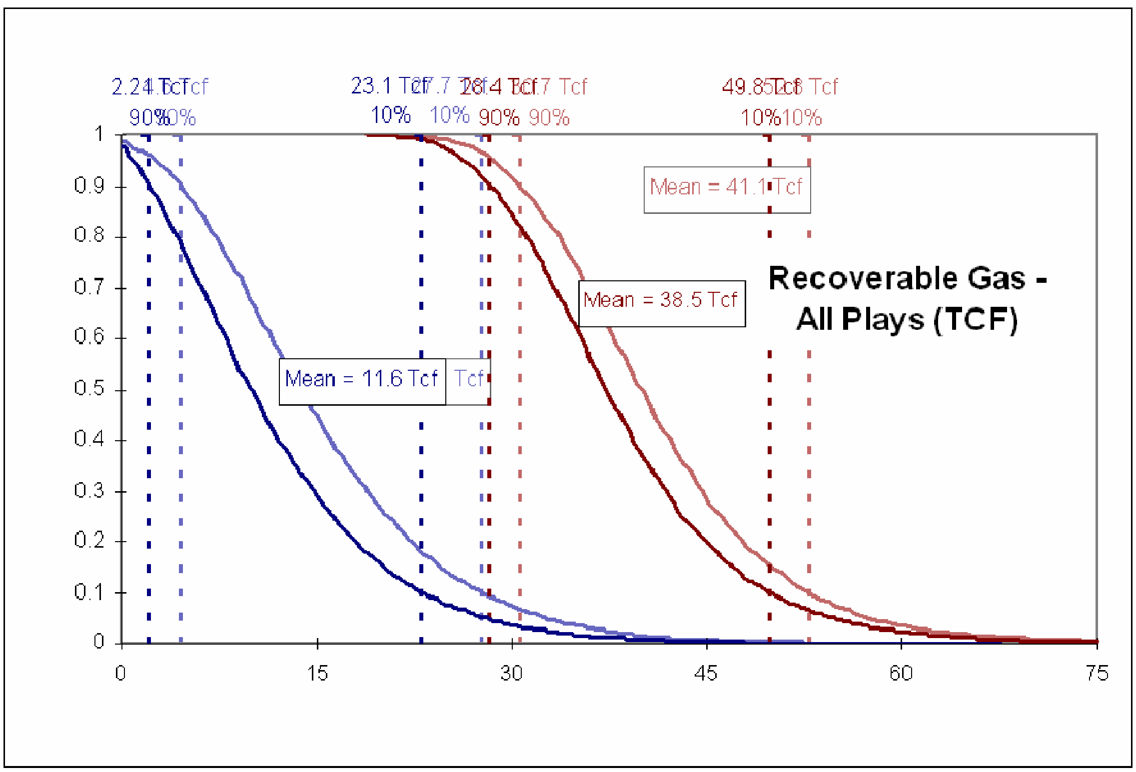
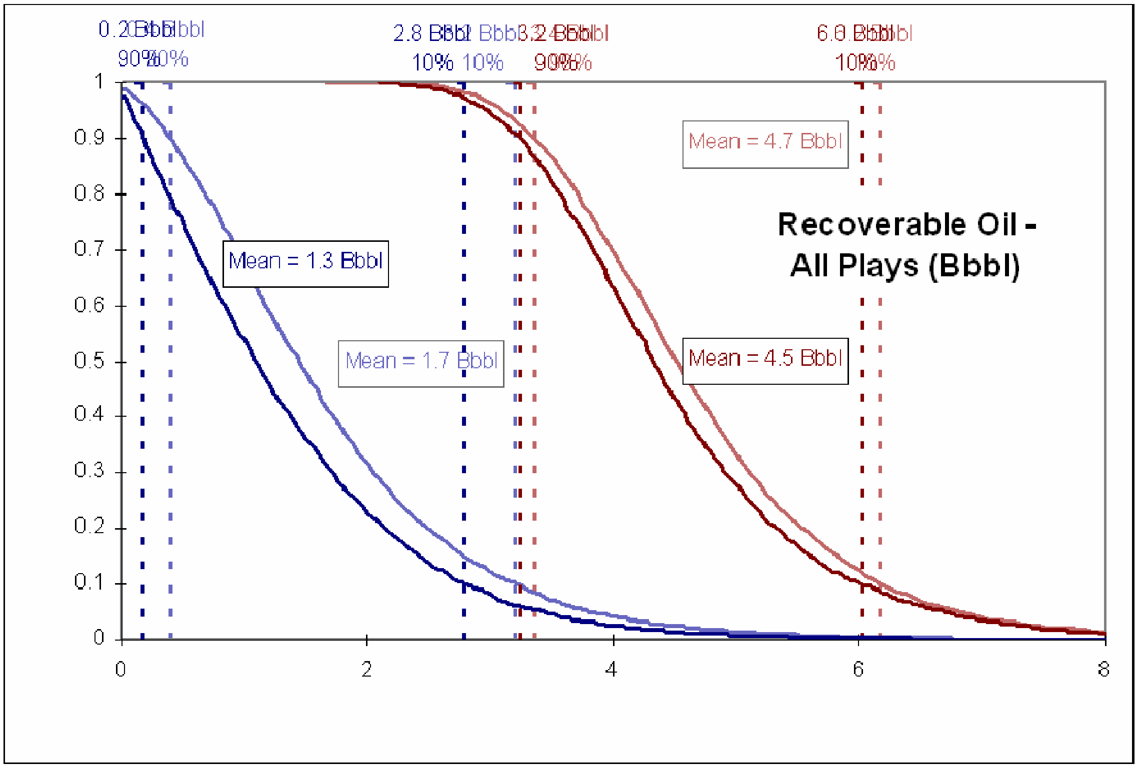


Figure 183. Recoverable gas, oil, and BOE equivalent, summed for all plays. The faded objects represent the results from the 2002 assessment.



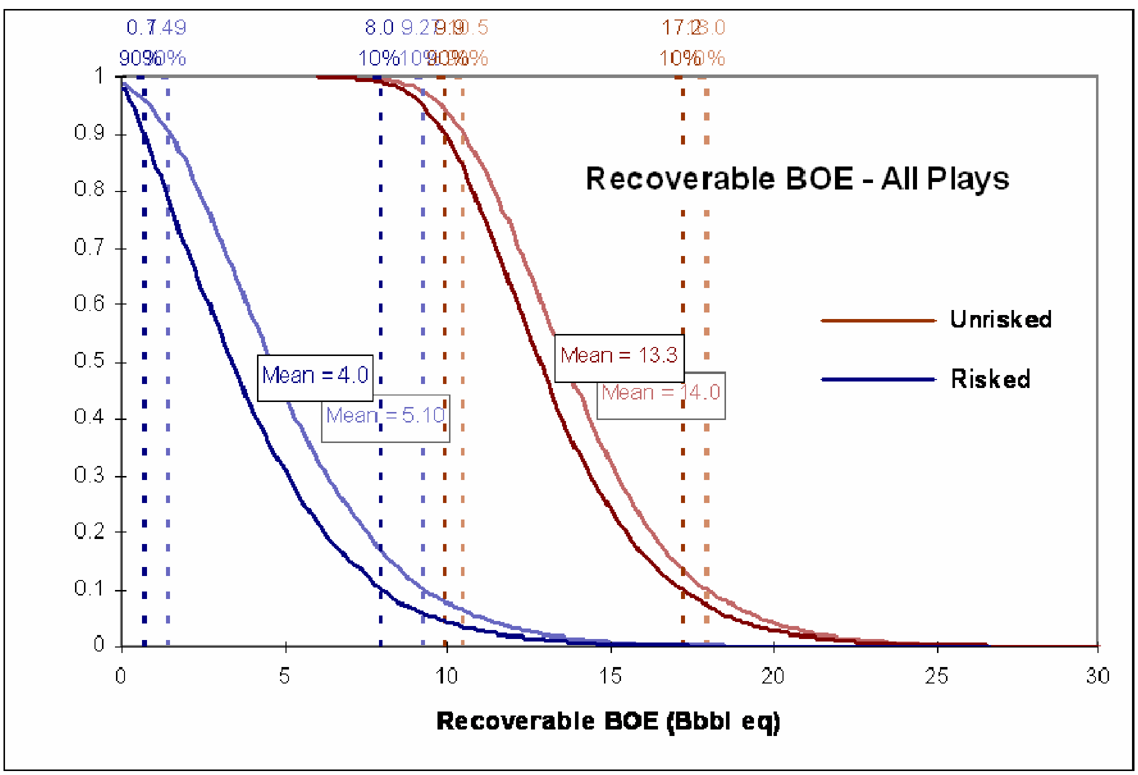


Figure 183 (cont). Recoverable gas, oil, and BOE equivalent, summed for all plays. The faded objects represent the results from the 2002 assessment.

8. CONCLUSIONS

8.1 General

The Scotian Slope covers an area of approximately 80,000km^2. The ten deepwater wells are few in number and spread out along the uppermost slope, hence a relatively small portion of the overall basin has been tested.

The final total depths vary substantially, and allowing for water depths, the actual rock penetration is between 1925m and 5090m per well. Except those whose targets were in the Tertiary, the wells had a range of pre-Tertiary penetrations between 1210m and 3219m with an average of 2582m per well. This is rather limited when judging the degree of basin evaluation accomplished by these ventures.

The four vintage wells were drilled almost 25 years ago and based entirely on 2D seismic. The Evangeline well stepped seaward from the Sable area to test the limits of the shelfal sands while the Tantallon well was the first to focus on turbidite sands as their target. Unfortunately, both wells encountered very little sand. The remaining wells, Shelburne and Shubenacadie, looked for North Sea look-alike Tertiary submarine fans and would likely not have been drilled in their present-day locations if based on modern seismic. Instead of submarine fans, they drilled erosional remnants which was, and continues to be, one of the potential pitfalls of fan recognition on seismic.

Of the seven recent wells, Newburn, Balvenie, Annapolis (2) and Crimson were concentrated in front of the Sable paleodelta looking for deepwater fan equivalents of shelfal sands. Of these, Annapolis G-24 found 27m of generally thin, gas-bearing sands. Crimson was a follow-up to Annapolis and encountered a single 13m thick reservoir quality sand interval which is calculated as wet on logs. Newburn discovered several thin (2-3m) gas bearing sands.

Of the remaining two wells, Weymouth was a subsalt test in front of the central Sable area but failed to find any sands. Torbrook revisited the earlier Tertiary fan play along the Western Slope and probably drilled a sand-poor slump instead of a fan.

Studies from the successful analogue basins (Gulf of Mexico, West Africa, Brazil), where the success factors are largely recognized, are facilitated by huge amounts of available well and seismic data. Relative to these regions the Scotian Slope is a frontier basin that has barely been explored. There needs to be a critical mass of data and knowledge generated before the basin gives up its secrets.

The recent exploration effort was remiss by curtailing the cutting any conventional cores despite the rational explanations and reasoning (i.e. costs) of the operators. Large-diameter cores provide a level of ground-truthing unmatched by any other data for information on reservoir properties, lithofacies, environment of deposition, geochemical analyses, rock properties, etc. The evaluation of the basin suffers every time this is ignored and each well is less diagnostic than it could have been.

Recent drilling in the deepwater offshore Nova Scotia has been costly, especially for the operator’s first attempt. Pre-spud pore pressure predictions were often incorrect resulting in considerable time delays as the operators attempted to manage the overpressure regime. In addition, operators often experienced considerable delays caused by unforeseen mechanical and equipment failures which significantly increased well costs. However, Marathon demonstrated, with experience in the basin from the Annapolis and Crimson wells, that with proper planning and research the above factors could be mitigated resulting in a significant reduction in well costs.

8.2 Specific

Gas discovered at Annapolis and Newburn confirmed that an active petroleum system exists in the deep water Scotian Slope. Furthermore, many of the gas-bearing sands were encountered below 5000m with average porosities from 14-19% (maximum 25%). This indicates that good quality reservoir sands can be encountered at considerable depth that further expands the zone of prospectivity.

Based on paleoenvironmental interpretations from the biostratigraphic data of all wells except Torbrook and Weymouth (unavailable), the presumed Cretaceous age deep water sediments penetrated were in fact deposited in relatively shallow water outer shelf and upper slope settings. This knowledge will have a profound, but ultimately positive impact, on future exploration, play genesis and petroleum systems modelling.

Submarine fan prediction relies on high-quality seismic data and signal attribute analyses which have proven to be very successful in Tertiary strata in the Gulf of Mexico, offshore Brazil, West Africa, Mauritania, etc. The Tertiary fan exploratory technique used at Torbrook was a sophisticated application of seismic analyses used successfully in the North Sea and other areas. Unfortunately, the well results demonstrated the non-uniqueness of the geological interpretation.

Play and prospect generation requires 3D seismic surveys which is becoming increasing cost-effective even at regional scales. Most significantly, no published sequence stratigraphic research exists for the Scotian Basin. This is a vital component necessary for the determination of the basin's geological history and conceptualizing petroleum systems in order to enhance the basin's prospectivity and encourage exploration.

These same exploration techniques are less applicable in older pre-Tertiary rocks like the bulk of the plays on the Scotian Slope due to much poorer seismic resolution. The reasons are not clear, but changes in rock properties are obviously a factor. Therefore, explorers have to turn to mapping structural traps and proceed to high-grade ones with demonstrable, yet highly interpretive, inversion histories from a paleodepositional low to a present-day structural high. The alternative is to drill stratigraphic traps which are also high risk.

Time-depth conversion and isopach thicks with relatively higher amplitudes became the approach used at Newburn, Balvenie, Annapolis and Crimson. This approach did not work out, excepting Annapolis to some degree, hence the seismic tool including the interpretive methods is not readily predicting reservoir.

Industry has yet to drill a Gulf of Mexico style mini-basin or turtle structure, i.e. an unequivocal paleodepocentre on the Scotian Slope although as the figures show there are a large number of these features extant. While the lithology of the sedimentary sequences remains unknown, they nevertheless remain very attractive targets with the potential to contain significant reserves. The geological restoration models for inversion of paleodepocentres have to deal with deformation caused by mobile salt features and other structural forces. This remains poorly understood for this basin, and, at the prospect level.

The lack of sand in the wells suggests possible sediment bypass zones, the lack of a source of coarse clastics, or entrapment at the shelf margin. The erosion of the Appalachian hinterland should have provided abundant coarse material but what proportions remain trapped on the shelf or moved into deeper water is not understood. Linked shelf canyon feeder systems to submarine fans have not been established, though new research points to the existence and recognition of shelf-margin deltas on the outer fringes of the Sable delta (Cummings and Arnott, 2005; Cummings et al., 2006).

8.3 Assessment

The Board's 2002 assessment was a summation of 12 different play types within six play areas. Recent drilling affected three of those 12 runs to varying degrees in the 2007 re-assessment. The Central Upper Slope (Newburn, Balvenie, Annapolis, and Crimson) was most affected followed by the Western Upper Slope (Torbrook) and the Central Salt Canopy (Weymouth). A graphic comparison of the 2002 and 2007 assessments is presented in Figure 184.

Annapolis notwithstanding, the general lack of sand in the wells located in front of the Sable paleodelta in the Central Upper Slope had an adverse impact on the play adequacy values for the presence of reservoir and the net pay assumptions in that area. The risked mean recoverable was commensurately reduced from 3.4 Tcf to 1.1 Tcf.

The Western Upper Slope (Torbrook) was not reduced by the well results because the Tertiary fan play was not assessed in the 2002 Assessment due to the thermal immaturity of the Tertiary section. However, it was reduced for presence of reservoir in the pre-Tertiary section as a function of the reduction in the adjacent Central Upper Slope. The risked mean recoverable was reduced from 3.0 Tcf to 1.7 Tcf.

Similarly, the Central Salt Canopy was reduced more as a function of the Central Upper Slope reduction than as a result of the Weymouth well because it was a high risk test. The risked mean recoverable for the play area was reduced from 1.5 Tcf to 1.3 Tcf.

Cumulatively, the impact of the seven recent deepwater wells on the deep water Scotian Slope's undiscovered gas potential is minimal, with the total mean risked potential by area shown in Figure 185. In simplest terms, a rerun of the numerical analysis has reduced the undiscovered gas potential from a range of 15-41 Tcf to 12-39 Tcf. The oil fraction was similarly reduced from a range of 1.7-4.7 to 1.3-4.5 billion barrels.

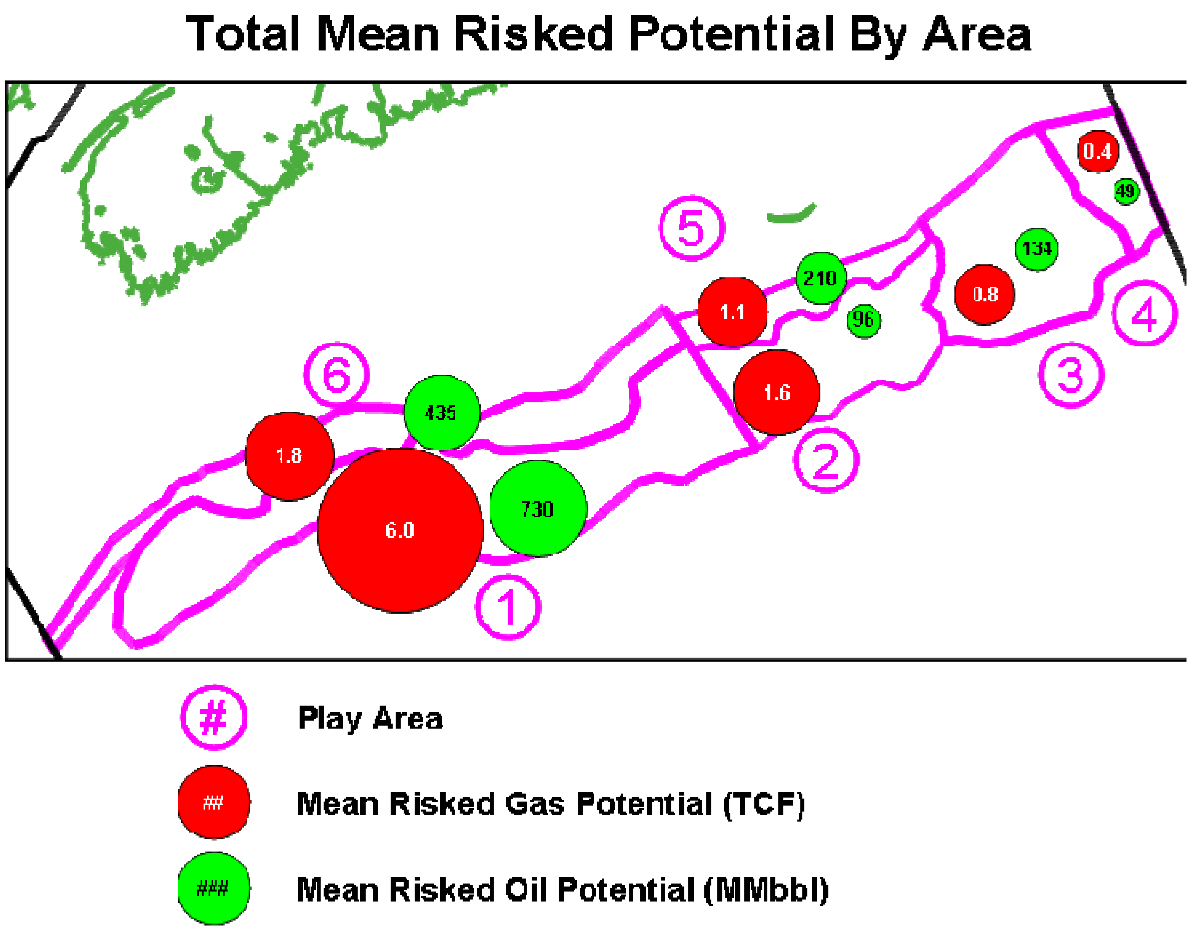


Figure 187. Risked potential by deepwater area. Bubble sizes are proportional to the mean resource potential.

GLOSSARY

allochthonous: Formed or produced elsewhere than in its present place; of foreign origin, or introduced.

autochthonous: Formed or produced in the place where it is now found.

BB: Billion barrels (10^9; E9)

Bcf: Billion cubic feet (10^9; E9)

BOE: Barrels of Oil Equivalent

BOEB: Billion of Oil Equivalent Barrels

BBOE: Billion Barrels Oil Equivalent

conceptual play: An exploration play that does not yet have discoveries or reserves but which geological analysis indicates may exist.

contourite – A layer of coarse sediment in a marine-mud sequence, usually consisting of fine sand or coarse silt deposited on the continental rise by contour-following bottom currents.

deterministic calculation: Arithmetic calculation of variables.

discovery: The term applies to the granting by CNSOPB of a Significant Discovery License (SDL) which means oil and/or gas was tested to surface in significant quantities that have potential for future commercial development.

established play: An exploration play that has been demonstrated to exist by the discovery of one or more pools. Commerciality may or may not be a factor in the definition.

fluvial: Of, or pertaining to, a river or rivers.

erosional remnant – A relict positive relief topographic feature created by the erosion of surrounding strata or rock. In deepwater settings, the processes can be the result of persistent lateral (slope parallel) deep sea bottom contour currents.

EUR: Estimated Ultimate Recovery equals, at any point in time, the sum of produced, proven reserves and undiscovered potential.

GIP: Gas-in-place

GOM: Gulf of Mexico

GSC: Geological Survey of Canada

lacustrine: Pertaining to, produced by, or formed in a lake or lakes.

ma: millions of years

MB: Thousand barrels (10^3; E3)

Mcf: Thousand cubic feet (10^3; E3)

mean: A statistical measure of central tendency; the risk-weighted average value of all possible outcomes / repeated trials.

median: A statistical measure of central tendency; the arithmetic average, or, the 50% probability.

Monte Carlo Simulation: A statistical procedure where variables are expressed as probability distributions and randomly sampled to create an output distribution. Number of random samples commonly between 5,000 and 10,000.

MMB: Million barrels (10^6)

MMcf: Million cubic feet (10^6)

MMS: Minerals Management Service, U.S. Department of the Interior

mya: million years ago

New Field Wildcat (NFW): The first well on a prospect or geological feature that is testing a new structure or play concept. Such a feature may straddle more than one fault block. As opposed to a delineation well, step-out, development, injector, etc.

NGL: natural gas liquids

OIP: Oil-In-Place

OOIP: Original-Oil-In-Place

play: A geological formation, or structural or stratigraphic trend, which has similar lithologic, reservoir or other characteristics extending over some distance or extent.

potential: Unproven quantities of recoverable hydrocarbons that may exist.

prospect: A singular structure or geologic feature that has the necessary attributes to contain hydrocarbons and hence be a drilling target.

reserves: Quantities of oil, gas and related substances that are proven to exist in known accumulations and are believed recoverable at some point in time. This includes both discovered initial reserves and discovered unrecoverable volumes.

resources: The total quantity of oil, gas and related substances that are estimated at a particular time to be contained in, or that have been produced from, known accumulations, plus, those estimated quantities in accumulations yet to be discovered. This includes both future initial reserves and future unrecoverable volumes.

slump – Gravity induced mass wasting usually without internal sedimentary structuring, caused by sediment loading and failure, earthquakes and the like.

stochastic calculation: Statistical calculation using Monte Carlo (or other) sampling techniques of input variables to result in a probability output distribution.

submarine fan (modern) – An active deepwater accumulation of sediment deposited in the shape of a fan or a cone along continental slopes or on basin plains located seaward of large rivers and submarine canyons.

Tcf: Trillion cubic feet (10^{12} ; E12)

turbidite – A sediment or rock deposited from or inferred to have been deposited by a turbidity current, characterized by graded bedding, moderate sorting, and well developed primary structures is the sequence noted in the Bouma cycle.

turbidite complex (ancient) – A subsurface submarine fan or fan complex described above.

turbidity current: A bottom-flowing current laden with suspended sediment, moving swiftly (under the influence of gravity) down a subaqueous slope and eventually spreading out horizontally on the deep floor of the body of water. Sand and finer sediments can be deposited as fans, channels, sheets etc., their sizes and shapes depending on the topography of the ocean bottom and slope, types of sediments in the flow, size and duration of the turbidite current and so forth. Turbidite currents and related subsea avalanches / slope failures are virtually instantaneous events that can move tremendous volumes of coarse grain sediment great distances far out into the abyssal depths over a period of several minutes to several hours.

turbidite system – A composite succession of various sand and mud gravity flow deposits that form depositional units

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