BOEM 2016-026

Atlantic Well Folio: Georges Bank Basin

Lydonia Canyon Block 145 No. 1 Well

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1.7. Lydonia Canyon 145-1

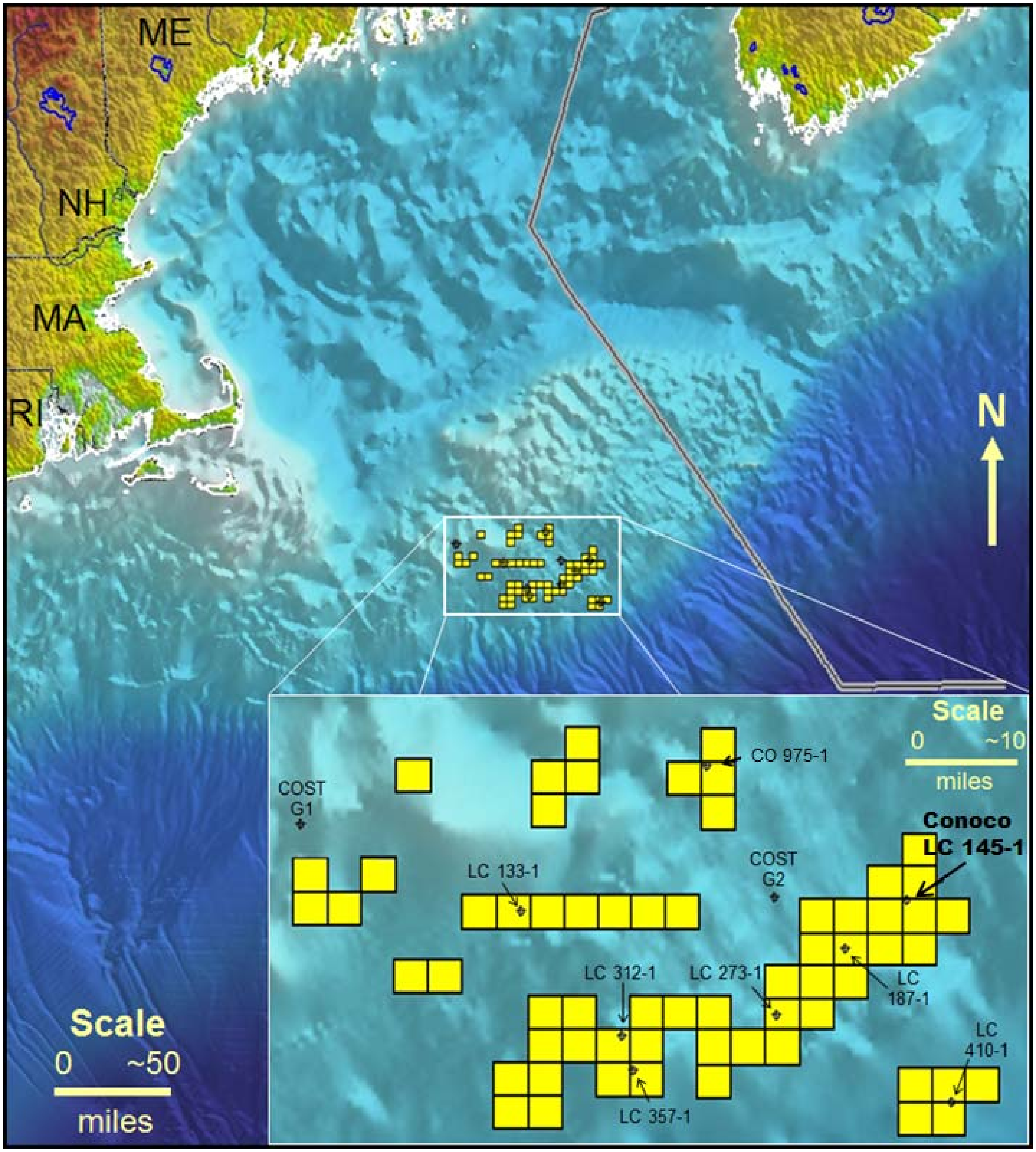

Figure 1. Location map of Georges Bank Basin (GBB), offshore Massachusetts, USA. Well locations are indicated by the symbol ⌖. Leases previously held in the area are shown in yellow.

Lydonia Canyon (LC) 145-1 was spudded on May 13, 1982 in 302’ of water and reached a total depth (TD) of 14,500’ on August 11, 1982 (Conoco Inc., 1982a). (Note: all depths in this report are measured depth unless otherwise specified.) The well operator, Conoco, spudded this, the 7th industry well in Georges Bank Basin (GBB), using the semisubmersible *Aleutian Key*. Drilled in 91 days, LC 145-1 was the 6th well completed in GBB (Exlog Inc., 1982). Several miles updip (northeast) of LC 273-1 and LC 187-1 (Fig. 1), along the same southwest-northeast structural trend, LC 145-1 was located ~20 miles from the present-day shelf edge (Edson *et al*., 2000) or ~215 miles east-southeast of Boston. It was drilled near the intersection of seismic lines pr (83)-102 (strike line) and 69 (D)-192 (dip line). There are several other 2D seismic lines nearby (Gulf Oil Corp., 1981). The location chosen and targets drilled were determined using data from these seismic lines and two joint industry Continental Offshore Stratigraphic Test (COST) wells (COST G-1 and G-2). Major objectives were postulated Late Jurassic porous shelf edge calcarenites and Middle to Early Jurassic carbonates deposited on a paleogeographic high in the interval from ~9,175’ to ~11,925’. Conoco requested and received permission to deepen the well to 14,500’ because of information received while drilling below 10,622’ during July, 1982 (Conoco Inc., 1982b). In a well summary report that mud log contractor Exlog provided for the well operator Conoco, these deeper objectives were interpreted as Late Jurassic reefs and Middle Jurassic dolomites from 12,500’–14,500’ (Table 1 and Fig. 2) (Exlog Inc., 1982).

The well was logged, cored, petrophysically and geochemically analyzed, and had Repeat Formation Tests (RFT) taken, all with consistently negative results. Minor gas shows were encountered while drilling. Free gas and formation water were recovered in an RFT, with the recovered gas subsequently analyzed (Conoco Inc., 1982c). Very low total organic carbon (TOC) and low porosities characterized this unsuccessful well. LC 145-1 was plugged and abandoned as a dry hole on August 18, 1982. The lease was relinquished on January 15, 1985 (Edson *et al*., 2000).

1.7.1 Objectives and Concepts

Conoco's Application for Permit to Drill (APD) outlined two Jurassic objective zones for LC 145-1 (Figs. 3 and 4). The first, at -9,100’ or 2.05 seconds two-way travel time, was interpreted as a Late Jurassic, porous calcarenite, deposited along the shelf edge. The second was anticipated to be Middle to Early Jurassic carbonates at -11,850’ (2.42 seconds) (Conoco Inc., 1982b). Conoco designated their possible hydrocarbon zones the ‘Near Base Late Jurassic’ and ‘Top Early Jurassic’ (Fig. 4). Both zones were interpreted to overlay a paleogeographic high interpreted to have been caused by a southwest–northeast trending Triassic–Jurassic age salt ridge. As the GBB plunges to the southwest, Conoco anticipated dry gas to migrate into this stratigraphic-structural trap (Conoco Inc., 1982b). BOEM’s predecessor organization, the Minerals Management Service (MMS) assigned no hydrocarbons in their presale resource/reserve estimate for LC 145-1 (MMS staff, 1985). Both the MMS and Conoco interpreted the objective to have been deposited in marginal marine to inner shelf environments.

1.7.2 Results

Drilling

LC 145-1 was essentially a straight hole, which was located at 40° 49’ 58.6” North latitude and 67° 17’ 07.0” West longitude (Conoco Inc., 1982a). While drilling, the only gas shows detected by the mud logger were 85 units from 9,165’– 9,185’ (consisting of C1 through C3), a 10 unit gas increase from 13,210’–13,225’ with C1 through C3, and ~125 units consisting entirely of C1 recorded from 13,360’–13,415’.

Subsequent logs and analyses indicated these gas increases were in tight zones and likely to represent gas that had been generated, but not migrated; *et al*, *in situ*. Three conventional cores were cut from 9,191’–9,227’ (immediately below the first show), from 10,622’–10,652’, and from 12,419’–12,448’ (Table 2), with full recovery of all 95’ of core cut (Core Laboratories Inc., 1982a). The conventional core cut and analyzed from 9,191’–9,227’ consisted of oolitic and microcrystalline limestone overlain by formations high in silt and shale, as seen on the mud log and our lithology log (Fig. 5). Porosities and permeabilities in this zone were low, averaging 2–3%, and typically with 0.01 mD of permeability or less respectively (Core Laboratories Inc., 1982a). In addition, 176 percussion sidewall cores were shot from 5,270’ to 14,191’ with reservoir and fluid properties analyzed for the 73 that had sufficient recovery for analysis and contained potential reservoir rocks (Core Laboratories Inc., 1982b).

Conoco attempted 72 RFTs. Over ¾ of them targeted the zones that had the 85 and 125 unit gas shows (9,165’– 9,185’ and 13,360’–13,415’ respectively). The 85 unit zone is within the margin of pre-drill interpretation error for the shallow objective prognosed at ~-9,100’. The “bright” seismic event corresponding to this target was associated with a lithologic transition from calcareous siltstone to a shaley, oolitic limestone (MMS, 1985), which Conoco noted in their APD might be the case (Conoco Inc., 1982b). Two RFTs from this zone recovered gas, one containing free gas and water.

Wireline logs were evaluated using Log Evaluation System Analysis (LESA) software to determine the lithologies and porosities for Conoco’s zones of interest. LESA confirmed the lithologies and porosities measured in the sidewall cores (Fig. 5). Near the second target at 11,850’ a tight, microcrystalline limestone with some shale was encountered. This lithology appears to continue for another ~450’ deeper in the sedimentary section. Dolomite interbedded with thin anhydrite intervals is the dominant lithologies from ~12,600’–TD (Fig. 5).

The structure targeted and evaluated by the LC 145-1 was a low-relief structure near the eastern margin of the Georges Bank Basin, (Fig. 6). The dipmeter log from LC 145-1 recorded low dips, flat to ~2°, generally to the southwest from 9,500’–12,500’. Below 12,500’dips increases to as much as ~10°, with a more easterly dip direction. From 13,150’ to TD the dips are sparse and erratic. Our seismic interpretations (Figs. 6, 7, and 8) confirm this, illustrating a structure that flattens with increasingly shallow depths with the intra-Oxfordian, intra-Tithonian, base Hauterivian, base Aptian, mid-Cenomanian, and base Tertiary events being essentially flat.

Seismic Interpretation

Seismic coverage across block LC 145 and the surrounding area consisted of 2D lines from several surveys acquired and processed in the late 1970’s and early 1980’s prior to drilling. The original MMS seismic interpretation was largely in agreement with Conoco’s. Both illustrated a southwest-northeast trending structural high. There were 12 seismic profiles covering block LC 145 shown in Conoco’s APD. Figure 4 shows line pr (83)-102 with Conoco’s interpreted ‘Near Base Late Jurassic’ at ~-9,100’ and ‘Top Early Jurassic’ near ~-11,850’.

Mapping completed for this folio was based on 8 sequence boundaries (SBs) initially identified and interpreted by GeoSpec, a CGG Company, using the two COST wells, and 5 industry wells as part of their seismic interpretation of the U.S. Atlantic OCS (GeoSpec, 2003). LC 145-1 was not included in the GeoSpec analyzed wells. However, one of the 5 wells was LC 187-1, located ~7 miles to the southwest. LC 145-1 was correlated with and seismically tied to this well to obtain the depths for its SBs.

Structure maps constructed using interpreted and gridded depth-converted, time-migrated seismic data on the intra-Oxfordian (SB3) and base Bathonian (SB2), along with an isochore for the entire mapped Jurassic section (SB1–SB4) were among those constructed (Figs. 7, 8, and 9) for this well folio. Conoco's shallowest target was located a few hundred feet above our intra-Oxfordian (Figs. 6 and 7) and their deeper target zone was a few hundred feet above our base Bathonian (Figs. 6 and 8). As noted above, this interpretation shows the LC 145-1 to have tested part of a low-relief structural uplift at or near the eastern edge of the GBB. Down-to-the-west faulting is well imaged on Figure 6, and shows up most clearly on the deepest interpreted seismic event and the Jurassic isochore (Fig. 9). No closure is interpreted on the deepest structure maps included in this folio (Figs. 7 and 8). Confirming the dipmeter data, structure at the objective horizons is subtle at LC 145-1, with the well near, but not at, the structural crest.

Biostratigraphy and Palaeoenvironment

A biostratigraphic report on LC 145-1 was completed by International Biostratigraphers Inc. (IBI) for Conoco (IBI, 1982) without access to the sidewall or conventional cores. From the fossil taxa (Table 3), they determined depths for the interpreted geologic ages, environment of deposition (EOD), and paleobathymetry. According to the IBI report, the well is interpreted to have bottomed in strata of late Middle Jurassic Bathonian age sediments. However, our wireline log correlations and seismic interpretation based on the work of GeoSpec (2003) show the well penetrated the base Bathonian seismic horizon, and therefore may have bottomed in older units, perhaps of early Middle Jurassic of Bajocian or Aalenian age. Table 4 summarizes our interpretation of these data.

1.7.3 Operations and Costs

Conoco Inc. (25%), Gulf Oil Corporation (25%), Sun Oil Company (20%), Getty Oil Company (20%), and Diamond Shamrock Corporation (10%) leased block LC 145 (Gulf Oil Corp., 1980). On December 18, 1979, lease OCS-A00179 was awarded during sale 42 for a winning bid of $4,797,700 (MMS Staff, 1985) or $16,640,436 in 2015 dollars (HBrothers, 2015). Total prospect cost included leased blocks 100 ($1,620,000), 101 ($4,731,000), 144 ($5,346,750), 145 ($4,797,700), 146 ($5,759,000), 188 ($2,679,900), and 189 ($420,000) of Lydonia Canyon. Total lease costs were $25,354,350 at Sale 42 (Dec 18, 1979) or $87,939,500 in 2015 dollars. MMS tract evaluation was MROV = $142,848 (MMS Staff, 1985). Total well costs for LC 145-1 were unavailable but are estimated to be $32.5 million in 2015 dollars (HBrothers, 2015) based on the number of drilling days (92) and the average cost per day for drilling in Georges Bank. The average cost per day was determined from the 4 wells that had cost data available.

1.7.4 Petroleum System Analysis

Magoon and Dow (1994) defined a petroleum system as "a natural system that encompasses a pod of active source rock and all related oil and gas and which includes all the geologic elements and processes that are essential if a hydrocarbon accumulation is to exist." Petroleum includes thermal or biogenic gas … or condensates, crude oils, and asphalts found in nature (Magoon and Dow, 1994).

Petroleum system elements are: source rock, reservoir rock, seal rock, and overburden rock (a thick enough rock column above the deepest source rock interval to result in burial sufficient for temperatures to initiate hydrocarbon generation). Our guidelines for source, reservoir, and seal elements are shown in italics in Table 5.

Petroleum system processes include trap formation and hydrocarbon generation–expulsion–migration–accumulation (Table 6), and preservation (modified after Magoon and Dow, 1994).

Timing is paramount in petroleum systems; *e.g.*, a reservoir in a sealed trap must exist when hydrocarbons are generated, expelled from the source rock, and most importantly, migrate into, become entrapped and subsequently retained in the trap (Magoon and Dow, 1994). Not all processes will occur in all areas; i.e., when there is no hydrocarbon generation and expulsion, there can be no migration or accumulation.

Geochemistry

Geochem Laboratories, Inc. conducted Rock-Eval pyrolysis, measuring T_{max} (a maturity indicator), S_1 (a measure of free hydrocarbons), and S_2 (a measure of hydrocarbons released upon heating and cracking of the kerogen), and S_3 (a measure of the amount of CO_2 created from the thermal breakdown of kerogen) (Peters and Cassa, 1994) on 75 samples from 760'–TD for the LC 145-1 well. Production index, a ratio of S_1 to S_1 plus S_2, hydrogen index (HI) ((S_2/TOC)x100), and oxygen index (OI) ((S_3/TOC)x100) were calculated and used in the geohistory models and to estimate cumulative hydrocarbon volumes. Pseudo van Krevelen (HI vs. OI) and S_2 vs. TOC diagrams were made to aid in the identification of the kerogen types.

Vitrinite reflectance (%R_o) was measured on 29 samples from a depth of 1750' to TD. %R_o is a maturity indicator, measuring under a microscope the percentage of incident light reflected from a polished surface of vitrinite (U.S. Dept. of Interior BLM, 2014). Geochemical analyses and geohistory modelling using BasinMod® place the early maturity oil generation (0.5%R_o) in the Late Jurassic Tithonian at 6,160'. Modelling shows that the main dry gas generation stage (1.3%R_o or >465^o C T_{max}) was not reached at TD, as confirmed by T_{max} measurements which reached a maximum of 446^o C. Modelling shows the main gas window would occur below the well TD, at a depth of 16,870' in the early Middle Jurassic (Geochem Laboratories Inc., 1982).

TOC (listed in present-day values) was measured for 75 samples at 90' intervals from 675'–14,440' with an average value of a 0.29% and a maximum value of 0.94% at 675'–760' (Geochem Laboratories Inc., 1982). For depths greater than the early mature oil stage at 6,160', the max TOC is 0.77% with values averaging just 0.13% from ~9500–TD (top of Oxfordian and older). Coupled with the low TOC in the well (Geochem Laboratories Inc., 1982) was the high percent of inert kerogen (Type IV). Supporting the low TOCs were the S_1 values, representing free hydrocarbons, which were also very low, ranging from 0 to 0.11 and averaging 0.01 (Geochem Laboratories Inc., 1982). S_1 values less than 0.05 are considered poor (Peters and Cassa, 1994). Only 11 of 75 hydrogen index values were above 50 mg HC/g TOC, with the highest in immature intervals. Values below this correspond to Type IV (inert) kerogen, which is not capable of producing hydrocarbons (Peters and Cassa, 1994).

Visual kerogen analysis (VKA) is microscopic observation of various kerogen types present in a sample with a percentage of each kerogen type estimated. Objectivity and consistency between samples is a priority for VKA and %R_o as both of these methodologies are inherently subjective. Geochem Laboratories, Inc. (1982) performed VKA that showed a mix of 4 kerogen types throughout much of the well. Pseudo van Krevelen and S_2 vs. TOC diagrams created from the Rock Eval data classified approximately two thirds of the organics into Type IV kerogen, and the balance into the gas-prone Type III kerogens. We believe the Rock-Eval data to be more accurate, determining the most significant aspect of kerogen characterization, their kinetic behavior under thermal stress.

Dembicki (Conoco, 1982c) states that an RFT sample at 9,178' contained both gas and formation water. The gas was thermogenic in origin based on:

1. the wet gas concentration (summation of the C2 and greater components) is greater than 5 percent, which indicates it could be a wet gas associated with liquid hydrocarbon generation
2. the carbon isotope ratio of the methane is in the range of thermogenic gas, too heavy for biogenic methane with a 13C value of -40.2 suggesting gas generation from marine source rock within the oil window
3. the presence of significant amounts of nitrogen, which is considered more characteristic of thermogenic rather than biogenic gas
4. gas chromatograph analysis of the formation water identified benzene and toluene, indicating contact with liquid hydrocarbons in the subsurface (Conoco, 1982c).

This matches BOEM's geohistory modeling, which shows the well never reached the main dry gas generation stage. How much of the inferred oil exists, whether it formed *in situ*, or its source rock if migrated into the well are unknown. The gas-prone kerogens seen in LC 145-1 would indicate either small quantities or migrated liquids. The low porosity and permeability conditions would make migration difficult.

LC 145-1 had the most geochemical data of the GBB industry wells, consistently displaying negative results. PI and T_{max} values reinforce the $\%R_o$ data, supporting maturity below the gas window at TD. Low S_1 and S_2 correspond to the low TOC. The low HI, as well as the HI to OI and the S_2 to TOC ratios, indicates the predominant kerogens were Type III (gas-prone) and Type IV (inert).

Exploration Implications

1. Very low TOC was encountered throughout the well, resulting in poor petroleum potential. Although the primary objective zones in the well were within the main oil generating window, because of the poor quality source rocks, modeling shows that only a few barrels of hydrocarbons/acre*ft would be generated with none expelled. Table 7 cites these deficiencies in the post-drill results section. The minor gas shows encountered appear to be *in situ*, or very near where the gas was generated. The seismic interpretation (Fig. 6) suggests that there are no major vertical cross-stratal migration conduits in the area of the well, nor do there appear to be significant carrier beds based on the low porosities and permeabilities encountered.
2. Reservoir development was poor. Porosities and permeabilities were variable. However, conventional cores and wireline log analysis determined both to be low in the targeted zones (Conoco Laboratories Inc., 1982a). The most reliable values come from the conventional cores and those average 3.72% for the porosity, and 0.03 mD permeability if the high permeability zone from 10,625'–10,635' is excluded. Permeabilities in this 10' vuggy limestone zone averaged 45 mD. Removing this interval for the porosity average reduces it to 2.96%.

Acknowledgements

The support of BOEM management and staff: R. Poling and M. Wilson are gratefully acknowledged. We are grateful to GeoSpec, a CGG company, for allowing the publication of their reprocessed, depth-converted, time-migrated seismic data and derivative maps produced by BOEM staff from this data. The assistance of J. Danford and M. Paton of GeoSpec is greatly appreciated.

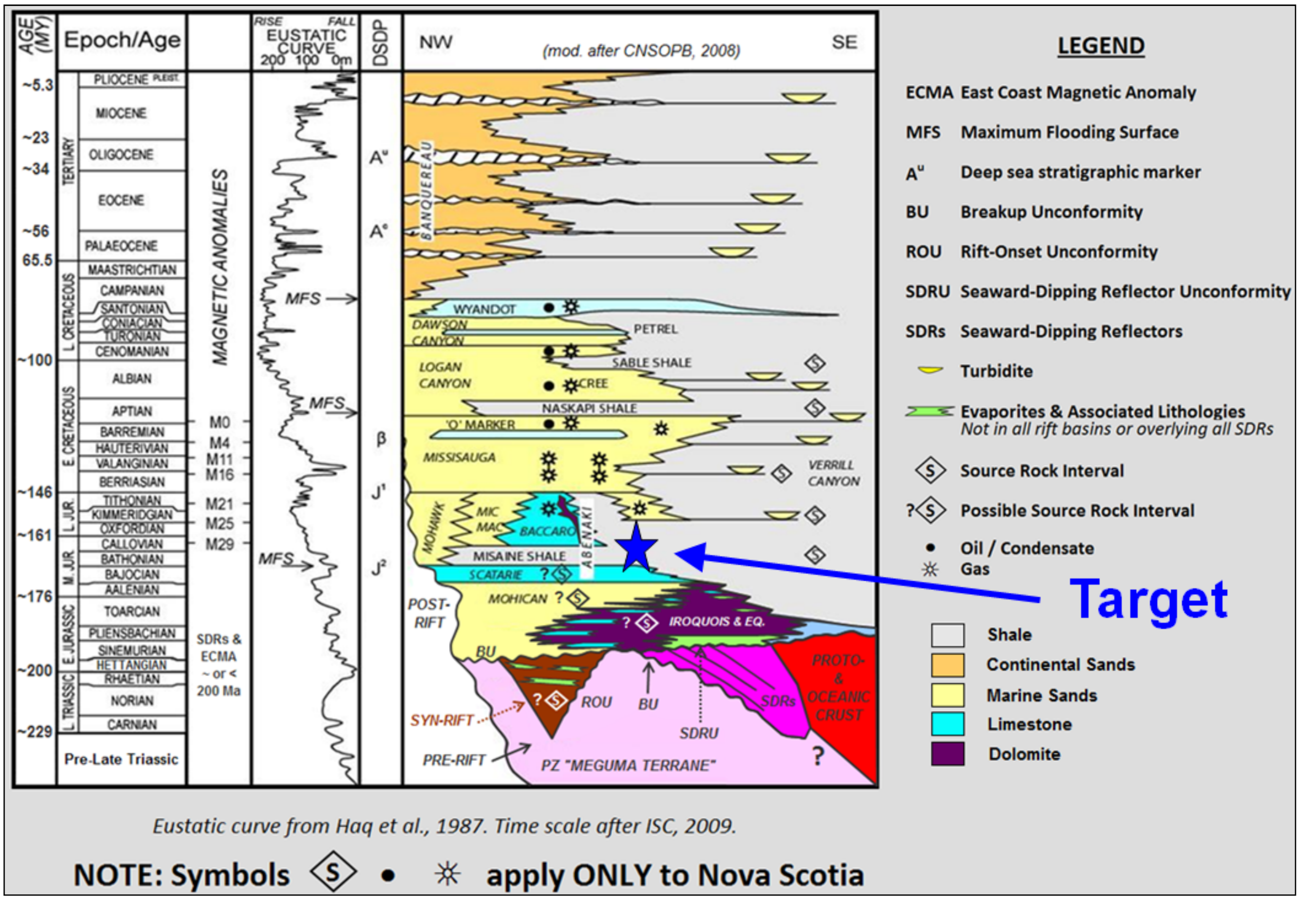

Figure 2. Stratigraphic chart showing the target interval for Conoco's LC 145-1.

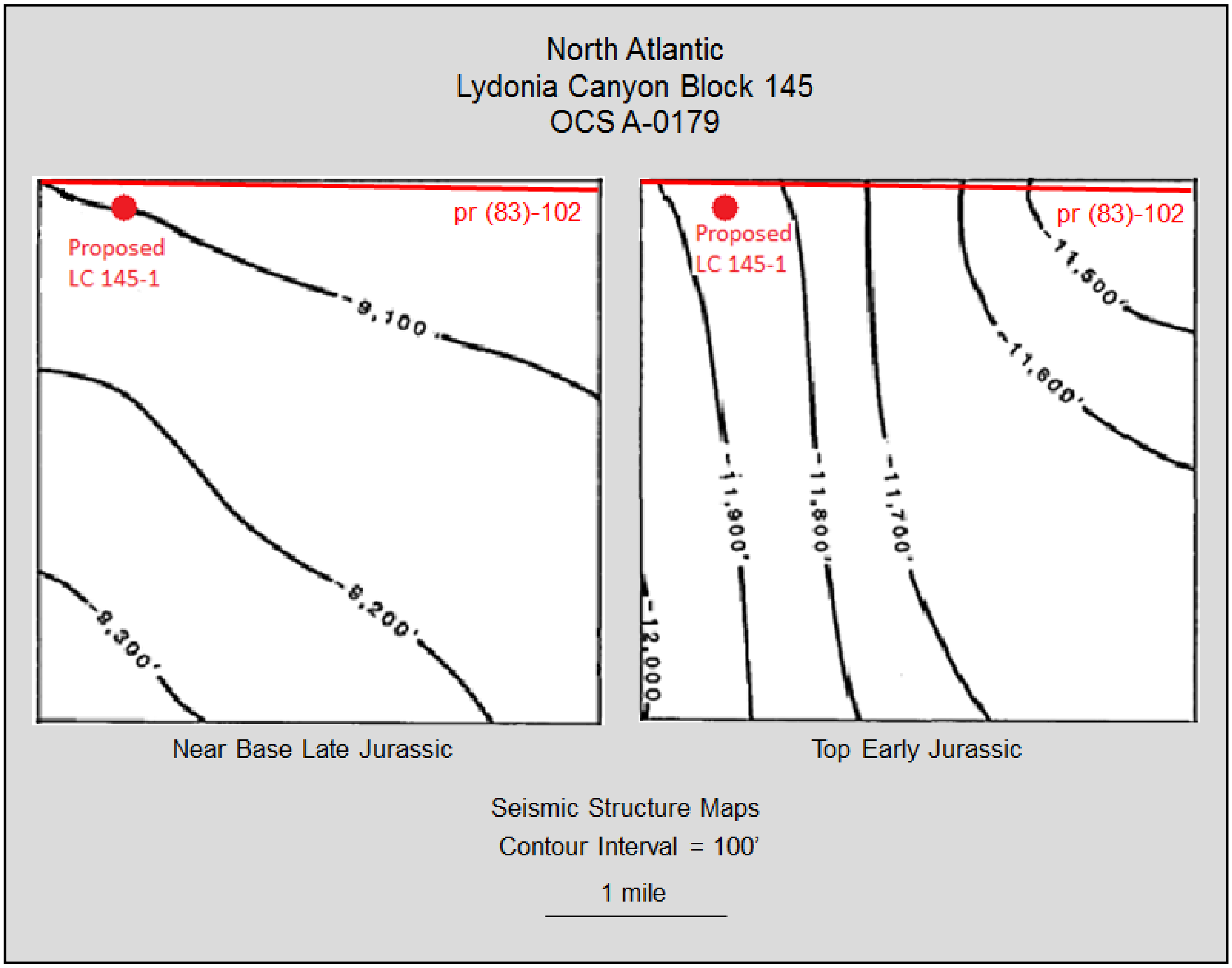

Figure 3. Structure maps covering block LC 145 of the 'Near Base Late Jurassic' and 'Top Early Jurassic' targets. Modified from Gulf Oil Corp's structure maps originally submitted in their exploration plan (Gulf Oil Corp, 1981), and resubmitted in Conoco's APD (Conoco, 1982b).

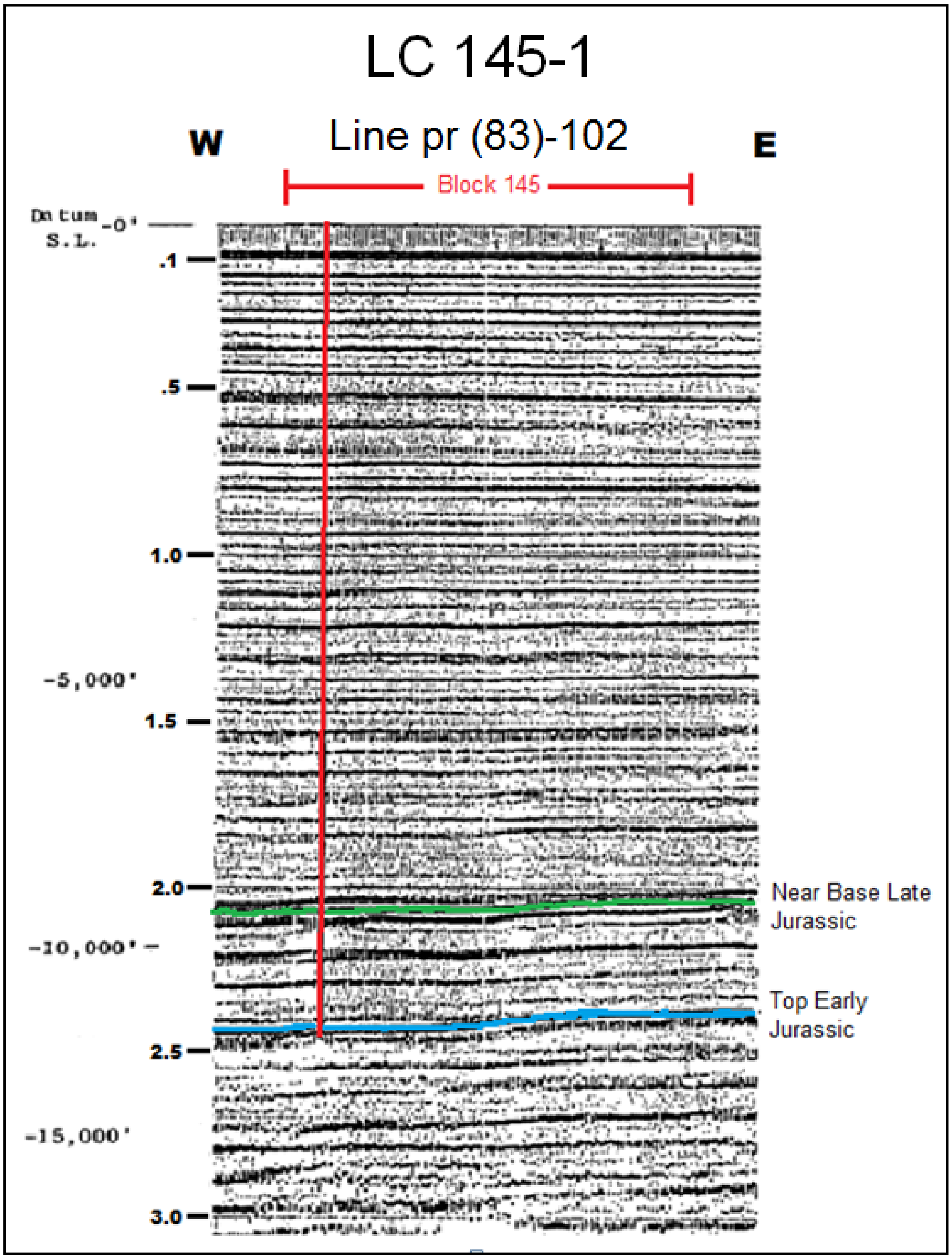

Figure 4. West-east dip line pr (83)-102 submitted as part of the APD (modified from Gulf Oil Corp, 1981; subsequently resubmitted by Conoco). Exploration targets are labeled on the seismic.

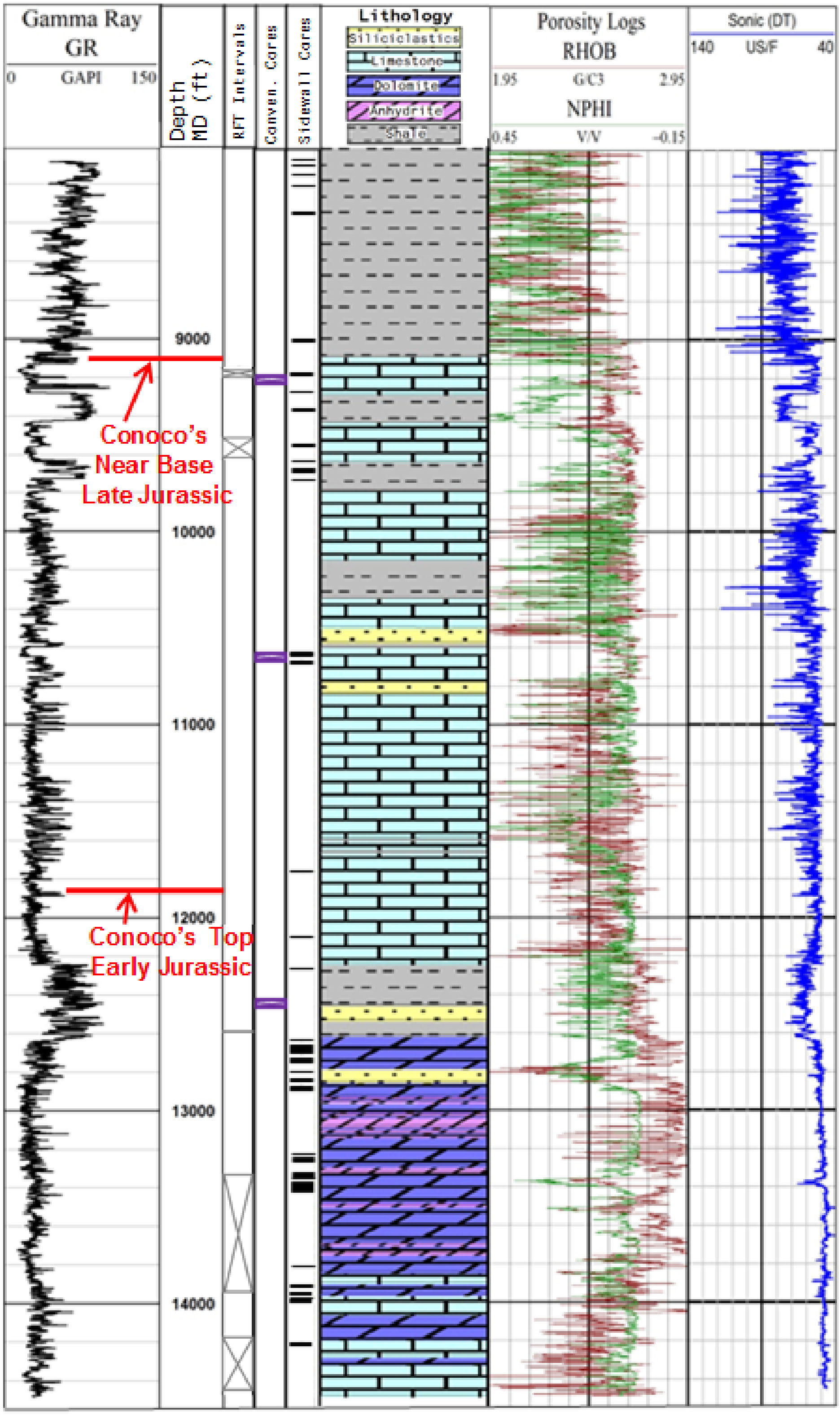

Figure 5. Objective zones for well LC 145-1 with interpreted lithologies based on mud logs, sidewall and conventional core descriptions, and a crossplot of neutron and density curves. Locations of repeat formation tests, conventional cores, and sidewall cores are also shown.

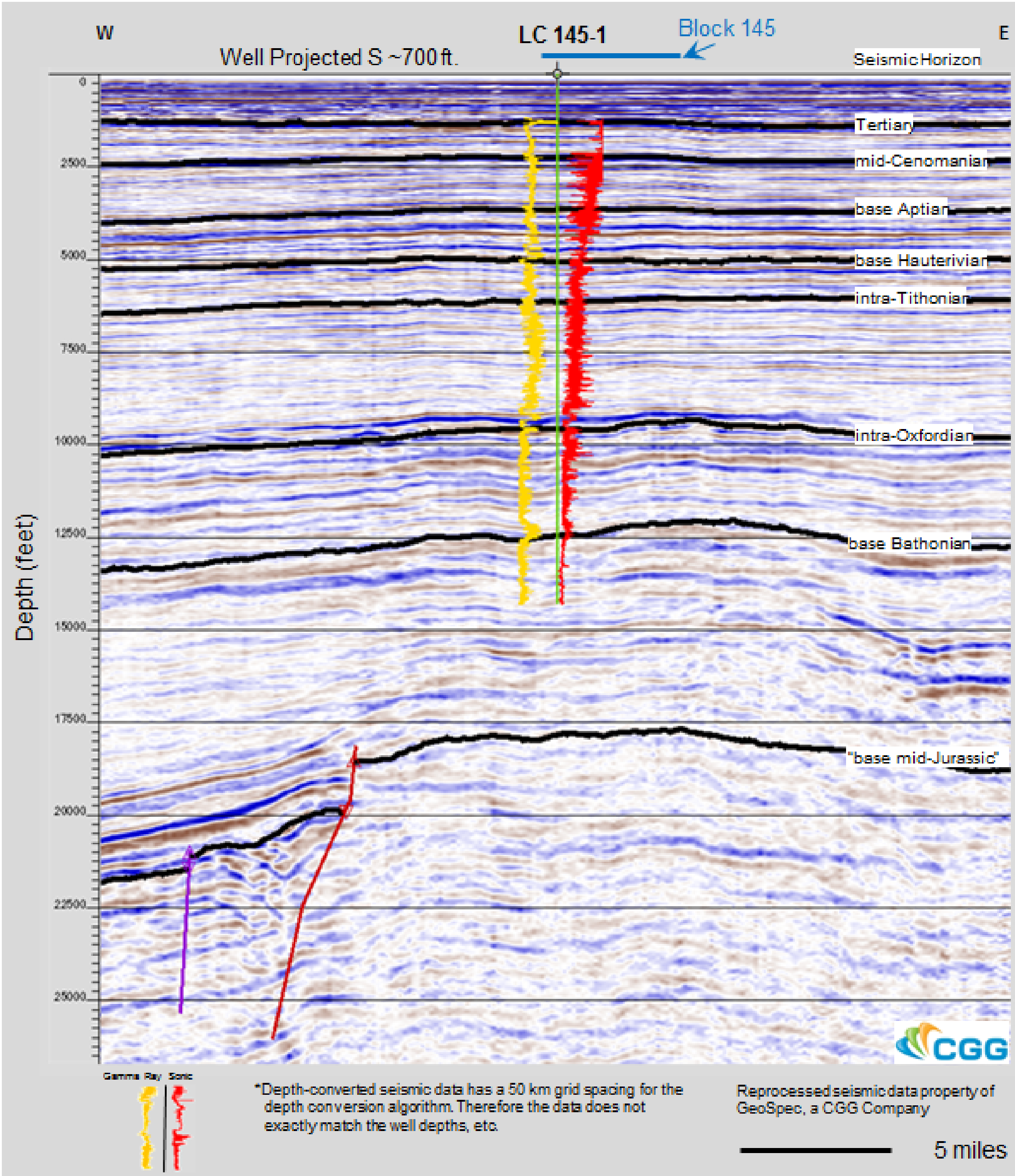

Figure 6. Our interpretation of the pr (83)-102 line showing the structural uplift and associated faulting to the west with interpreted SB horizons listed. Structure maps of the base Bathonian (SB2) and intra-Oxfordian (SB3) horizons are shown in Figures 7 and 8. Figure 9 is an isochore between intra-Tithonian (SB4) and "base mid-Jurassic" (SB1).

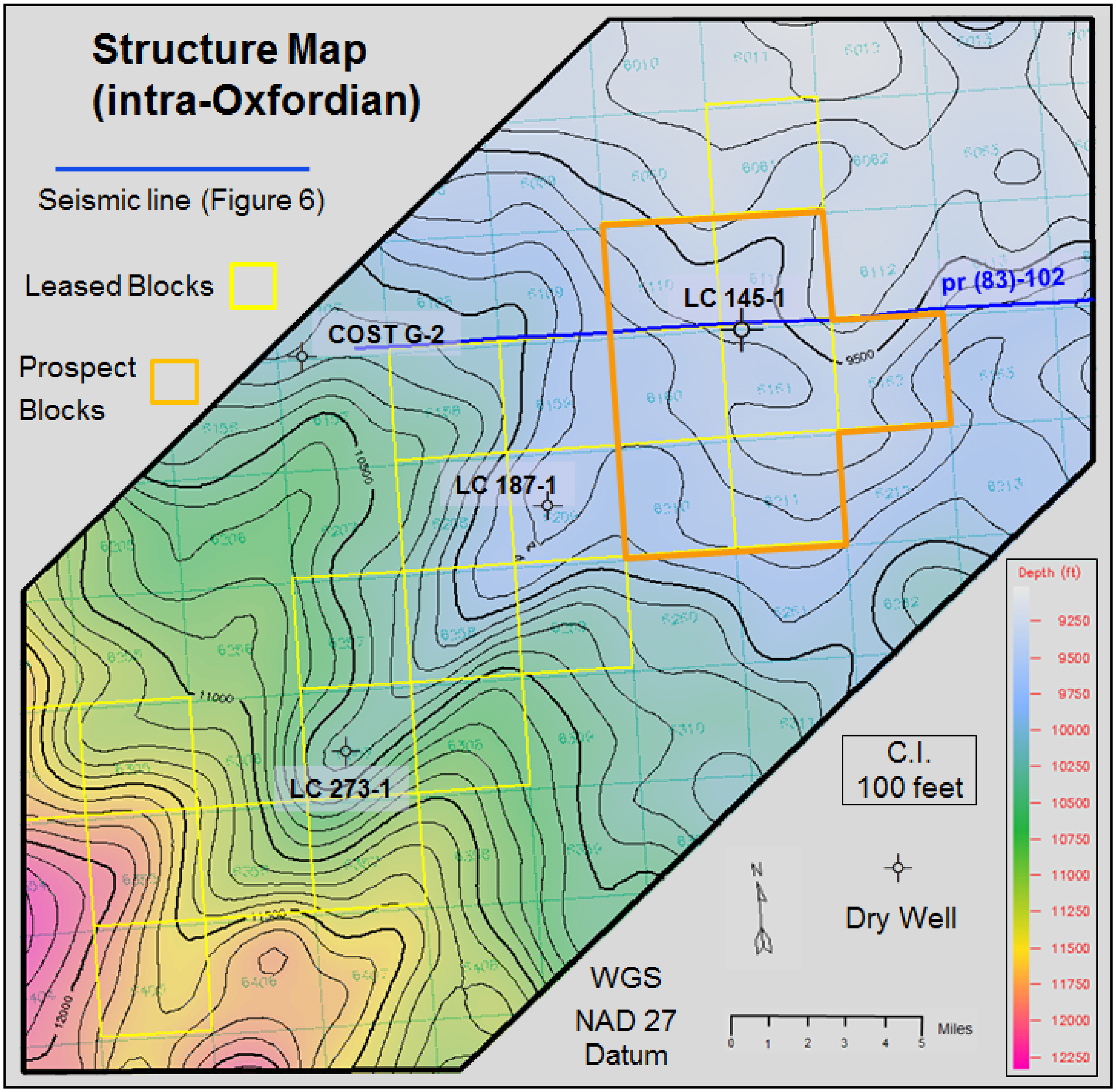

Figure 7. Structure map of intra-Oxfordian (SB3). Orange lines delineate the prospect LC 145-1 tested. Seismic line pr (83)-102 is shown in blue.

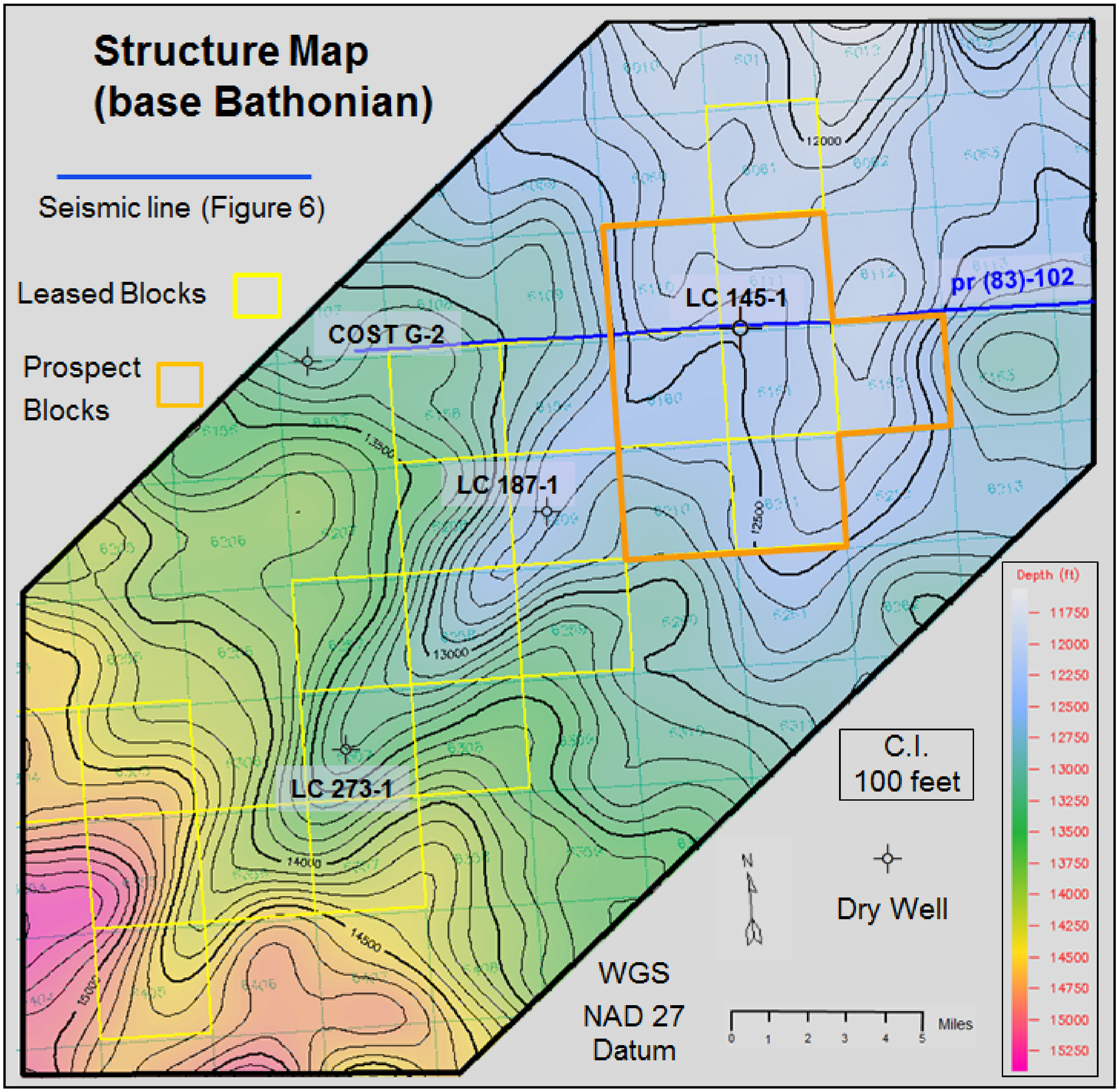

Figure 8. Structure map of base Bathonian (SB2). Orange lines delineate the prospect LC 145-1 tested. Seismic line pr (83)-102 is shown in blue.

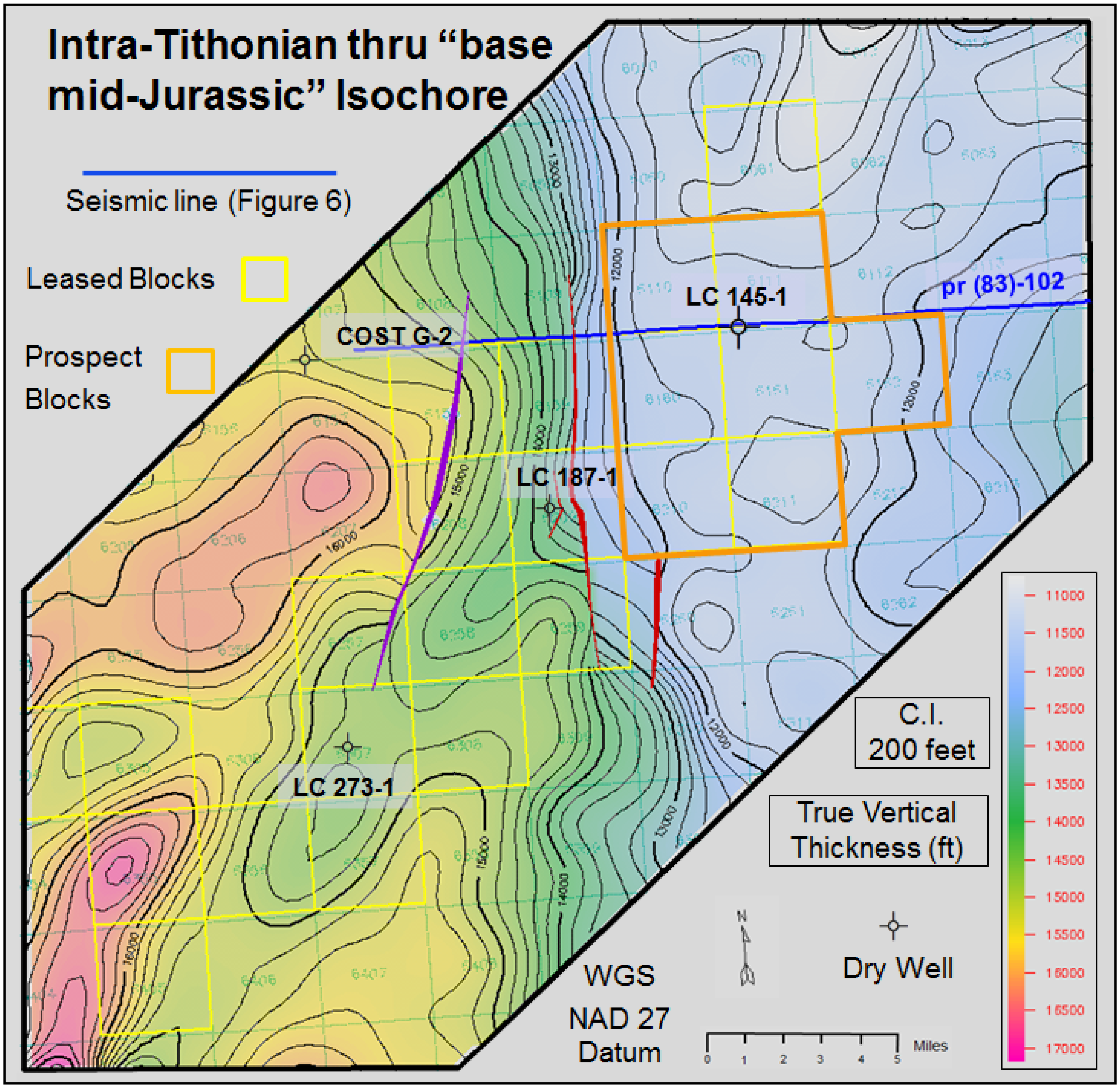

Figure 9. Isochore map from intra-Tithonian (SB4) to "base mid-Jurassic" (SB1). Orange lines delineate the prospect LC 145-1 tested. Seismic line pr (83)-102 is shown in blue.

Table 1. Wells drilled in Georges Bank Basin

Well	Date	Target	Actual
COST G-1	1977	n/a	n/a
COST G-2	1976	n/a	n/a
LC 133-1	1981	Callovian Reef	Volcanic Sequence
CO 975-1	1982	Bathonian porous shelf carbonate	Evaporite Lens
LC 410-1	1982	Jurassic Closure	Jurassic Closure poor porosity
LC 312-1	1982	Callovian Reef	"Tite" micritic Limestone
LC 187-1	1982	Jurassic age Limestones and Dolomites	Reservoir of poor quality
LC 145-1	**1982**	**Jurassic Porous Shelf edge Calcarenites and Jurassic Carbonates**	**"Tite" micritic Limestones**
LC 273-1	1982	Four way closure, Jurassic oölitic and bioclastic limestones	"Tite" micritic Limestones
LC 357-1	1982	Simple structural closure in Limestone, Dolomite, and anhydrite	"Tite" micritic Limestones

Table 2 Conventional core data. Dominate lithology for the section is identified along with the amount of retrieved core in parenthesis. Averages are in parenthesis behind the range of measured values.

Interval	Lithology	Porosity (%)	Permeability (mD)	Gas Bulk (%)
9191-9227'	Limestone (36')	1.5-6.1 (2.9)	<0.01-0.13 (0.04)	<5%
10622-10652'	Limestone (30')	2.6-13.4 (7.7)	<0.01-172.0 (19.0)	0.6-9.5%
12419-12448'	Limey Silt (29')	1.6-3.3 (2.4)	<0.01-0.23 (0.09)	<5%

Table 3. Data from Conoco's biostratigraphic report.

Samples	Interval Size	Range	Measured/Examined
461 ditch cuttings	30'	675'–14,500'	Foraminifers microfossils
138 cuttings	90'	675'–14,500'	Palynology

Table 4. Formation names, ages, and tops determined via wireline log and seismic correlation to wells with data from GeoSpec. Depositional environment based on IBI's paleontological report. Lithologic descriptions are made from our analysis of mud and wireline logs, sidewall and conventional core descriptions.

Depth (tops)	Age	Formation/Unit: Lithology	Depositional Environment
600	Miocene to Campanian	Unknown	Middle shelf (~300'), mud dominated
1415	Campanian to Cenomanian	Dawson Canyon Fm.: Some sandstone in the top of formation underlain with fossiliferous shale	Middle shelf (~300'), mud dominated
2230	Cenomanian to Barremian	Logan Canyon Fm.: Interbedded sandstone, siltstone, and shale with lignite and traces of pyrite, glauconite, and fossil fragments	Shallow water (~50'–100'), mixed mud and siliciclastic dominated shelf
3735	Barremian to Berriasian	Mississauga: Sandstone and limestone dominate with shale, some siltstone and occasional lignite, fossils, and pyrite	Shallow water (~50'–100'), mixed siliciclastic and carbonate dominated shelf
4930	Berriasian to Tithonian	Roseway Unit: Limestone dominate with some sandstone, siltstone, and shale along with traces of pyrite and glauconite,	Shallow water (~50'–100'), mixed siliciclastic and carbonate dominated shelf
6340	Tithonian-Kimmeridgian	Abenaki Fm.: Limestone interbedded with shale and some siltstone. Minor amounts of sandstone and trace pyrite.	Shallow water (~50'–100'), carbonate dominated shelf
7035	Kimmeridgian	Mic Mac-Mohawk Fms.: Interbedded sandstones, siltstones, and shales with limestone in the upper and lower parts of the formation. Traces of pyrite throughout and localized traces of glauconite.	Shallow water (~100), mixed siliciclastic and carbonate dominated shelf
8845	Kimmeridgian-Callovian	Abenaki Fm.: Top half is interbedded limestone, siliclastics, and shale while the rest of formation is predominately limestone. Fossil fragments in the top portion and anhydrite in the lower. Traces of pyrite and lignite throughout.	Shallow water (~50 –100'), mixed siliciclastic and carbonate dominated shelf
12245	Bathonian-Early Middle Jurassic*	Mohican Fm.: Interbedded limestone, sandstone, silt, and shale with traces of anhydrite and pyrite	Shallow water (~25'–100'), mixed siliciclastic and carbonate dominated shelf
12645	Early Middle Jurassic*	Iroquois Fm.: Top 50' is sandstone which fades out over the next 300' as carbonates become dominate. The rest of the formation is dolomite with interbedded limestone and anhydrite. Traces of siltstone and pyrite throughout.	Carbonate shelf and tidal flat, sabkha. Restricted shallow marine

*Fauna are interpreted as being reworked. Age interpretation considered unreliable.

Table 5. Petroleum System Elements

Element	LC 273-1 Lithology
Source rock *(>1% TOC)* *However, an effective source rock has ~2% TOC*	Not seen in the well (average TOC 0.3%, max 0.9%)
Reservoir rock *(>10 % φ >1 mD k)*	K sandstones and J sandstones interbedded within carbonates that dominate J. J limestones are generally poor reservoirs.
Seal rock *(10^{-3} mD k)*	Shale, impermeable limestone, anhydrite
Overburden rock	Early maturity for oil at 6,160’ (%R_o 0.5) Main dry gas generation at 16,870’ (%R_o 1.3)

Table 6. Petroleum System Processes

Onset hydrocarbon generation	6,160’ for early maturity of oil (%R_o 0.5) and 16,870’ for main dry gas generation (%R_o 1.3) based on modelling incorporating %R_o data from the well.
Expulsion	Strata in the well contain insufficient TOC (< 1%) to generate and expel hydrocarbons. (Katz, 2012). There are no significant shows. Modeling using BasinMod® 2012 suggests that the limited volumes of hydrocarbons generated are retained in the “source rock” (*in situ*).

Table 7. LC 145-1 Target Summary

Pre-Drill Interpretation	
Target	~9,100 – 11,850’ (Conoco Inc., 1982b)
Trap Type	Structural-Stratigraphic
Hydrocarbon Expected	Oil and gas
Post-Drill Results	
Target Interval	At ~5,400’, MD Jurassic carbonates were encountered. Insufficient TOC for hydrocarbon generation–expulsion–migration–accumulation was encountered to TD of 14,500’
Hydrocarbon Shows	There were no reported oil shows and no significant gas shows

References:

Conoco Inc., 1982a. Well Completion Report, Well #1, OCS A-0179, Block 145, NK 19-12 (Lydonia Canyon), 2 p. (available at https://www.data.boem.gov/homepg/data_center/other/WebStore/master.asp)

Conoco Inc., 1982b. Application for Permit to Drill, Well #1, OCS A-0179, Block 145, NK 19-12 (Lydonia Canyon), 177 p. (available at https://www.data.boem.gov/homepg/data_center/other/WebStore/master.asp)

Conoco Inc., 1982c. Formation Test Report, Well #1, OCS A-0179, Block 145, NK 19-12 (Lydonia Canyon), Analysis of Hydrocarbons in the RFT Sample from the Conoco Lydonia Canyon Blk. 145 No. 1 Well, Offshore Massachusetts, 6 p. (available at https://www.data.boem.gov/homepg/data_center/other/WebStore/master.asp)

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