Chapter 2

Jurassic-Cretaceous Composite Total Petroleum System And Geologic Models For Oil And Gas Assessment Of The North Cuba Basin, Cuba

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By Christopher J. Schenk

Chapter 2 of

Jurassic-Cretaceous Composite Total Petroleum System and Geologic Assessment of Oil and Gas Resources of the North Cuba Basin, Cuba

By U.S. Geological Survey North Cuba Basin Assessment Team

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Jurassic-Cretaceous Composite Total Petroleum System and geologic models for oil and gas assessment of the North Cuba Basin, Cuba

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Abstract

Petroleum generation in the North Cuba Basin is primarily the result of thrust loading of Jurassic and Cretaceous source rocks during formation of the North Cuba fold and thrust belt in the Late Cretaceous to Paleogene. The fold and thrust belt formed as Cuban arc-forearc rocks along the leading edge of the Caribbean plate translated northward during the opening of the Yucatan Basin and collided with the passive margin of southern North America in the Paleogene. Petroleum fluids generated during thrust loading migrated vertically into complex structures in the fold and thrust belt, into structures in the foreland basin, and possibly into carbonate reservoirs along the margins of the Yucatan and Bahama carbonate platforms. The U.S. Geological Survey defined a Jurassic-Cretaceous Composite Total Petroleum System (TPS) and three assessment units (AU)–North Cuba Fold and Thrust Belt AU, North Cuba Foreland Basin AU, and the North Cuba Platform Margin Carbonate AU-within this TPS based mainly on structure and reservoir type. There is considerable geologic uncertainty as to the extent of petroleum migration that might have occurred within this TPS to form potential petroleum accumulations. Taking this geologic uncertainty into account, especially in the offshore area, the mean volume of undiscovered oil in the composite TPS of the North Cuba Basin is estimated to be 4.6 billion barrels of oil (BBO), and the mean ranges from an F95 probability of 1 BBO to an F5 probability of 9 BBO. The mean volume of undiscovered gas is about 9.8 trillion cubic feet of gas (TCFG), and of this total, 8.6 TCFG is associated with oil fields, and about 1.2 TCFG is estimated to be gas in nonassociated gas fields in the North Cuba Foreland Basin AU.

Introduction

The purpose of this paper is to present an assessment of the undiscovered oil and gas resources in the North Cuba Basin (fig. 1) and to discuss the geologic uncertainties inherent in the assessment. This assessment was completed as part of the U.S. Geological Survey World Energy Project in which undiscovered oil and gas resources were assessed in 128 basins worldwide (U.S. Geological Survey World Energy Assessment Team, 2000).

The North Cuba Basin is a geologically complex area and includes several disparate geologic entities, including the Yucatan carbonate platform, the Florida carbonate platform, the southeastern Gulf of Mexico, and the fold and thrust belt of Cuba (fig. 2). The tectonic evolution of this area includes counterclockwise movement of the Yucatan Platform, the opening of the Gulf of Mexico oceanic basin, and the formation of the Cuban archipelago. The tectonic history had a direct bearing on the petroleum systems in the North Cuba Basin.

The onshore part of the North Cuba Basin has a long history of petroleum exploration and production. The first field, Motembo, was discovered onshore in northwestern Cuba in 1881, and Motembo remains the only condensate field in Cuba. More than 20 oil fields have been discovered in Cuba since then, mostly in the North Cuba Basin (Oil and Gas Journal, 1993) (fig. 3; table 1). Although most of the onshore oil fields are small, shallow, and contain heavy oil (Petzet, 2000), the fact that oil exists there is strong evidence that one or more petroleum systems either are or were active in the subsurface of the northwestern part of Cuba. Based on oil production of onshore Cuba and the knowledge gained from several recent geologic and geochemical studies, the offshore is interpreted to have potential for undiscovered oil and gas resources, and was the focus of the present study.

Detailed geological and geochemical investigations by Navarrete-Reyes and others (1994), Lopez-Quintero and others (1994), Moretti and others (2003a, b), and Magnier and others (2004) provided much basic oil and gas data and background information that significantly aided this oil and gas assessment.

Geological Evolution Of The Northern Caribbean Area

The geology of the Caribbean area in general and Cuba in particular is complex, and many decades of geologic

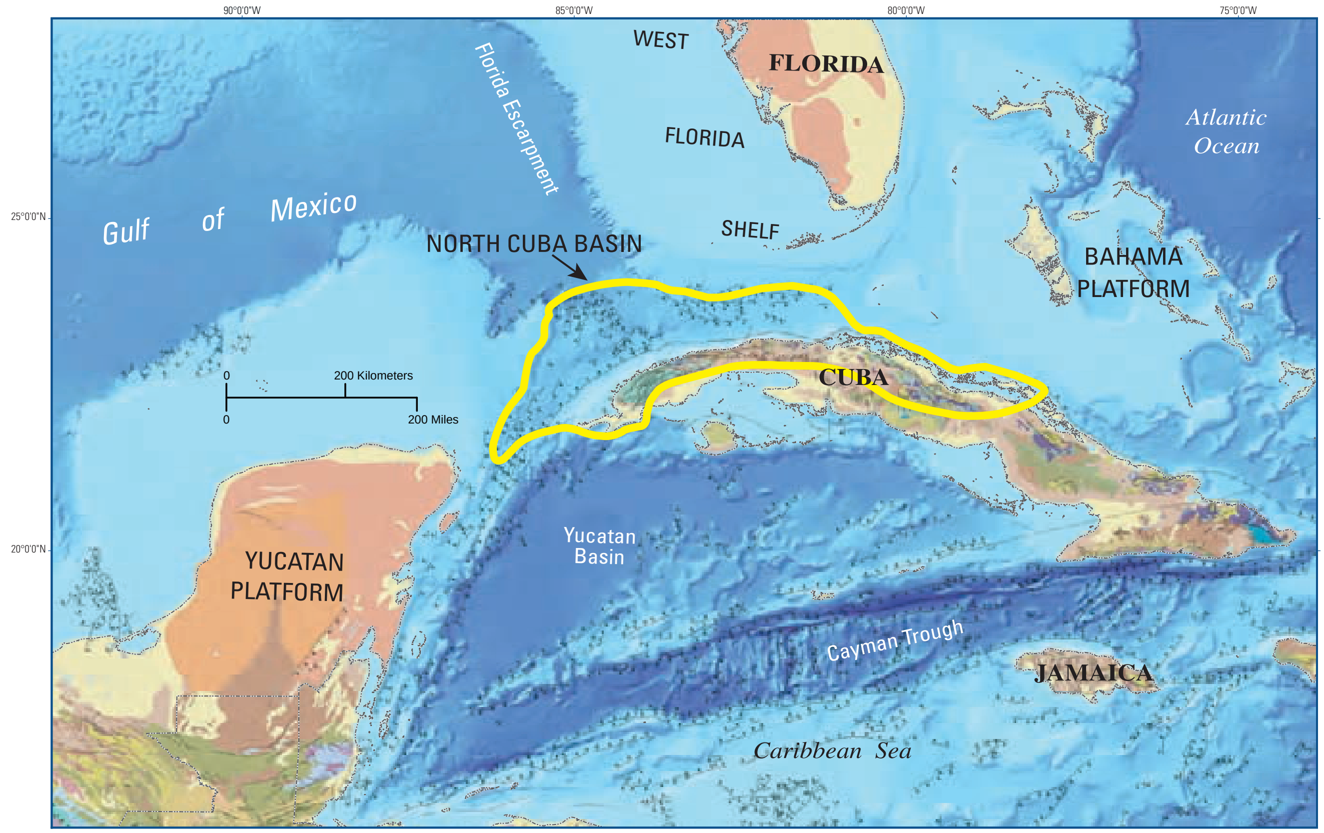

Figure 1. Locations of Cuba, Yucatan Platform, Yucatan Basin, Florida, Florida Escarpment, West Florida Shelf, Bahama Platform, and the general bathymetry of parts of the Gulf of Mexico, Yucatan Basin, Cayman Trough, Caribbean Sea, and Atlantic Ocean. Jurassic-Cretaceous Composite TPS shown by yellow line. North Cuba Basin boundary is same as composite TPS boundary in this study. Faults are shown as dark green lines; ball and bar on downthrown side of fault (after French and Schenk, 2004).

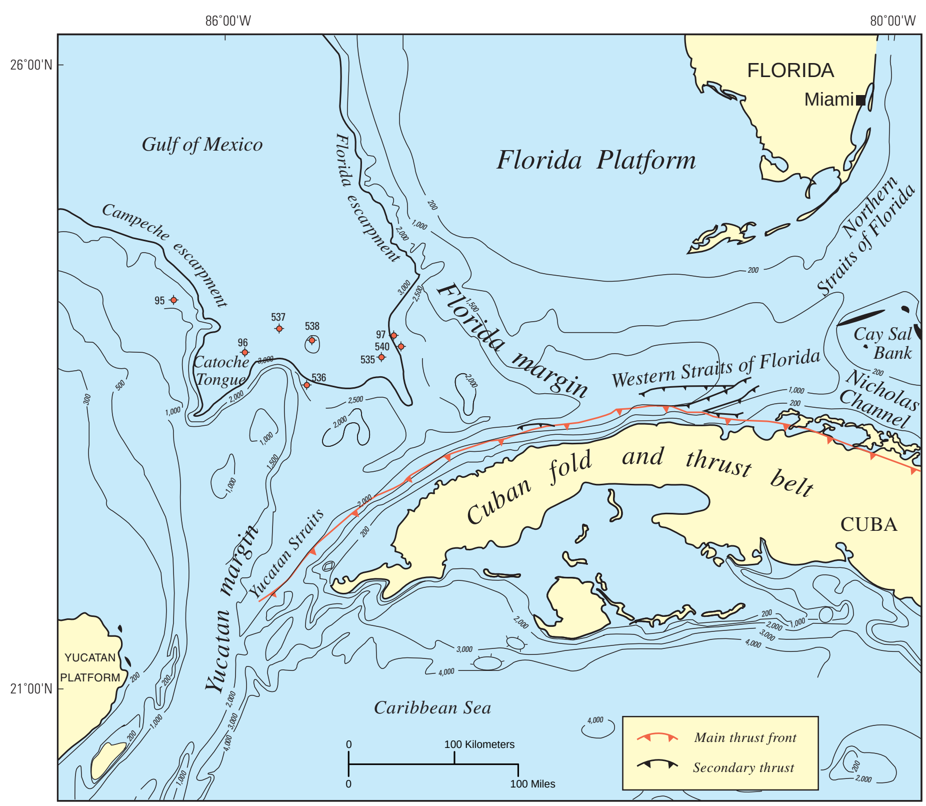

Figure 2. Physiographic features of the northwestern Cuba and the southeastern Gulf of Mexico area. Several Deep Sea Drilling Project (DSDP) wells are shown in red symbols (from Cubapetroleo, 2002).

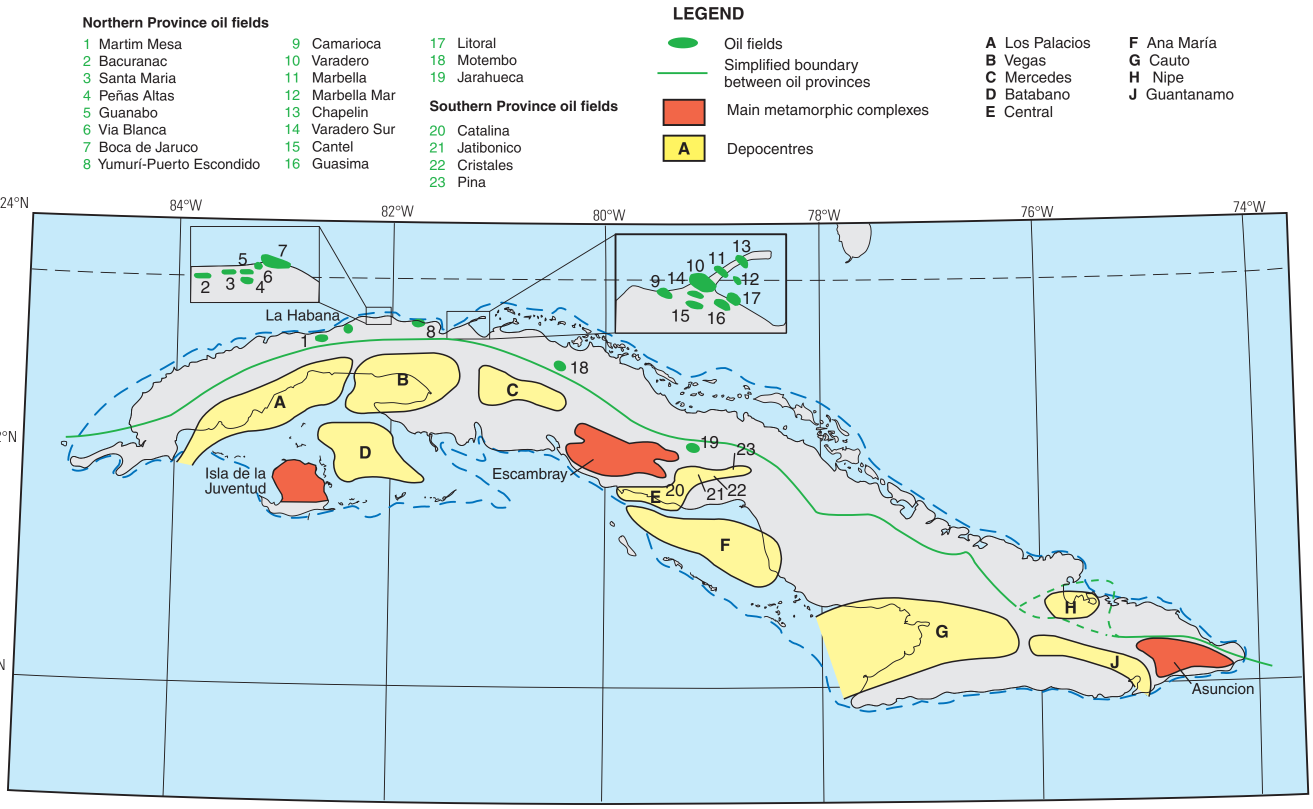

Figure 3. Locations of onshore oil fields of Cuba; most oil fields are in northwestern Cuba in the North Cuba Basin (from Cubapetroleo, 2002).

Table 1. Oil fields of the onshore North Cuba Basin; North Cuba Fold and Thrust Belt Assessment Unit.

[AVG, average; - -, no data.]

Field Name	Discovery Date	Tectonic-Stratigraphic Unit	API° (AVG)	API° (RANGE)	SULFUR (AVG)	SULFUR (RANGE)	Cumulative Production (To 1993) (Barrels x 1,000)	Oil in Place (Barrels x 1,000)
Motembo	1881	Zaza	61	56.2 - 62.3	0.00	- -	5,280	- -
Bacuranao	1914	Zaza	24	15.9 - 25.2	1.04	1.21 - 2.01	- -	- -
Jarahueca	1943	Zaza	38	- -	0.24	- -	1,659	- -
Penas Atlas	1954	Zaza	10	- -	2.94	- -	- -	- -
Santa Maria	1954	Zaza	22	- -	2.54	- -	- -	- -
Guanabo	1956	Zaza	11	- -	2.94	- -	1,767	17,000
Via Blanca	1968	Placetas	20	- -	2.78	- -	- -	-
Boca de Jaruco	1968	Placetas	17	10.0 - 44.3	1.49	0.33 - 9.2	23,188	1,023,000
Varadero	1969	Placetas	22	8.8 - 15.9	7.29	1.67 - 9.29	19,687	957,000
Camarioca	1971	Zaza	32	- -	0.18	- -	1,159	15,710
Chapelin	1971	Camajuani	- -	11.1 - 16.8	- -	5.64 - 7.11	41	6,650
Yumuri	1971	Placetas	16	- -	5.62	- -	117	29,100
Varadero Sur	1974	Placetas	20	- -	3.08	- -	1,280	60,000
Guasima	1974	Placetas	10	- -	4.66	- -	1,959	67,700
Marbella	1975	Zaza, Placetas	- -	- -	- -	- -	- -	- -
Cantel	1978	Camajuani	11	9.3 - 24.7	1.53	- -	7,411	75,000
Marbella Mar	1989	Placetas	30	- -	- -	0.22 - 3.72	- -	- -
Martin Mesa	1989	Placetas	19	9.3 - 36.7	1.49	- -	83	- -
Litoral	1990	Placetas	27	- -	- -	- -	- -	- -
Boca de Jaruco II	1990	- -	- -	- -	- -	- -	- -	- -
Faustino	2002	- -	- -	- -	- -	- -	- -	- -
Majaguiller	- -	- -	- -	- -	- -	- -	- -	- -
Cupey	- -	- -	- -	- -	- -	- -	- -	- -
Rio Del Media I	- -	- -	43	- -	0.09	- -	- -	- -
Puerto Esperanza	- -	- -	30	- -	0.27	- -	- -	- -
Madruga	- -	- -	- -	- -	- -	- -	- -	- -
Cruz Verde	- -	Zaza	- -	- -	- -	- -	- -	- -
Puerto Escondido	- -	- -	- -	- -	- -	- -	- -	- -

investigations have pieced together the main elements of the geologic evolution of Cuba, the Gulf of Mexico Basin, and the proto-Caribbean oceanic basin (Pardo, 1975; Lewis and Draper, 1990; Pindell and Barrett, 1990; Hempton and Barros, 1993; Pindell, 1993, 1994; Piotrowska, 1993; Draper and Barros, 1994; Iturralde-Vinent, 1994; Schlager and others, 1984; Gordon and others, 1997; Meschede and Frisch, 1998; Kerr and others, 1999; Pszczolkowski, 1999; Cobiella-Reguera, 2000; Pindell and Kennan, 2001, 2003; Pszczolkowski and Myczynski, 2003; Pindell and others, 2005; Iturralde-Vinent, 2006; Fillon, 2007). From the earliest studies the geology of Cuba was recognized as a series of north-verging thrust-fault-bounded tectonostratigraphic units (TSU), and the geologic definition of many TSUs was the focus of many previous investigations (figs. 4, 5). Eventually, tectonic studies in Cuba and in the northern Caribbean placed these TSUs in a framework of modern tectonic theory (Pindell and Kennan, 2001, 2003; Pindell and others, 2005). Detailed work demonstrated that the TSUs were the product of the collision between shelf, slope, and basinal sediments of the Mesozoic passive margin of the Yucatan and Bahama platforms and the arc-forearc rocks of the leading edge of the Pacific-derived Caribbean Plate as the Yucatan Basin opened in the Paleogene (Pindell and others, 2005). The stratigraphy of Cuba is complex, and many stratigraphic studies reflect the stacked thrust sheets produced during plate collision (fig. 6). However, the general stratigraphy of many TSUs has been interpreted and restored, documenting general stratigraphic relations (fig. 7).

Major events in the geologic history of northwestern Cuba include: (1) rifting between North America, South America, and Africa in Late Triassic-Early Jurassic time; (2) the tectonic evolution and passive-margin sedimentary history of the southeast Gulf of Mexico; (3) the development of the proto-Caribbean ocean basin and its passive margin; (4) movement of the Caribbean plate since the Early Cretaceous; and (5) Paleogene development of the Yucatan Basin and resultant collision and suturing of allochthonous Cuba terranes with the passive margin of the Bahama Platform. These events will be described briefly as each relates to the development of petroleum systems in the northwestern part of Cuba. The tectonic evolution of the Caribbean, especially the origin of the Caribbean plate, is somewhat controversial and is not the primary subject of this report.

Late Triassic to Middle Jurassic Rifting

The continents of North America, South America, and Africa composed the supercontinent of Pangea in the late Paleozoic and Triassic time (Salvador, 1991). In the Late Triassic, rifting began between North America and Africa and then between North and South America. Rifting continued through the Early and Middle Jurassic (Callovian), forming stretched or attenuated continental crust between the diverging continents (Marton and Buffler, 1993; 1994). During rifting, the extensional regime resulted in the formation of graben and half-graben structures in many areas of stretched continental crust, and these structures were filled with typical synrift sedimentary facies. The rift-related structures formed in the area underlain by continental crust in the northwestern part of offshore Cuba, and rift structures underlie part of the Bahama Platform (Sheridan and others, 1983; Ladd and Sheridan, 1987).

Facies of the rift-related grabens and half grabens include coarse red clastics, marine clastics, marine mudstones, and evaporites. These strata have been described from exposures on Cuba as the San Cayetano Formation (Haczewski, 1976) and as the Eagle Mills Formation from the subsurface of the northern Gulf Coast (Salvador, 1991). The synrift San Cayetano Formation might contain petroleum source rocks.

As rifting waned in the Middle Jurassic, evaporitic conditions within the extensional province resulted in the deposition of widespread evaporites (halite and anhydrite)

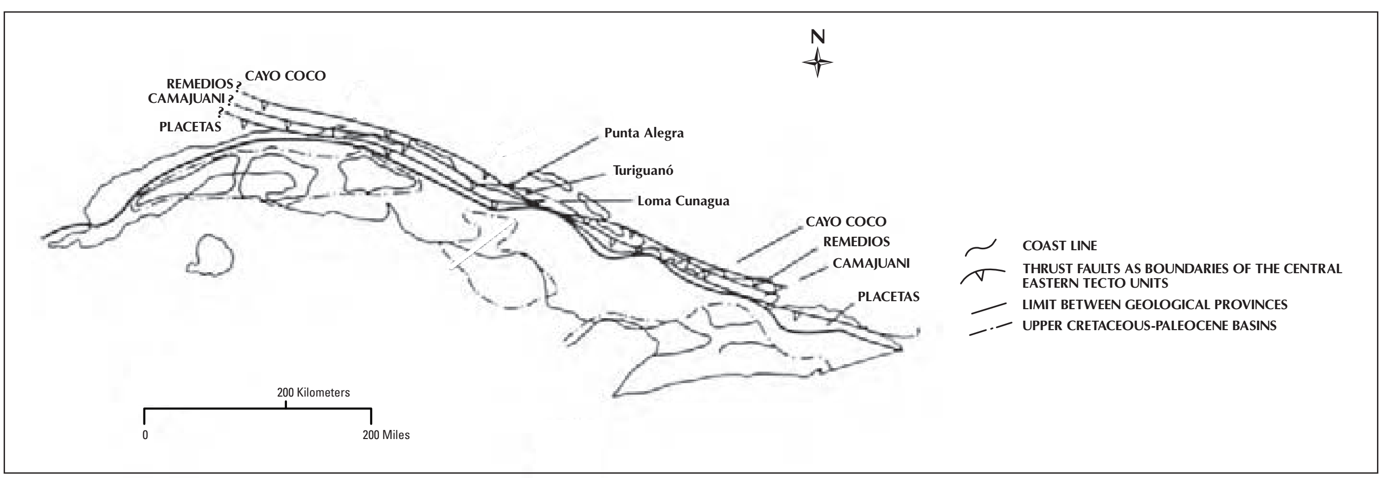

Figure 4. An interpretation of tectonostratigraphic units (TSU) of northern Cuba. TSUs are north-verging thrust-fault-bounded rock units that formed mainly as a result of the collision between Cuba and the passive margin of the Bahama Platform during the Paleogene (from Echevarria-Rodriguez and others, 1991)

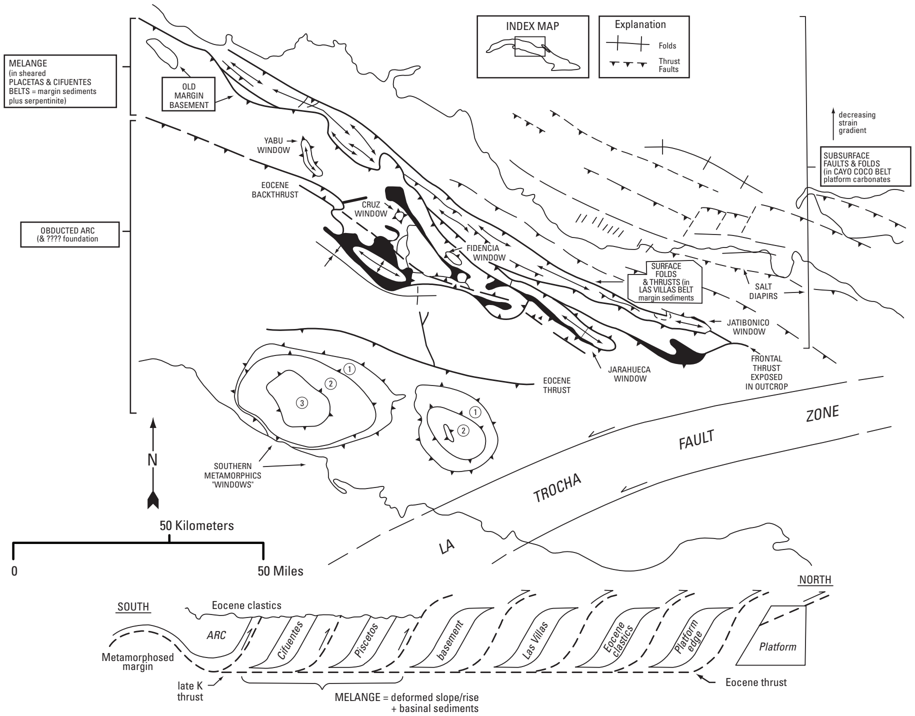

Figure 5. Map and diagrammatic cross section showing general positions of tectonostratigraphic units (TSU) of central Cuba. The TSUs have been studied and named across Cuba (from Hempton and Barros, 1993).

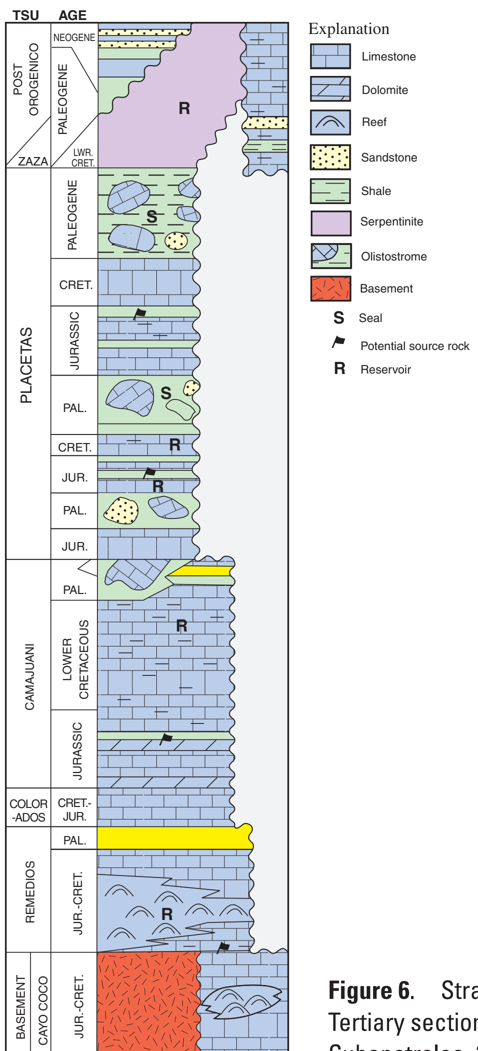

Figure 6. Stratigraphic column showing thrust repetitions in the Jurassic through Tertiary section in the Cuban fold and thrust belt in northern Cuba (modified from Cubapetroleo, 2002).

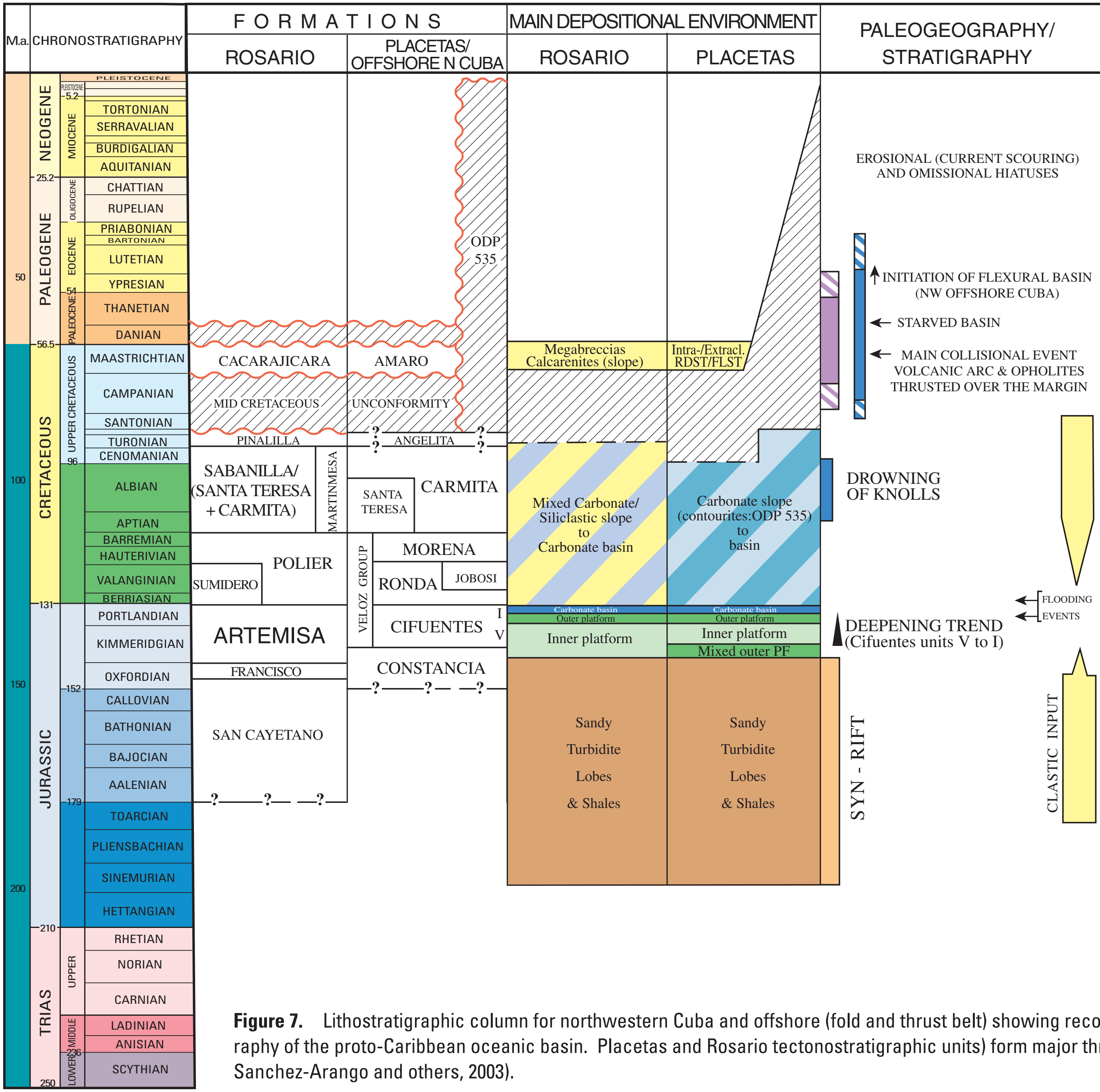

Figure 7. Lithostratigraphic column for northwestern Cuba and offshore (fold and thrust belt) showing reconstructed stratigraphy of the proto-Caribbean oceanic basin. Placetas and Rosario tectonostratigraphic units) form major thrust sheets (from Sanchez-Arango and others, 2003).

known as the Louann Salt in the northern part of the Gulf of Mexico and the Campeche Salt in the southern part. Evaporites also were deposited in the Bahama area (Walles, 1993), but these evaporites are not stratigraphically connected to the evaporites in the Gulf (Iturralde-Vinent, 2003). As rifting continued, the continental crust was stretched to the point where individual crustal blocks were mobilized, and sea-floor spreading commenced in the central part of the Gulf of Mexico as the Yucatan crustal block began to rotate counterclockwise. The rift-related structures formed during this time might have their own source rocks, reservoirs, and traps (Magnier and others, 2004).

Opening of the Gulf of Mexico In the Late Jurassic

In Callovian and possibly into Oxfordian time, the Yucatan crustal block began to rotate counterclockwise from its pre-rift position to its present configuration (fig. 8). The Yucatan block rotated about a hypothetical pole in Florida (Pindell, 1993), and rotated along a western transform margin in Mexico known as the Tamaulipas fault system. In the process, sea-floor spreading formed oceanic crust that floors the central part of the Gulf of Mexico. The spreading also resulted in the separation of the Callovian salt into two accumulations—the northern Louann Salt and the southern Campeche Salt. Thinner salt accumulations might exist to the east in the northwestern Cuba area. In about Valanginian time, the Yucatan block docked in its present position following its counterclockwise rotation, and sea-floor spreading ceased in the central part of the Gulf of Mexico.

The margin of the Gulf of Mexico from the Oxfordian to the Valanginian was passive (fig. 9). Several depositional units of this time interval are interpreted to be significant petroleum source rocks in the Gulf of Mexico, and they might have extended into the northwestern Cuba area. The basinal facies of the Oxfordian Smackover Formation is known to be a prolific source rock in the northern Gulf of Mexico (Sassen and others, 1987). The basinal facies of the Tithonian (Pimienta Formation) is well known as the source for giant oil accumulations in the southern part of the Gulf of Mexico (Magoon and others, 2001), and the coeval Bossier Formation is a potential source rock for gas in the northern Gulf of Mexico Basin (Wagner and others, 2003). The Tithonian organic-rich source rock facies, like the Oxfordian shales, might have extended into the northwestern Cuba area, which would have been a deep-water environment during the Late Jurassic.

Opening of the Proto-Caribbean Ocean Basin

As South America continued to drift away from North America, sea-floor spreading was initiated south of the Yucatan block and the Bahama Platform in about Oxfordian time, forming what has been called the proto-Caribbean ocean basin (fig. 8; Pindell, 1993). As sea-floor spreading continued, the drift of South America from North America led to the development of a passive margin along the south edge of the North American plate. The passive-margin strata associated with the proto-Caribbean plate are now known from the many TSU exposures on Cuba, and these strata are important for the interpretation of petroleum source rocks, reservoirs rocks, and seal rocks in the subsurface of northwestern Cuba.

Passive-margin conditions existed from about Oxfordian through the Late Cretaceous, during which time several potential petroleum source rocks were deposited along the passive margin (fig. 10), including mudstones of the Cenomanian-Turonian, which are known source rocks in the U.S. Gulf Coast.

Movement of the Caribbean Plate

In about Aptian-Albian time, subduction polarity reversed along the western margin of the proto-Caribbean

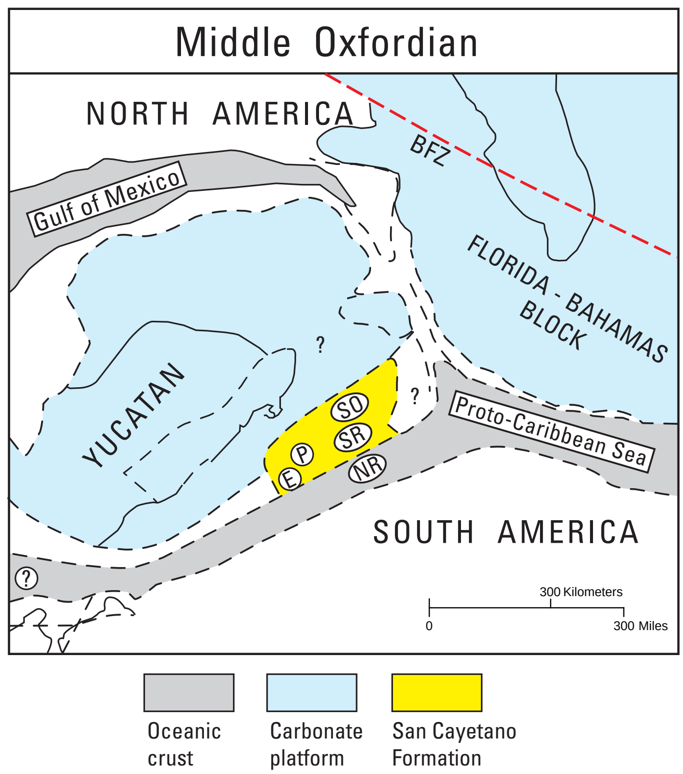

Figure 8. Reconstruction of middle Oxfordian paleogeography showing the partially opened Gulf of Mexico as Yucatan rotated counterclockwise, formation of incipient proto-Caribbean oceanic crust as South America drifted away from North America, and deposition of the San Cayetano Formation and related rocks along the passive margin of Yucatan Platform. Dashed black lines are uncertain geologic boundaries; dashed red line is the Bahama Fracture Zone (modified from Pszczolkowski, 1999). E, Escambray terrane; P, Pinos terrane; SO, Sierra de los Organos terrane; SR, Southern Rosario terrane; NR, Northern Rosario terrane; BFZ, Bahama Fracture Zone.

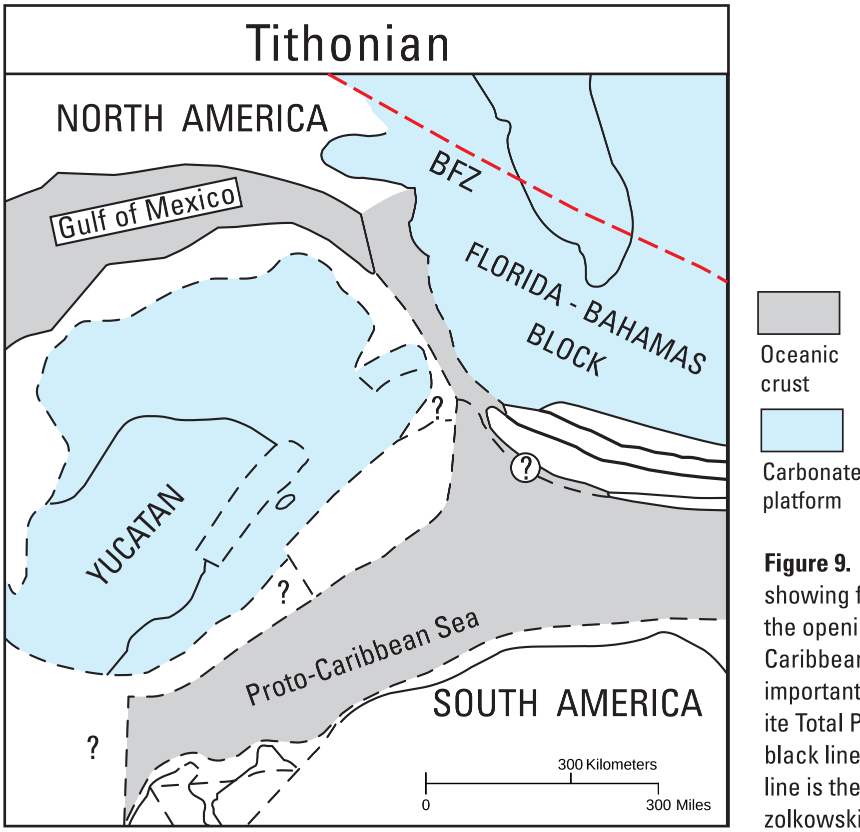

Figure 9. Reconstruction of Tithonian paleogeography showing further counterclockwise rotation of Yucatan and the opening of the Gulf of Mexico and formation of proto-Caribbean oceanic crust. Tithonian source rocks are an important component of the Jurassic-Cretaceous Composite Total Petroleum System in the North Cuba Basin. Dashed black lines are uncertain geologic boundaries; dashed red line is the Bahama Fracture Zone (modified from Pszczolkowski, 1999). BFZ, Bahama Fracture Zone.

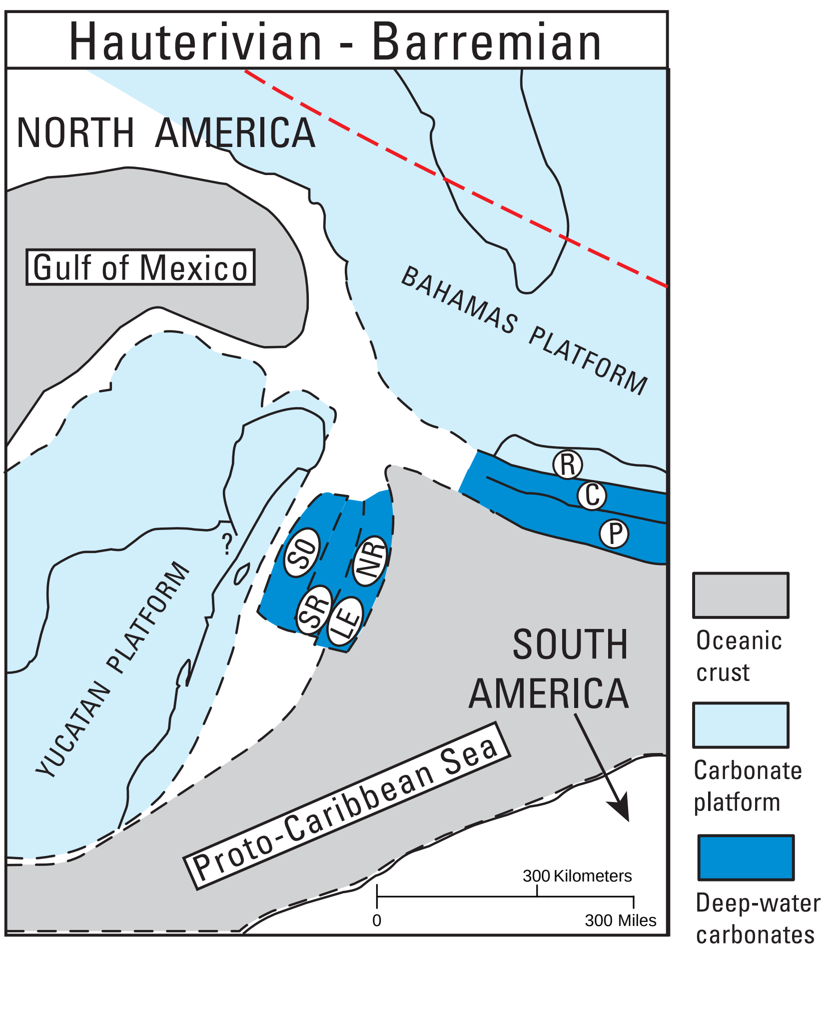

Figure 10. Reconstruction of Hauterivian-Barremian paleogeography showing complete opening of the Gulf of Mexico, further opening of the proto-Caribbean oceanic basin, and development of the passive margins of the Bahama Platform and Yucatan Platform with sediments now named as terranes. Dashed black lines are uncertain geologic boundaries; dashed red line is the Bahama Fracture Zone (modified from Pszczolkowski, 1999). SO, Sierra de los Organos terrane; SR, Southern Rosario terrane; LE, La Esperanza terrane; NR, Northern Rosario terrane; P, Placetas terrane; C, Camajuani terrane; R, Remedios terrane.

plate, allowing Caribbean crust to enter the area between North and South America (Pindell and others, 2005) by subducting proto-Caribbean crust rather than Pacific crust. By Maastrichtian time the westward drift of North America caused the Caribbean crust to collide with the southern part of the Yucatan Platform (fig. 11), forming the Sepur clastic wedge in the resulting foreland basin (Angstadt and others, 1985) (fig. 12). During this time the Guaniguanico terrane was deposited east of the Yucatan passive margin (fig. 12). Many of the formations composing the Guaniguanico terrane are part of the petroleum systems of the North Cuba Basin, as the terrane was disrupted and incorporated into Cuba (fig. 13). By early Paleocene, continued movement of the Caribbean plate caused the leading edge of the plate to break away and move northward (fig. 14), whereas the main Caribbean plate continued to move northeast prior to the formation of the Cayman Trough. The opening of the Yucatan Basin (Case, 1975; Rosencrantz, 1990; Pindell and others, 2005) and subsequent Paleogene spreading of the Yucatan Basin caused Cuba arc-forearc rocks to collide with the passive margin of the Bahama Platform (fig. 15). This explanation is somewhat simplified because the opening of the Yucatan Basin involved movement of a complex assemblage of crustal blocks, faults, and sea-floor spreading (Pindell and others, 2005).

Collision of Cuba Arc-Forearc with the Bahama Platform

The opening of the Yucatan Basin in the Paleogene resulted in the northward translation of Cuba arc and forearc rocks (fig. 15) away from the leading edge of the Caribbean plate. By middle Eocene, the arc-forearc collision with the passive margin of the Bahama Platform culminated, resulting in suturing and welding of the Cuba fold and thrust belt and the Cuban foreland (fig. 16) onto the North American plate. The collision resulted in a series of north-verging thrust sheets and metamorphic complexes that constitute the main geologic elements of the island of Cuba. The thrust sheets for the most part represent strata that formed the southern passive margin of North America admixed with the arc-forearc rocks that arrived from the west and southwest along the leading edge of the Caribbean plate.

Tectonic Summary

A summary of the tectonic development of the northern Caribbean is shown in figure 17. In the Late Cretaceous,

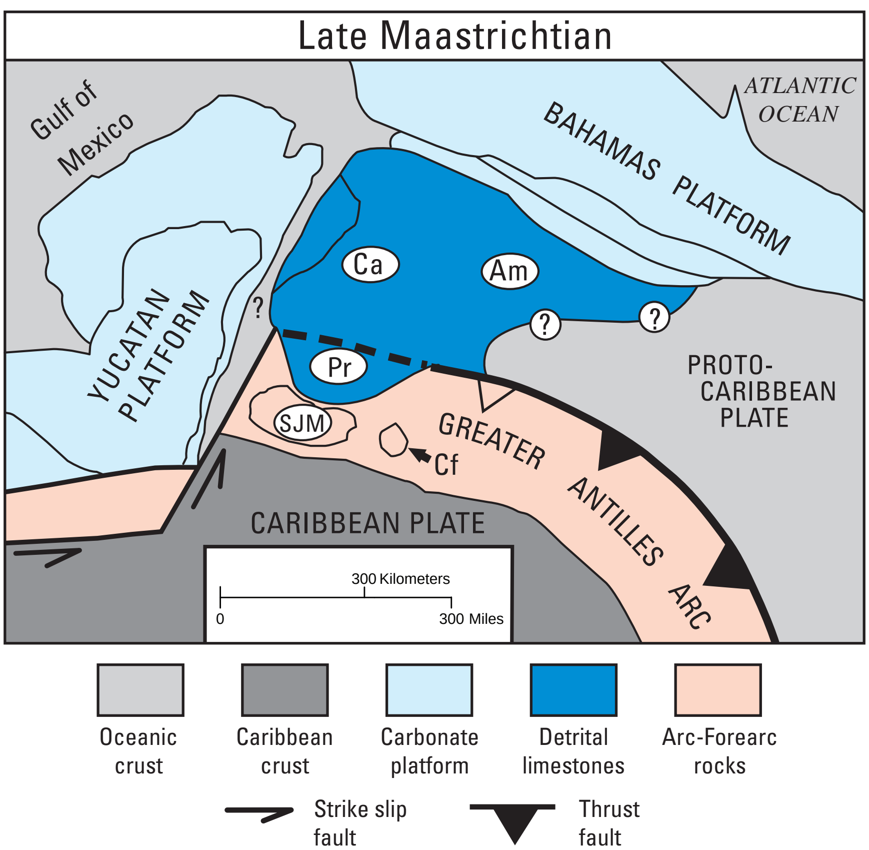

Figure 11. Reconstruction of Late Maastrichtian paleogeography showing migration of the Caribbean plate and arc-forearc from the south, and subduction of proto-Caribbean oceanic crust, with passive margin deposition along the Bahama and Yucatan Platforms (modified from Pszczolkowski, 1999). Ca, Cacarajicara Formation; Am, Amaro Formation; Pr, Penalver Formation; SJM, San Juan and Martinez Basin; Cf, Cienfuegos Basin.

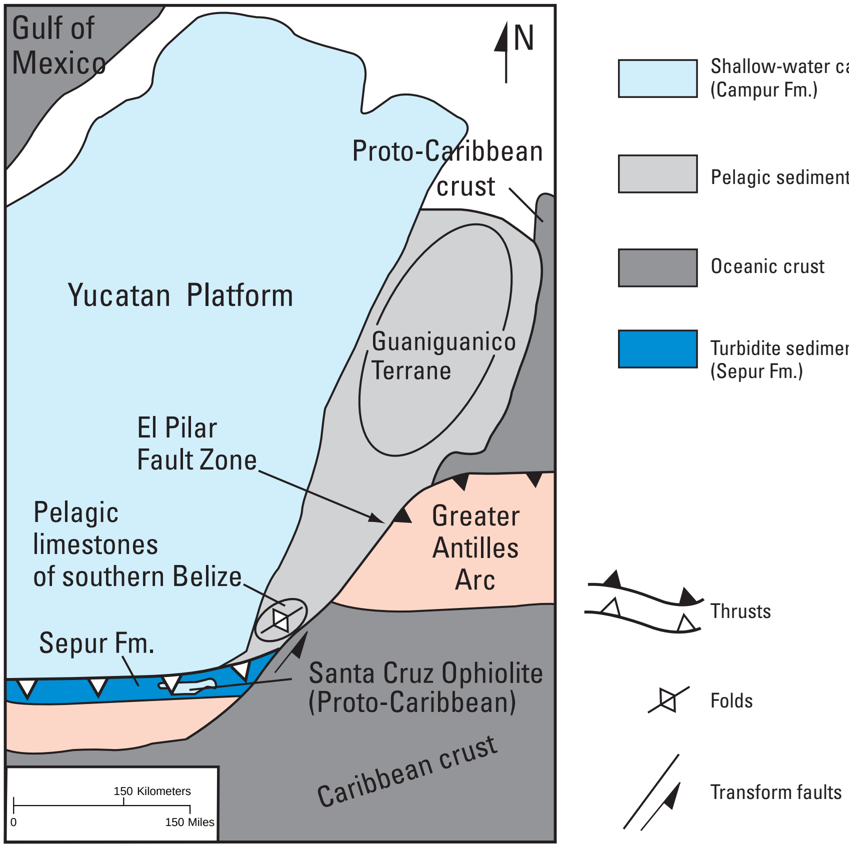

Figure 12. Reconstruction of the Guaniguanico terrane along the Yucatan passive margin and development of the active margin west of the El Pinar fault zone of northwestern Cuba (from Schafhauser and others, 2003).

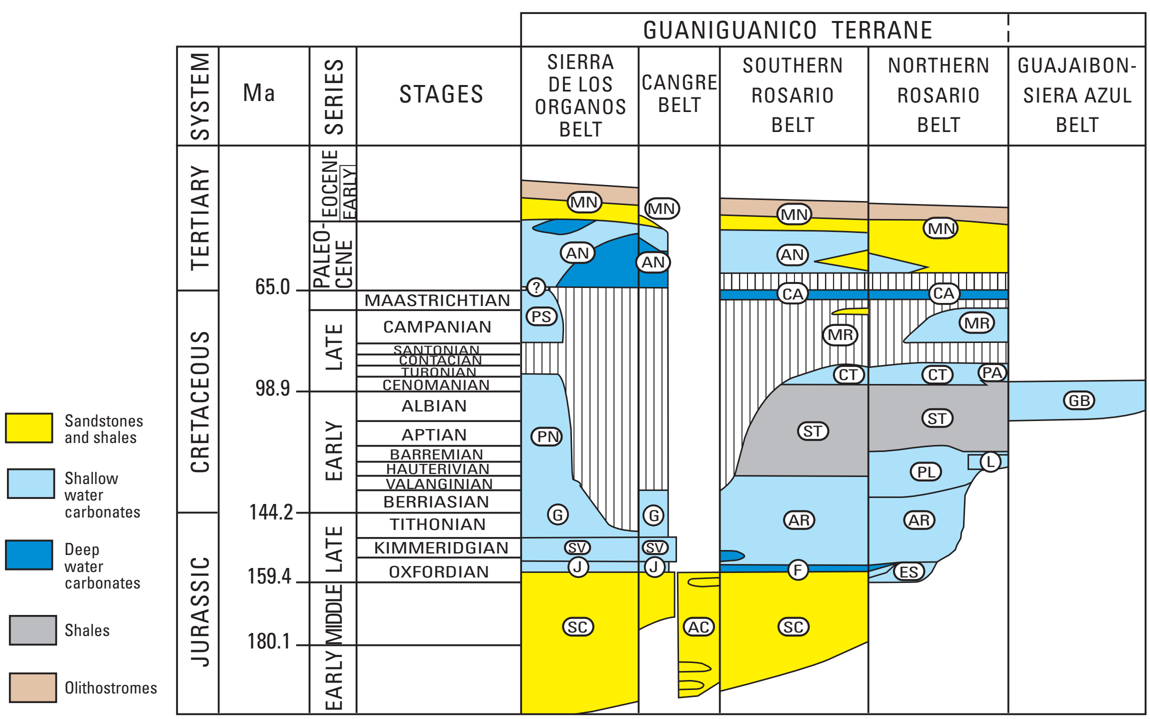

Figure 13. Stratigraphy of the Guaniguanico terrane reflects the presence of Jurassic and Cretaceous source rocks along the east margin of the Yucatan Platform that were incorporated into Cuba as the arc-forearc complex translated northward toward the Bahama Platform in the Paleogene (modified from Pszczolkowski, 1999). SC, San Cayetano Fm.; AC, Arroyo Cangre Fm.; ES, El Sabalo Fm.; J, Jagua Fm.; F, Francisco Fm.; SV, San Vincente Member of Guasasa Fm.; G, Guasasa Fm.; AR, Artemisa Fm.; PL, Polier Fm.; L, Lucas Fm.; ST, Santa Teresa Fm.; GB, Guajaibon Fm.; PN, Pons Fm.; MR, Moreno Fm.; PS, Penas Fm.; CT, Carmita Fm.; PA, Pinalilla Fm.; CA, Cacarajicara Fm.; AN, Ancon Fm.; MN, Manacas Fm..

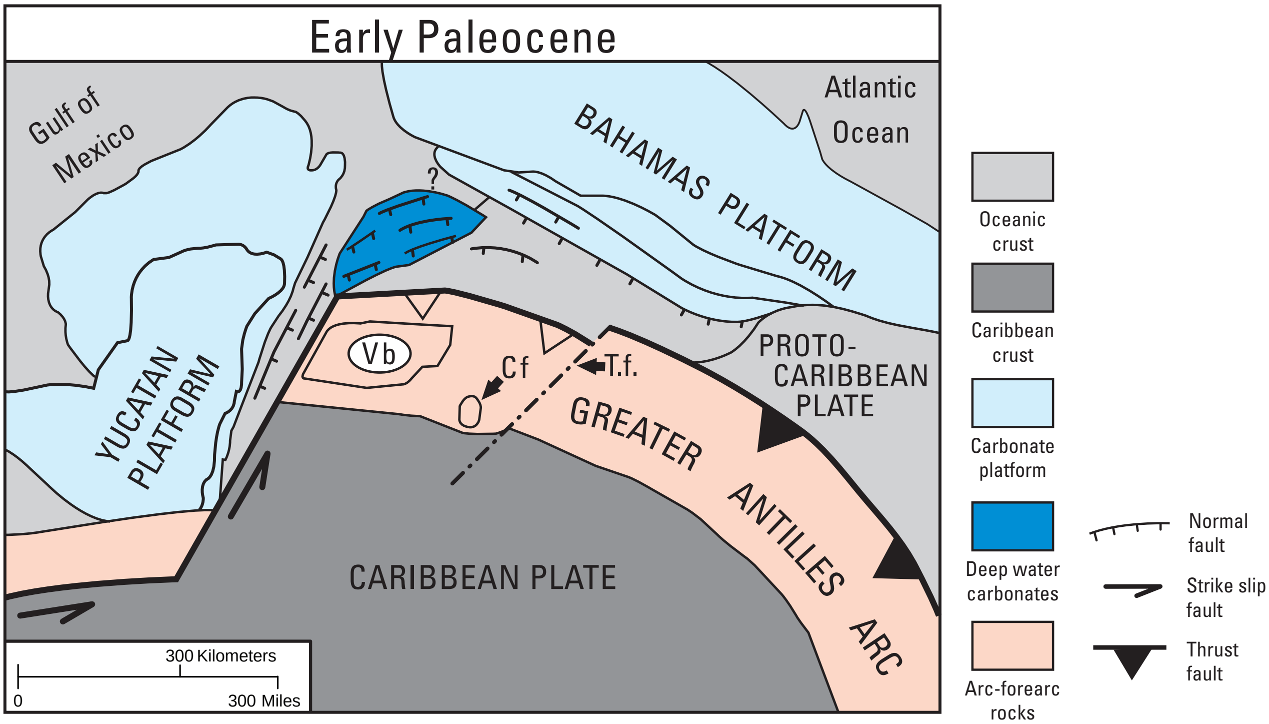

Figure 14. Reconstruction of Early Paleocene paleogeography showing position of the Caribbean plate relative to the proto-Caribbean plate, consumption of oceanic crust by subduction of the proto-Caribbean by the advancing Caribbean plate (modified from Pszczolkowski, 1999). Vb, Vibora Basin; Cf, Cienfuegos Basin; Tf, La Trocha Fault.

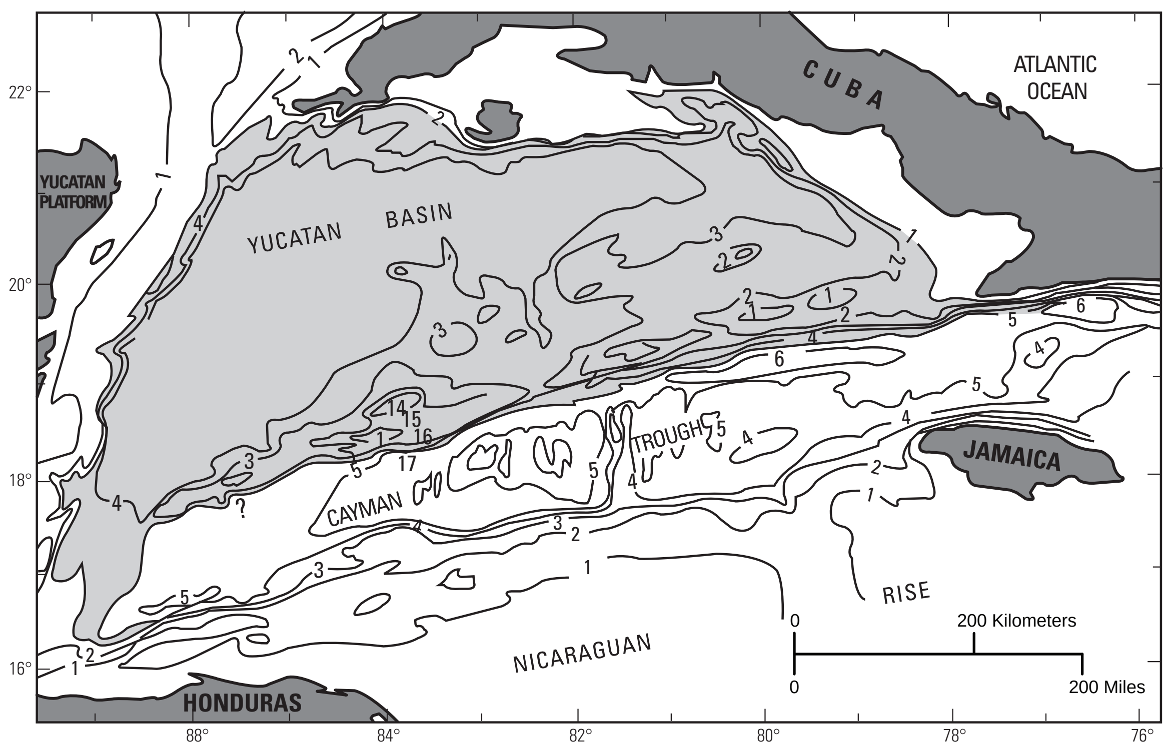

Figure 15. Structure of the Yucatan Basin (light gray area). The Yucatan Basin opened in the Paleogene and caused the Greater Antilles (Cuba) arc-forearc rocks (dark gray area) along the leading edge of the Caribbean plate to move northward and collide with the passive margin of the Bahama Platform (from Holcombe and others, 1990). The Cayman Trough opened subsequent to the Yucatan Basin.

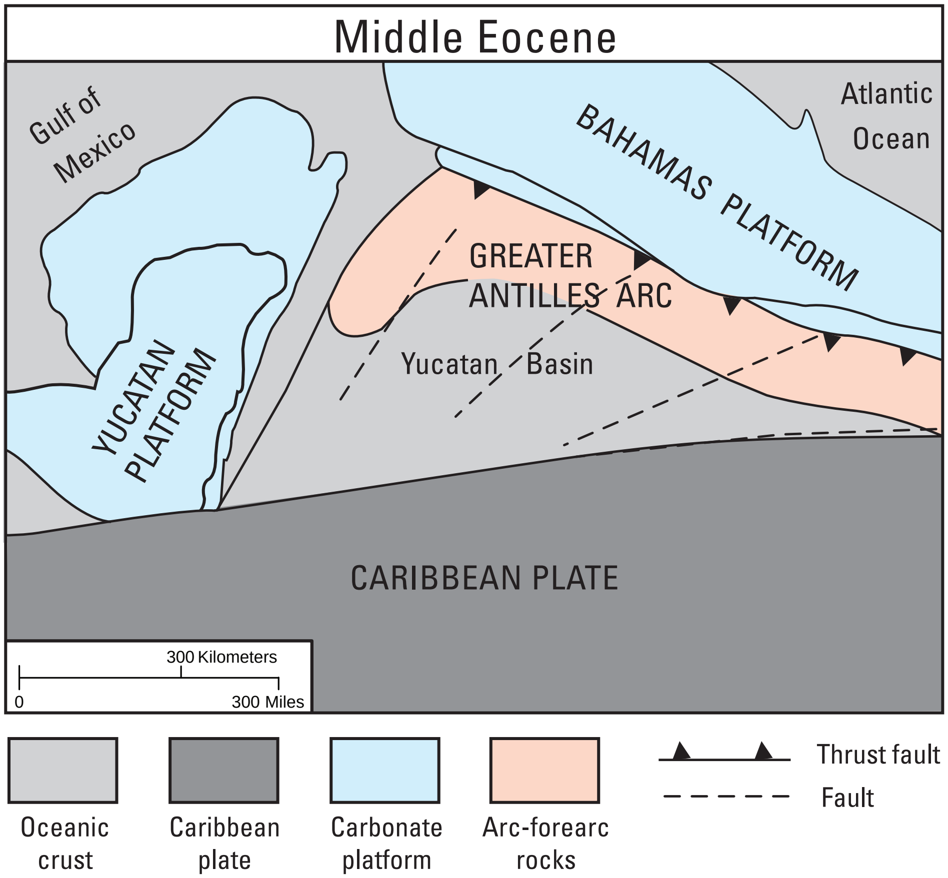

Figure 16. Middle Eocene reconstruction showing the opening of the Yucatan Basin, the collision and suturing of the Greater Antilles arc-forearc with the Bahama platform, leading to the development of the Cuban fold and thrust belt and foreland basin (modified from Pszczolkowski, 1999, and Pindell and others, 2005). Dashed black lines are faults.

the leading edge of the Caribbean plate, possibly having originated in the Pacific realm, arrived at the Yucatan Platform, consuming proto-Caribbean oceanic crust as it migrated to the east and northeast. In the late Paleocene the Yucatan Basin opened by spreading and began to fold and thrust the passive margin sediments and obduct arc-forearc rocks onto the Bahama Platform. This process continued into the Eocene, and by the end of the middle Eocene the arc-forearc was completely sutured onto the North American plate.

The significance of the tectonic history of the northern Caribbean is that organic-rich, passive margin-sediments deposited during Late Jurassic to Paleogene time were progressively buried beneath successive thrust sheets and foreland basin sediments as the Cuban arc-forearc collided with the passive Bahama Platform margin. In addition to the fold and thrust belt, the collision resulted in the formation of a foreland basin whose accommodation space was filled primarily with Paleogene clastic rocks, further adding to the overburden and thereby might have assisted in the thermal maturation of the Mesozoic organic-rich rocks. Thus, the tectonic history is a direct cause for the development of petroleum systems in the North Cuba Basin.

Looking specifically at the area that is now the North Cuba Basin, the tectonic history had a direct influence on the elements of the petroleum system. In figure 18*A*, the area was dominated by Mesozoic rift basins. These, in turn, were overlain by Upper Jurassic and Cretaceous shallow and deep-water carbonate sediments, several of which are organic-rich (fig. 18*B*). In the Paleogene, the initiation of the fold and thrust belt caused some of these source rocks to be buried sufficiently to reach the generative thermal windows for oil (fig. 18*C*). Further thrusting resulted in the formation of the Cuban foreland, and some of the extensional structures associated with rifting were inverted (fig. 18*D*). By the middle Eocene suturing was complete, and the foreland continued to accumulate clastic sediments, further burying potential source rocks into the generative windows for oil and gas (fig. 18*E*). A summary of the main tectonic events and the relation to petroleum system elements of the North Cuba Basin is presented in figure 19.

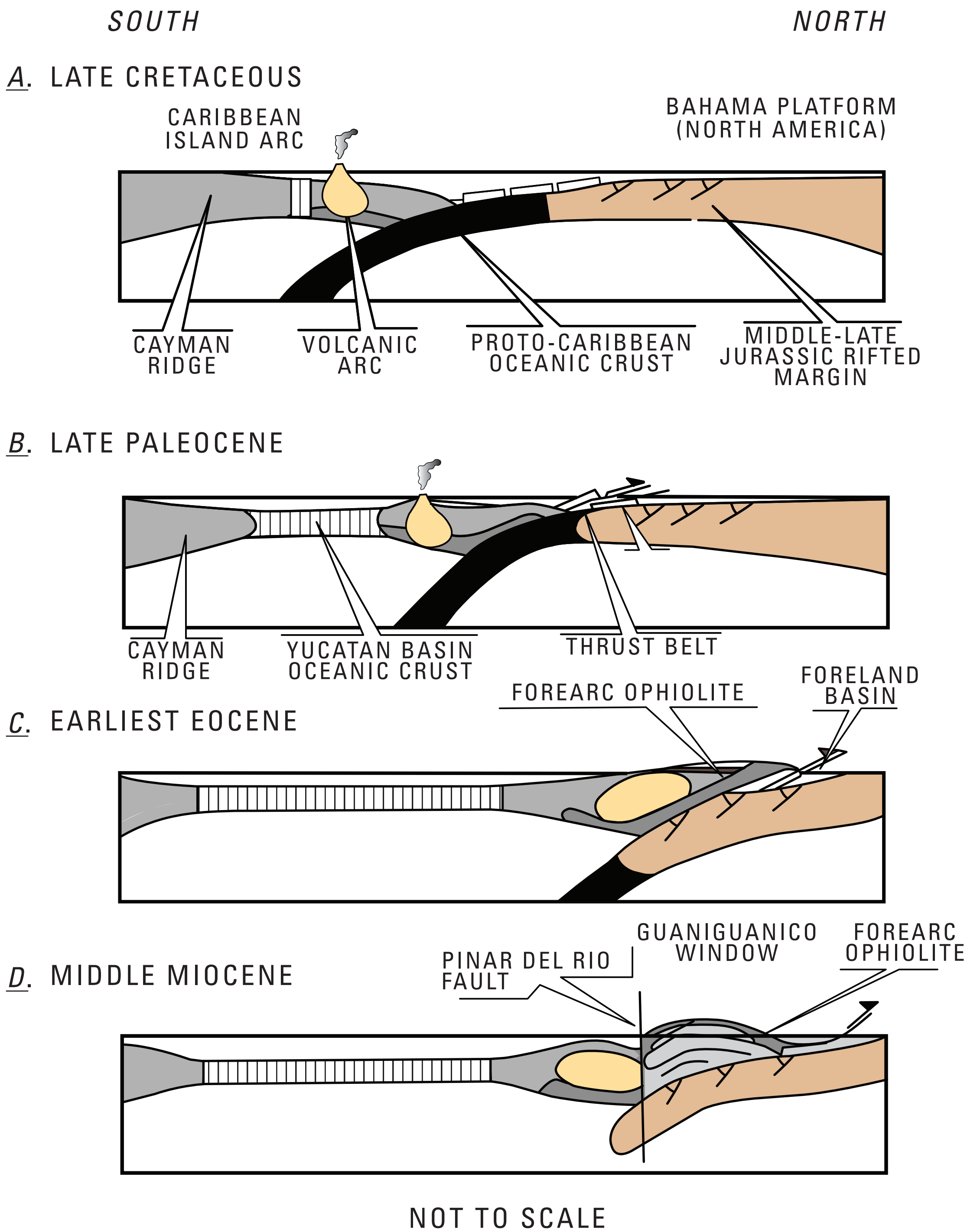

Figure 17. Tectonic model for the development of the Cuban fold and thrust belt and foreland (from Gordon and others, 1997).

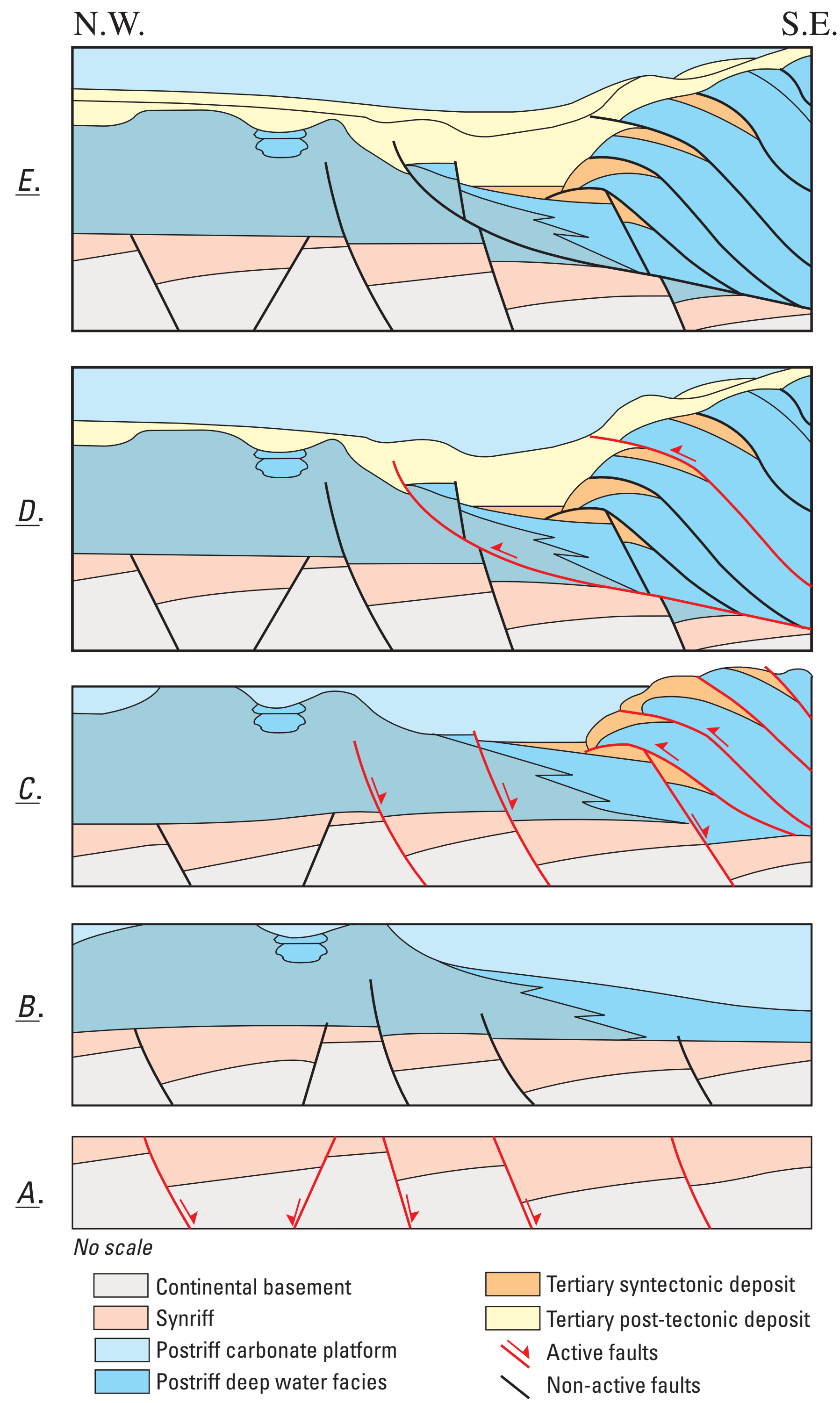

Figure 18. Sequential development of the northwest Cuban fold and thrust belt and the foreland associated with the fold belt. *A*, Proto-Caribbean synrift (Early to Middle Jurassic) development of rift basins; *B*, post-rift subsidence; *C*, end of Greater Antilles orogeny in early Eocene; *D*, infilling of basin, which began as foreland in previous phase; *E*, passive subsidence caused by sediment influx from Cuba (after Moretti and others, 2003b).

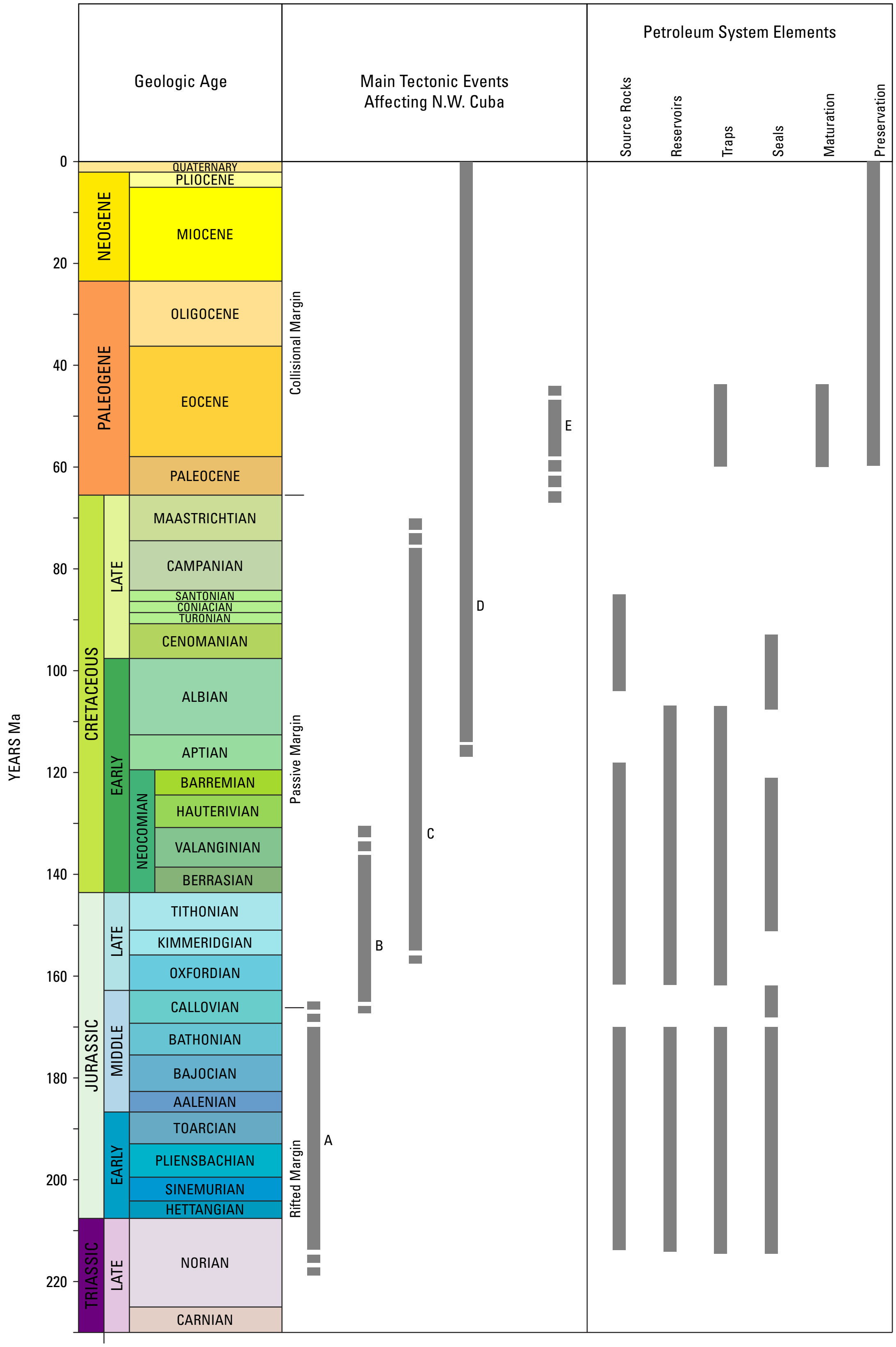

Figure 19. Summary of tectonic events affecting the northwestern Cuba area and the main elements of the Jurassic-Cretaceous Composite Total Petroleum System. Letters A-E refer to time intervals represented by diagrams shown in figure 18. Dashes reflect uncertainty of timing of geologic events.

Jurassic-Cretaceous Composite Total Petroleum System

A TPS is an integration of the tectonic, sedimentary, and thermal history of an area (Pindell, 1991) and is defined to encompass all fluids that have been generated from genetically related pods of thermally mature petroleum source rocks (Magoon and Dow, 1994). In the North Cuba Basin, three major types of oils are present, which reflects the presence of potential source rocks. However, it is not possible on the basis of currently (2008) available geochemical information to isolate and define separate petroleum systems. Accordingly, a single petroleum system—The Jurassic-Cretaceous Composite Total Petroleum System—was defined for the North Cuba Basin (fig. 20).

Source Rocks

As indicated above, geochemical analyses and interpretations of samples of potential petroleum source rocks, oils, and gases have quantitatively defined several source rocks and potential petroleum systems of the North Cuba area (Maksimov and others, 1986; Lopez-Quintero and others, 1994; Lopez-Rivera and others, 2003a, b; Moretti and others, 2003a,b; Magnier and others, 2004). These are: (1) Lower to Middle Jurassic rift-related mudstones; (2) Upper Jurassic and Lower Cretaceous deep-water organic-rich carbonate mudstones; (3) Upper Cretaceous deep-water carbonate mudstones; and possibly (4) Paleogene mudstones. Of these, the Upper Jurassic and Lower Cretaceous deep-water carbonate mudstones are considered to be volumetrically the most significant petroleum source rocks in the basin (Moretti and others, 2003a,b). Paleogene source rocks and fluids also have been reported, but these fluids are not considered to be volumetrically significant because of the low level of thermal maturation of these sediments (Magnier and others, 2004) relative to the generative windows in the foreland basin. Each of these potential source rocks are described briefly in the following paragraphs.

Lower to Middle Jurassic Rift-Related Mudstones

Field investigations in western Cuba have revealed the presence of Lower to Middle Jurassic rift-related facies composing the San Cayetano Formation (fig. 7; Haczewski, 1976). The formation is exposed in western Cuba, having been placed in that position by the compressional tectonics between the Cuban allochthonous assemblage and the passive margin

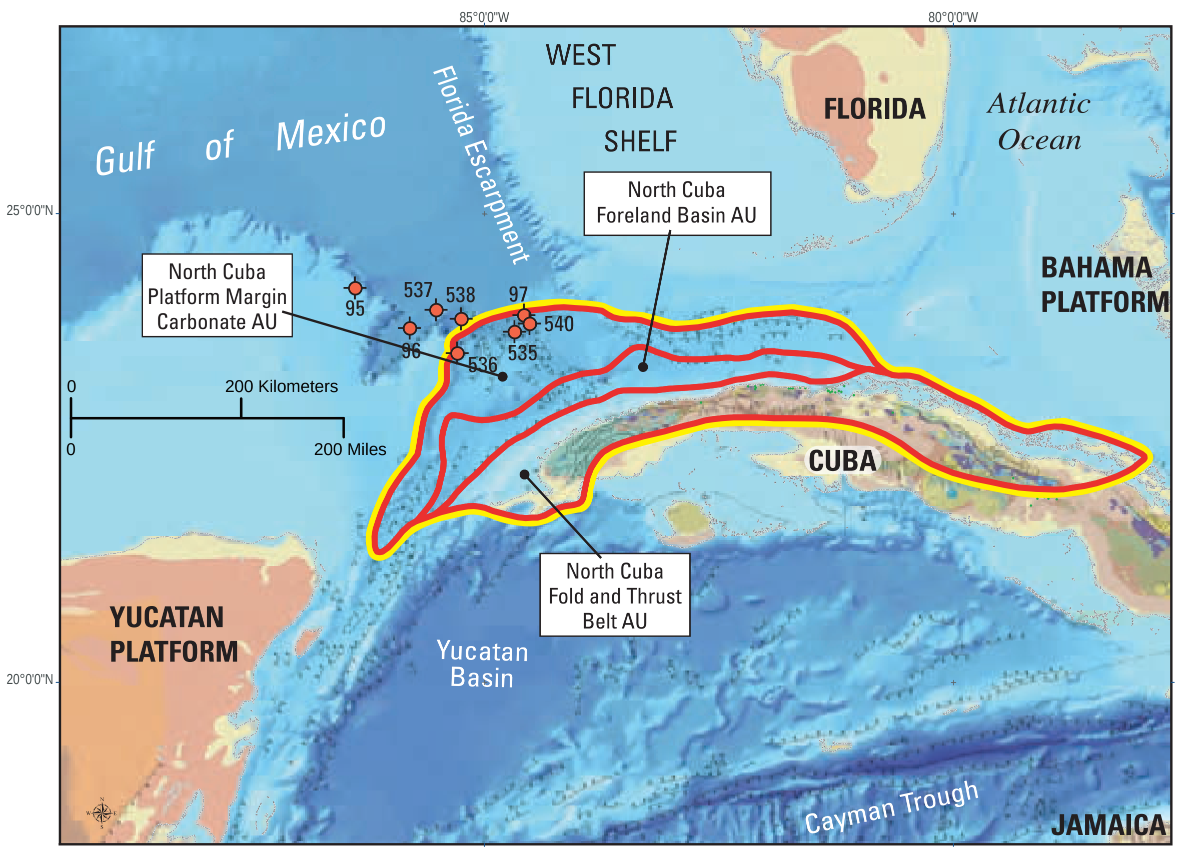

Figure 20. Boundary of the Jurassic-Cretaceous Composite Total Petroleum System (yellow line) and three assessment units (AU) defined in this study (red lines). Red symbols refer to numbered Deep Sea Drilling Project wells.

of North America during the Paleogene. The San Cayetano Formation might have been part of the passive margin of the Yucatan Platform during rifting (fig. 8), and the terrane subsequently was detached, moved northeastward, and welded onto the Cuban assemblage during the opening of the Yucatan Basin in the Paleogene.

The San Cayetano Formation formed during the rifting of South America from North America. From Late Triassic through early Late Jurassic time, rifting resulted in attenuated continental crust and the formation of grabens, half grabens, and other rift related structures. The structures have been imaged seismically (Lopez-Rivera and others, 2003b) and are similar to coeval structures reported from the U.S. Gulf Coast (Salvador, 1987; 1991). The rift facies have been described from several thrust-bounded rock packages in western Cuba where the facies of the San Cayetano Formation and the Francisco Formation have been examined in detail.

The involvement of the San Cayetano Formation in the tectonic slices makes a determination of its original thickness difficult, but estimates of thickness range to as much as 5,000 m. Facies descriptions of the formation are typical for rift basins, with rapid facies changes and difficult correlations. Haczewski (1976) defined several facies of the San Cayetano, including fluvial, possibly nearshore marine and estuarine sandstones and mudstones, lagoonal mudstones, and a series of slope-basin turbidite facies including sandstones and mudstones; all sandstones are potential reservoirs in the subsurface.

Significant to the issue of petroleum source rocks are the lagoonal facies and the deep-water black shales that were examined in outcrop. Analyses of black shales of the San Cayetano and Francisco formations from western Cuba by Moretti and others (2003b) demonstrated that the shales are organic-rich and are thermally overmature with respect to oil generation. Measurements were made of total organic carbon (TOC), a standard measure of the weight percent of organic matter in a rock that represents only that organic carbon remaining after maturation and possible expulsion of petroleum. Remnant TOC values for the black shales range from 0.7 to 3.3 weight percent. Average initial TOC is estimated at approximately 3 weight percent, but initial TOC could have been higher. The black shales were interpreted to contain oil-prone marine Type IIS organic matter by Moretti and others (2003b). These data indicate that similar rift-related black shales in the subsurface, which are known to exist throughout most of the southeastern Gulf of Mexico, might be petroleum source rocks (fig. 21).

At present (2008), no petroleum produced from oil fields in Cuba has been genetically tied to rift-related black shales. Theoretically, these fluids would be geochemically distinct from fluids originating in the deep-water carbonate facies of the Upper Jurassic and Cretaceous strata. Without specific data, a separate rift-basin petroleum system cannot be defined in the North Cuba Basin, but this may be designated as a distinct petroleum system in the future. The rift-related black-shale facies might be present over a large part of the assessment area (fig. 21), and given that the shales may be thermally mature to overmature, petroleum might have been generated from these shales, migrated, and formed accumulations related to the rift basins. This concept is considered a possibility in several exploration play definitions for the North Cuba Basin (Moretti and others, 2003b).

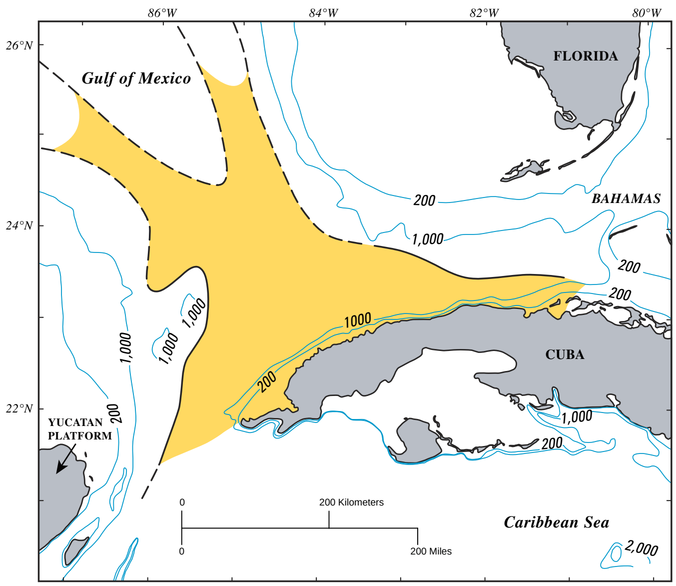

Figure 21. Present-day distribution of postulated synrift Jurassic source rocks; original extent most likely was further south prior to thrust shortening. Dashed lines reflect uncertainty of source-rock extent (from Moretti and others, 2003b).

Similar rift basins are present in the U.S. Gulf Coast where the rift facies are collectively referred to as the Eagle Mills Formation, and in east-central Mexico where the facies are called the Huayacocotla and Hulzachal formations (Salvador, 1991). Although the Eagle Mills Formation is informally referred to as a “red-bed” facies based on limited drilling, Salvador (1991) states that organic-rich mudstones and local coal beds are typical of these facies, indicating that source rocks might be present in these rifts. However, the presence of source facies would be strongly dependent upon paleoclimate.

In summary, data from northwestern Cuba indicate that some rift-related black shale might have contained sufficient organic matter to have served as petroleum source rocks, but much uncertainty remains. Seismic data interpretations have shown the presence of numerous rifts in the assessment area, indicating that these rifts might have petroleum source rocks. Modeling shows that the shales in the rift grabens in the North Cuba Basin might have generated petroleum in the Jurassic, and that these fluids might have been sealed within reservoirs of the rift basins or might have migrated out and up into reservoirs of the post-rift sequences (Moretti and others, 2003b; Vassalli and others, 2003). Another issue is that the fluids originating from these shales might be gas at present rather than oil because the shales are thermally overmature for oil.

Upper Jurassic-Lower Cretaceous Deep-Marine Carbonates

Deep-marine, fine-grained, organic-bearing carbonate mudstones of the Upper Jurassic and Lower Cretaceous interval are considered to be the most significant petroleum source rocks in the North Cuba Basin (figs. 22, 23). These source rocks crop out in western Cuba, and source-rock data from outcrops were summarized by Moretti and others (2003b). Upper Jurassic rocks, specifically Upper Oxfordian and Tithonian deep-water carbonates, were deposited basinward of shallow-water carbonate platforms that rimmed the southeastern Gulf of Mexico in the Late Jurassic (Salvador, 1991; Pindell and Kennan, 2001). The basinal carbonates are fine grained, with alternations of dark organic-bearing lamina with grayer, less organic-bearing carbonate lamina; TOC values average about 3 weight percent, with some measurements as high as about 7 weight percent (table 2).

Upper Oxfordian deep-marine carbonates are the primary source rocks in the northern U.S. Gulf Coast for petroleum in the Jurassic Smackover Formation reservoirs (Sassen and others, 1987). Tithonian deep-marine carbonates are the primary petroleum source rocks in the Mexican southern Gulf of Mexico (Magoon and others, 2001), and these rocks are the source for petroleum in many of the major Mexican Gulf Coast oil fields. Tithonian shales might contain significant gas resources in the U.S. Gulf Coast as well, mainly from the Bossier Formation (Wagner and others, 2003).

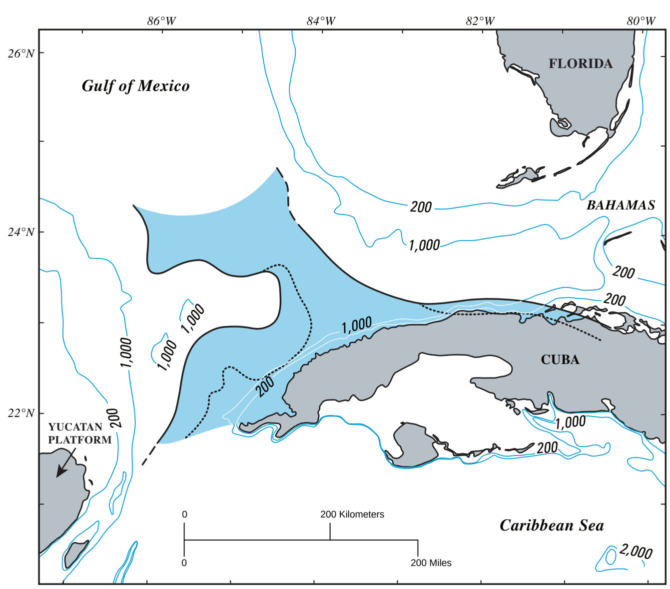

Figure 22. Present-day distribution of Upper Jurassic deep-water carbonate source rocks (shaded blue); original extent most likely was further south overlying proto-Caribbean crust prior to thrust shortening in the Paleogene. Dashed lines reflect uncertainty of source-rock extent (from Moretti and others, 2003b). Contours are water depths, in meters.

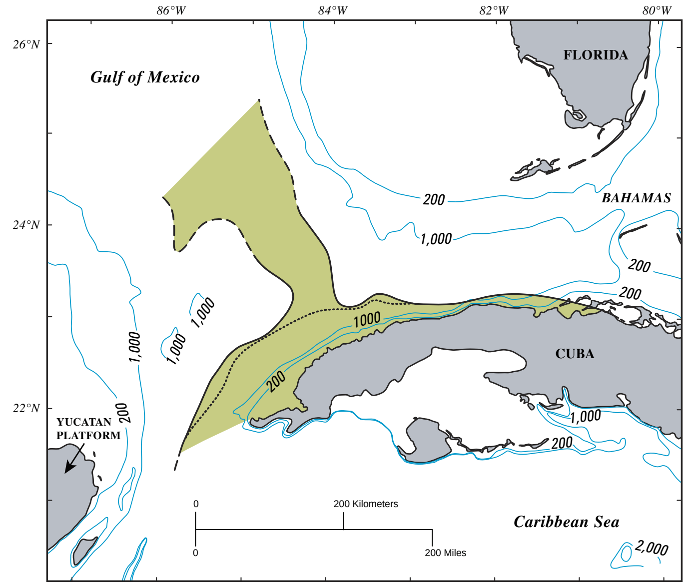

Figure 23. Present-day distribution of Lower Cretaceous deep-water carbonate source rocks (shaded green); original extent most likely was further south prior to thrust shortening in the Paleogene. Dashed lines reflect uncertainty of source-rock extent (from Moretti and others, 2003b). Contours are water depth, in meters.

Upper Cretaceous Deep-Marine Carbonates and Mudstones

Deep-marine carbonate mudstones from the Cenomanian-Turonian interval are known source rocks in the U.S. Gulf Coast region. These rocks might be present in the passive margin section of Northwest Cuba that was overridden by the thrust sheets in the Paleogene (fig. 24). Moretti and others (2003b) have shown that samples of Cenomanian mudstones, in addition to Albian and Aptian samples, had TOC values above 1 weight percent. They suggested that TOC values could be as high as 3 weight percent, with hydrogen index (HI) values greater than 600, both parameters indicating an excellent potential source for oil. The thickness of the Cenomanian interval in northwest Cuba is unknown, and it is possible that some of the Cenomanian section was eroded. The Cenomanian source rocks, which are included with rocks of Aptian and Albian age, were analyzed as having Type II and Type IIS organic matter (Moretti and others, 2003b), indicating a marine oil-prone source rock. They also interpreted the source rocks as having a hypersaline-anoxic origin (table 2), similar to the results reported by Navarrete-Reyes and others (1994). Thermal maturation of Aptian through Cenomanian rocks was modeled by Moretti and others (2003b), and the results indicate that these rocks are thermally immature in the foreland basin and carbonate platform areas, but are thermally mature in the fold and thrust belt.

Table 2. Oil fields of the onshore North Cuba Basin; North Cuba Fold and Thrust Belt Assessment Unit.

Tectonic Setting	Source Rock Group	Total Organic Carbon Remnant (Weight %)	Total Organic Carbon Original (Weight %)	Organic Matter Type	General Level of Present Thermal Maturity: Thrust Belt	Foreland	Deep Marine	General Depositional Environment	Specific Depositional Conditions
Synrift	Lower-Middle Jurassic	0.7 - 1.5	~ 3	Type II	B - M	O - M	M(?)	Siliclastic Shales	Deep Marine (?)
Post-Rift Passive Margin	Upper Jurassic - Barremian	up to 7.6	~ 3	Type II, IIs	M	M	I	Deep Marine Carbonates	Hypersaline/Anoxic
Post-Rift Passive Margin	Aptian - Cenomanian	up to 3.1	~ 3	Type II, IIs	M	I	I	Deep Marine Carbonates	Hypersaline/Anoxic
Foreland Basin	Paleocene - Eocene	?	?	?	I	I(?)	I	Siliclastic Shales	?

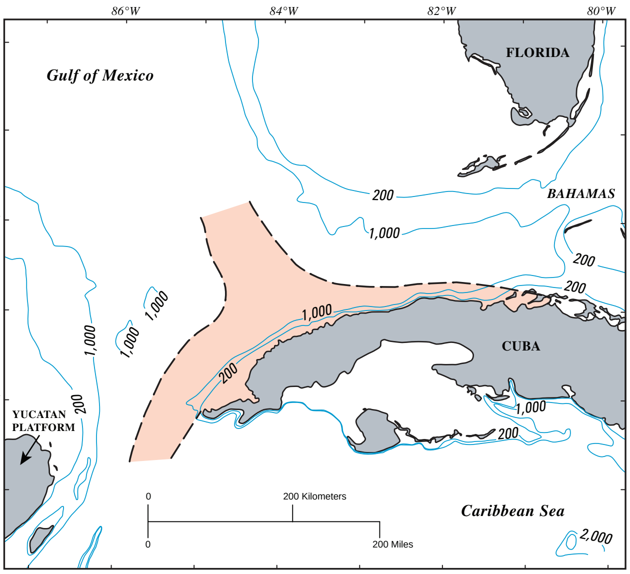

Figure 24. Postulated present-day distribution of Cenomanian-Turonian source rocks (shaded orange); original extent most likely was further south prior to thrust shortening in the Paleogene. Dashed lines reflect uncertainty of source-rock extent. Contours are water depth, in meters.

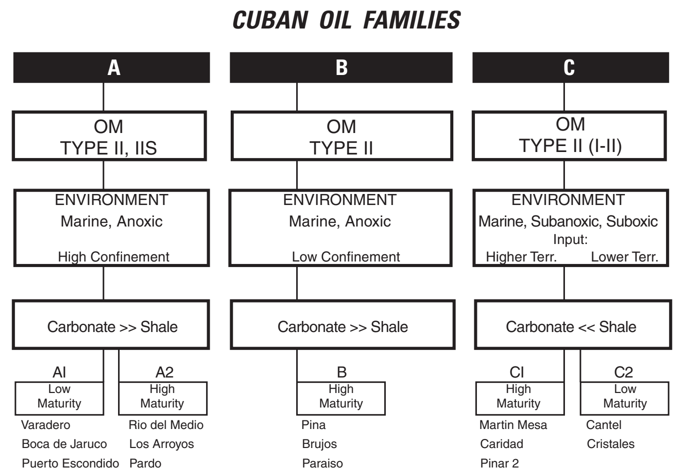

Figure 25. A geochemical classification of Cuban oil families (from Lopez-Rivera and others, 2003a). Labels in top tier of open boxes refer to types of organic matter; labels above bottom tier of boxes refer to oil subfamilies. Examples of oil fields in each oil family are given at bottom of figure.

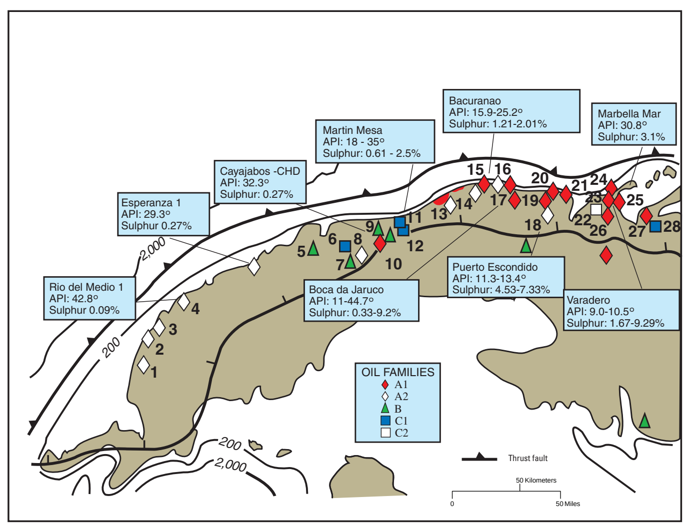

Figure 26. Quality of oils in northwestern Cuba within the classification of the three main oil families characterized in figure 24 from Lopez-Rivera and others (2003a).

Paleogene Mudstones

Mudstones of Paleogene age have high TOC values in some samples (Moretti and others, 2003b). Generally, sediments of this age are thermally immature and probably have not contributed significantly to the petroleum system in the North Cuba Basin (table 2).

Summary of Cuban Oil Geochemistry

Detailed geochemical studies have documented at least three major families of oils in the North Cuba Basin having originated from several potential source rocks (fig. 25). Oil families have been differentiated on the basis of organic matter type, depositional environment, lithology of source rock, and thermal maturation of the petroleum. Oil quality, generally shown as a function of API gravity and sulfur content, shows a wide range of values for north Cuba oils (fig. 26) and a complex geographic distribution of the three oil types. The oil-quality data indicate that, contrary to the view that most Cuban oils are heavy (API gravity <20 degrees), there is a wide range of API gravities (9-43 degrees), and a wide range of sulfur contents (fig. 26) most likely because of biodegradation (Campos-Jorge and others, 1994).

Data on sulfur content and API gravity indicate that some of the Cuban oils have been biodegraded, resulting in the lower API gravities and higher sulfur contents (Campos-Jorge and others, 1994), but this is not true for all Cuba oils (fig. 27). As for hydrocarbon potential, many samples from northern Cuba plot with TOC values greater than 1 weight percent, and therefore could be petroleum source rocks (fig. 28). Geochemical data also indicate that many of the Cuban oils originated from source rocks that were deposited as carbonate sediments under anoxic and hypersaline depositional environments, possibly in deep water. A few oils indicate a siliciclastic Paleogene source (fig. 29).

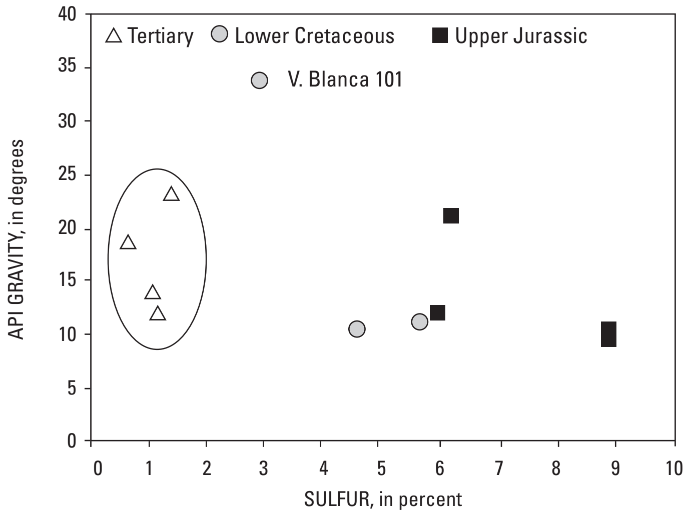

Figure 27. Plot of percent sulfur and API gravity for some Cuban oils in Upper Jurassic, Lower Cretaceous, and Paleogene rocks (from Magnier and others, 2004).

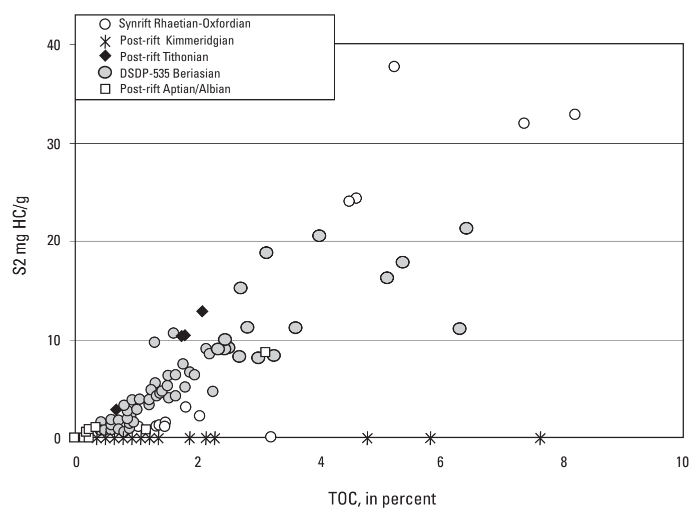

Figure 28. Plot of Rock-Eval data from Cuba onshore source rock samples and samples from DSDP well 535 showing distribution of total organic carbon (TOC) values (from Magnier and others, 2004). S2 mg HC/g, value of milligrams of hydrocarbon/gram of source rock from the Rock-Eval S2 peak..

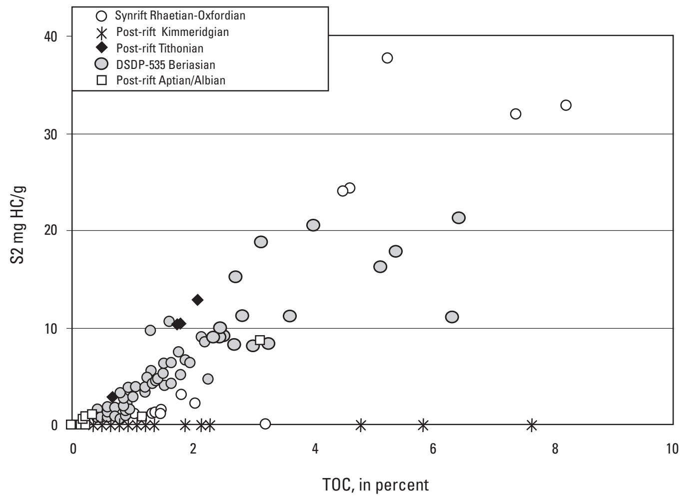

Figure 29. Map showing boundaries of the Jurassic-Cretaceous Composite Total Petroleum System (yellow line) and the three assessment units defined in this study.

Geochemical data indicate that several oils from different source rocks are present in the North Cuba Basin, and that there are several oil families based on geochemical data (table 3). However, the oils are located in complex structures within the fold and thrust belt and are distributed somewhat randomly. In addition, the oils are difficult to differentiate and map into distinct families on a regional basis. For this reason, a composite TPS was defined in the North Cuba Basin.

Petroleum Generation

Moretti and others (2003b) discussed the results of thermal modeling aimed at determining the timing of petroleum generation in several source-rock intervals in the North Cuba Basin. For the synrift source rocks, modeling results indicate that the synrift source rocks are overmature with respect to oil generation within the thrust belt and foreland basin areas. Within the deep offshore area, synrift source rocks are interpreted to be just within the oil generation window. For the Upper Jurassic and Lower Cretaceous fine-grained carbonate source rocks, modeling indicates probable thermal maturity within the thrust belt and possibly also in the deeper parts of the foreland; however, in the majority of the foreland and platform areas, modeling indicates the rocks are thermally immature for oil generation. This conclusion is corroborated by the findings from the Deep Sea Drilling Project (DSDP) Site 535 well (discussed below). Modeling also indicates that gas generation may have occurred within the thrust belt and the deeper parts of the foreland (Moretti and others, 2003b).

Table 3. Geochemical parameters of some onshore oils from the North Cuba Basin (after Moretti and others, 2003a, b). ppm, parts per million.

[ppm, parts per million; - -, no data.]

Oil Family	Well Sample	Sample Depth (meters)		Reservoir Age	Formation	API°	SULFUR (percent)	Nickel (ppm)	Vanadium (ppm)
A	- -	- -	- -	- -	- -	- -	- -	- -	- -
B	Yumuri 37	1280	1350	Upper Jurassic	Cifuentes	6.3	5.96	70	111
	Yumuri X	2321	3600	Upper Jurassic	Cifuentes	- -	7.64	54	102
	Via Blanca 103	1989	2054	Upper Jurassic	Cifuentes	21.1	6.20	30	50
	Boca Jaruco 359	1826	1857	Upper Jurassic	Cifuentes	- -	6.76	28	47
	Varadero 103	1690	1720	Upper Jurassic	Cifuentes	9.6	8.9	68	109
	Varadero 306	1613	1645	Lower Cretaceous	Cifuentes	10.4	8.9	66	105
	Yumuri 31	1487	1467(?)	Lower Cretaceous	Ronda	10.4	4.6	- -	- -
	Via Blanca 101	1380	1410	Lower Cretaceous	Carmita	33.7	2.9	9	14
	Boca Jaruco 370	1306	1356	Lower Cretaceous	Carmita	- -	3.53	23	23
	Marabella Mar 1	2550	2565	Lower Cretaceous	Paraiso	11.0	5.69	45	76
	Cantel 33	1140	1172	Upper Cretaceous	Carmita	- -	- -	- -	- -
C	Marabella Mar 2	1898	1912	Paleocene	Vega	26.6	- -	- -	- -
	Cantel 30	477	683	Paleocene	Serpentinite	12.0	1.17	- -	- -
	Cantel 229	424	488	Paleocene	Serpentinite	14.1	- -	41	41
	Martin Mesa 1	824	807(?)	Lower Eocene	Manacas	23.2	1.38	12	12
	Martin Mesa 24	733	773	Lower Eocene	Manacas	18.6	0.69	5	5

Petroleum Migration

The most significant geologic uncertainty in the Jurassic-Cretaceous Composite TPS is the efficacy of lateral petroleum migration. Clearly, petroleum source rocks are present, and some have reached generative thermal maturity. However, the source rocks had to be thermally mature at depth to have produced the oil in Cuba, at DSDP Site 535, and in wells along the south margin of the Bahama platform. The degree to which petroleum migration has occurred beyond the fold and thrust belt to permit trapping and pooling of significant volumes of petroleum is highly uncertain. Petroleum was generated as thrust loading and burial of source rocks in the Paleogene resulted in thermal maturity. Fluids generated within the thrust belt migrated vertically to the 20-plus known fields, and fluids might have migrated laterally into reservoirs within the foreland basin and to the carbonate platform margin. That some lateral migration has occurred is shown by the oil in cores at DSDP Site 535 well. Lateral migration might not have been possible for petroleum generated within the synrift strata, because the presence of evaporites such as halite and anhydrite within the Middle Jurassic section and the fine-grained carbonates that were deposited during the Berriasian flooding event would have served as seals to limit the lateral movement of synrift petroleum (Magnier and others, 2004). Lateral migration of petroleum from Upper Jurassic and Lower Cretaceous source rocks would not have been as constrained as that generated from source rocks within the synrift section. Structural barriers such as faults also might have limited lateral migration. Parnell and others (2003) interpreted some petrologic information from oil-bearing samples from the fold and thrust belt to indicate that there might have been multiple episodes of oil migration related to the multiple thrust events.

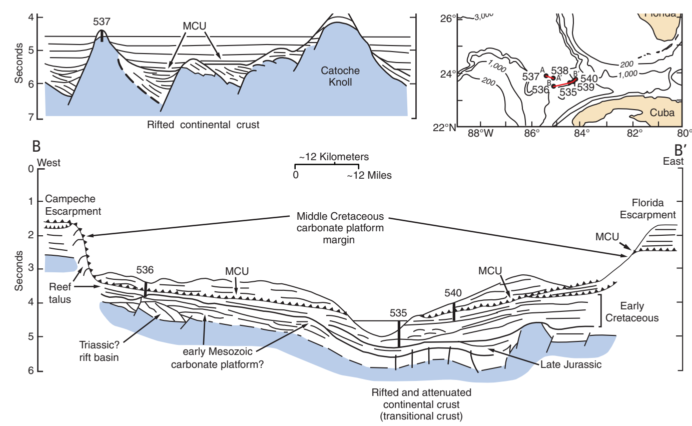

Figure 30. Location of wells drilled on Leg 77 of the Deep Sea Drilling Project. Site 535 well is shown on an interpreted seismic section (B-B′). The Jurassic and Cretaceous sedimentary section at this location is thermally immature for petroleum generation, so oil reported from core in this well must have migrated to this locality. Gray shade is basement rock (from Buffler and others, 1984). MCU, Middle Cretaceous unconformity.

Significance of DSDP Site 535 Well, Southeastern Gulf of Mexico

In 1981 several wells were drilled in or near the Jurassic-Cretaceous Composite TPS in the North Cuba Basin during Leg 77 of DSDP (fig. 2). The main objective was to sample shallow Cretaceous carbonate rocks thought to exist in the area. Six wells were drilled, and cores from one of the wells, Site 535, contained what were interpreted as oil stains and asphalt-filled fractures (Herbin and others, 1984; Katz, 1984; Palacas and others, 1984a; Patton and others, 1984). These shows of petroleum bear directly on the definition and mapping of the composite petroleum system in the northwestern part of Cuba.

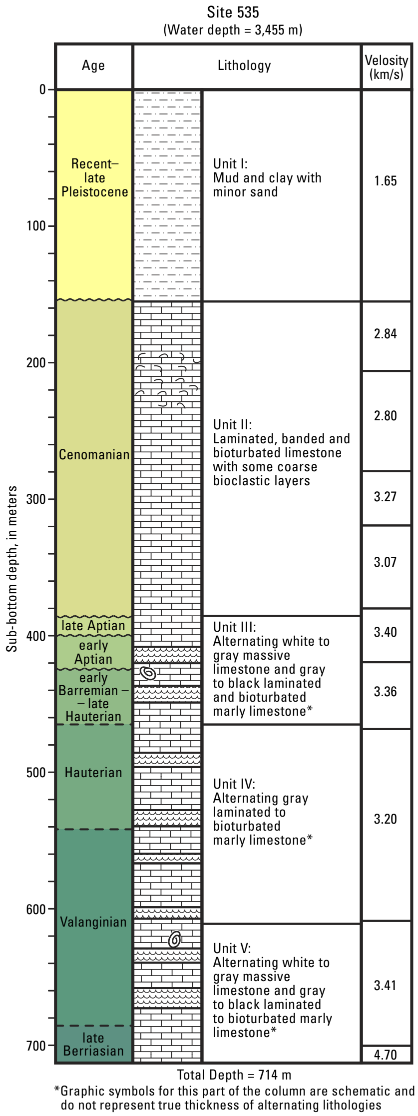

Figure 31. Interpretation of carbonate strata cored at Deep Sea Drilling Project Site 535 (from Herbin and others, 1984).

The well at DSDP Site 535 was drilled in a water depth of 3,455 m. Coring recovered approximately 714 m of sedimentary rock, mostly carbonates (figs. 30, 31). The cores began in Holocene and upper Pleistocene siliciclastic sediments, and at a sub-sea depth of 287 m drilling found possible Cenomanian carbonates, followed by Aptian, Barremian, Hauterivian, and Valanginian carbonates. Drilling was terminated in upper Berriasian carbonate rocks (fig. 31). These cores have been examined in detail for petroleum source-rock potential (Herbin and others, 1984; Katz, 1984; Palacas and others, 1984a; Patton and others, 1984; Rullkotter and others, 1984; Summerhayes and Masran, 1984).

The Cretaceous rocks cored at DSDP Site 535 were described as deep-water carbonates, mainly laminated to nonlaminated limestones with increasing percentages of organic material providing a darker color to the rock. The rocks ranged from white nonlaminated limestones to white and gray to dark gray laminated limestones (Herbin and others, 1984). Several studies analyzed the cores for TOC, which is an indicator of petroleum source rock potential. In general, the darker laminated limestones contained more organic carbon than the lighter laminated limestones. The majority of the cored interval, from the late Barremian to the Cenomanian, was interpreted to have good to excellent petroleum source rock potential (fig. 27). In general, TOC values above 0.5-1 weight percent are considered adequate for a petroleum source. This condition was met in the gray to dark grey laminated limestones but not in the laminated to nonlaminated white limestones (Katz, 1984).

The organic matter analyzed from these Cretaceous limestones is nearly all marine-derived, oil-prone Type II organic matter (Herbin and others, 1984). Little Type III, or woody nonmarine, gas-prone organic matter was observed in the cores. All of the studies cited herein show a preponderance of Type II and Type IIS marine organic matter (fig. 32).

The limestones cored at DSDP Site 535 were interpreted to be thermally immature with respect to petroleum generation, because measurements of vitrinite reflectance in all cores from Site 535 were less than 0.5 percent. Other geochemical parameters such as biomarkers also indicate thermal immaturity of the petroleum (Palacas and others, 1984a). The immaturity of the organic matter in the limestones is significant in that the oil stains and asphalt observed in the cores (fig. 33) must have originated from a fluid that migrated from a source rock that is mature in some other, deeper part of the basin. The fold and thrust belt is the likely source (Patton and others, 1984). Because oil was observed at Site 535, it is an indication that oil likely migrated from deeper parts of the basin, possibly from the eastern, deeper part where the

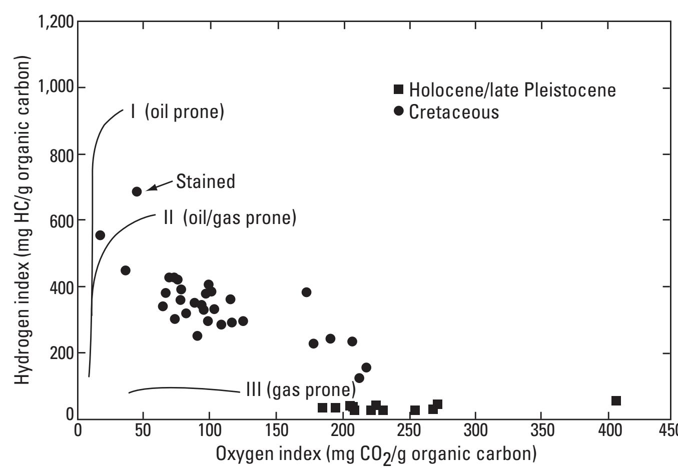

Figure 32. Modified van Krevelen diagram for potential hydrocarbon-bearing source rocks at Deep Sea Drilling Project Site 535. Potential source rocks contain predominantly Types II and III organic matter (from Katz, 1984). Mg HC/g, milligrams of hydrocarbons per gram of organic carbon; mg CO2/g, milligrams of carbon dioxide per gram of organic carbon.

Lower Cretaceous limestones are thermally mature enough to generate and expel petroleum.

Although the origin of the oil stains and asphalt at Site 535 is problematic, several studies indicate that the oil came from mature carbonate source rocks in the deeper part of the North Cuba Basin. The source rocks may be from thermally mature, deep-water limestones that are downdip or deeper than the rocks at Site 535, or the source may be from rocks stratigraphically deeper than these Neocomian rocks, including possible Jurassic sources (Palacas and others, 1984a). Moretti and others (2003b) concluded that the oil analyzed from DSDP Site 535 originated from a source within the North Cuba Basin and showed geochemical similarities to some oils analyzed from the Cuban onshore fields, but was distinct from similar age oils reported from the South Florida Basin (Palacas and others, 1984b).

Analyses of cores samples of Cretaceous limestones from DSDP Site 535 thus demonstrate that Cretaceous deep-water limestones have good to excellent petroleum source rock potential, and that these lithologies should be present to the east in the deeper parts of the North Cuba Basin. If thermally mature, these organic-bearing carbonates would make potential sources for oil not only in the North Cuba Thrust Belt AU but also in the North Cuba Foreland Basin AU and North Cuba Platform Margin Carbonate AU.

Significance of the Doubloon Saxon #1 Well, Bahama Platform

In 1986 a deep well was drilled to test the oil and gas potential of the southwest edge of the Bahama Platform near Cuba (Walles, 1993). The well was drilled to a depth of 6,631 m and remains (2008) the deepest test on the Bahama Platform. Several other wells have been drilled there over the years, but the area remains lightly explored for oil and gas (fig. 34). The Doubloon-Saxon #1 well was drilled on the edge of the carbonate platform, finding carbonate rocks to total depth. Unlike the carbonates in DSDP Site 535, there were few intervals of potential petroleum source rock, and all potential sources were higher in the Upper Cretaceous section. However, oil shows were recorded throughout much of the Lower Cretaceous carbonate section (fig. 35). The Cretaceous rock below a depth of about 5,000 m consisted of alternating carbonates and anhydrite beds. Walles (1993), in a post-drilling summary of this well, concluded that anhydrite beds above this depth were removed by dissolution—that is, flushing of the carbonate rock and dissolution of evaporate was by meteoric waters brought down along faults related to the collision of Cuba with the Bahama Platform. He also concluded that above a depth of 5,000 m, dissolution of anhydrite beds resulted in a loss of seals to any potential

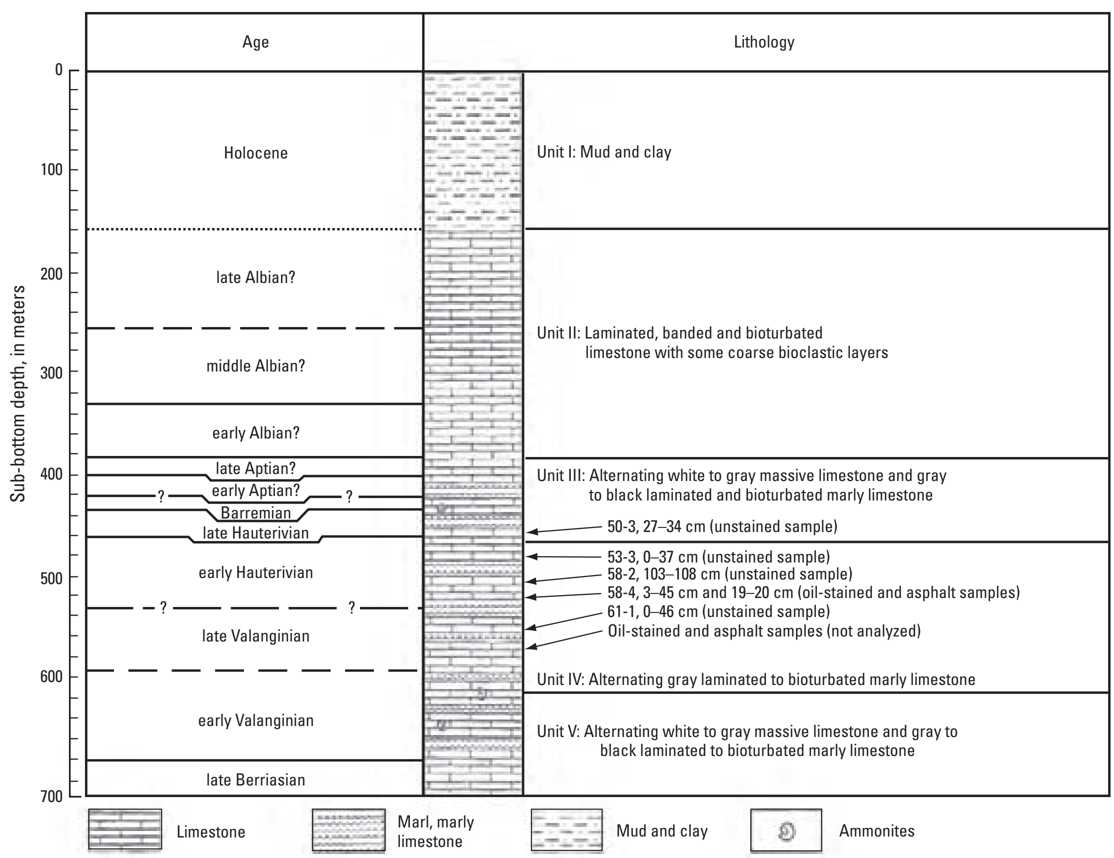

Figure 33. Stratigraphic column for Deep Sea Drilling Project Site 535 core showing location of oil-stained intervals in core that was sampled and analyzed by the U.S. Geological Survey (from Palacas and others, 1984a).

hydrocarbon accumulations, greatly reducing the potential for commercial oil accumulations to exist. Much “dead oil” was observed in the cores above 5,000 m, but deeper rocks contained “live oil”. Above 5,000 m, Walles (1993) believed there to be no structural trapping of oil and gas at this well site.

The presence of petroleum along the southwest edge of the Bahama Platform, however, is significant for the definition of the Jurassic-Cretaceous Composite TPS in the North Cuban Basin. In addition to the Doubloon-Saxon #1 well, petroleum was observed in several other wells in the Bahama Platform (fig. 35). Although no commercial oil accumulations have been reported, the presence of oil demonstrates that petroleum was generated and migrated into carbonate rocks of the platform. In addition, because apparently there are no potential petroleum source rocks in the Bahamian Platform carbonates, which is unlike similar age carbonates of the South Florida Basin (Palacas and others, 1984b), the oil must have (1) originated from deeper stratigraphic intervals (possibly of Jurassic age) within the platform; or (2) the oil originated lateral to the platform, possibly within the Cuban fold and thrust belt. Oil shows in the Doubloon-Saxon #1, Cayo Coco, and Cay Sal wells (figs. 34, 35) indicate that petroleum fluids migrated into the carbonates from below, possibly from a Jurassic source, or laterally from Jurassic or Cretaceous sources or both within the fold and thrust belt. There are no publicly available geochemical data that would bear directly on the origin of the Bahamian oils or on possible migration paths. Seals appear to be the main geologic risk above 5,000 m depths.

Live oil at depth is significant because if there are structures at depth or diagenetic traps, then oil or gas accumulations along the margin of the Bahama Platform are possible or even highly probable, given the depth where oil has been observed and the low geothermal gradients common to carbonate platforms.

Summary—Jurassic-Cretaceous Composite Total Petroleum System

A large body of geochemical data strongly indicates that several petroleum source rock units are present in the North Cuba Basin (Moretti and others, 2003b). The source rocks may be thermally mature at depth in the fold and thrust belt and in the deeper parts of the foreland basin, but the shallower, stratigraphic intervals of potential Cretaceous source rocks to the west of the fold and thrust belt are not thermally mature. Petroleum from the thrust belt and from the foreland basin might have migrated updip into traps in the thrust belt and in the foreland basin (Lopez-Rivera and others, 2003a, b), and possibly also migrated laterally to the margins of the Yucatan and Bahama carbonate platforms. Oil shows in core from DSDP Site 535 and from wells along the southwest margin

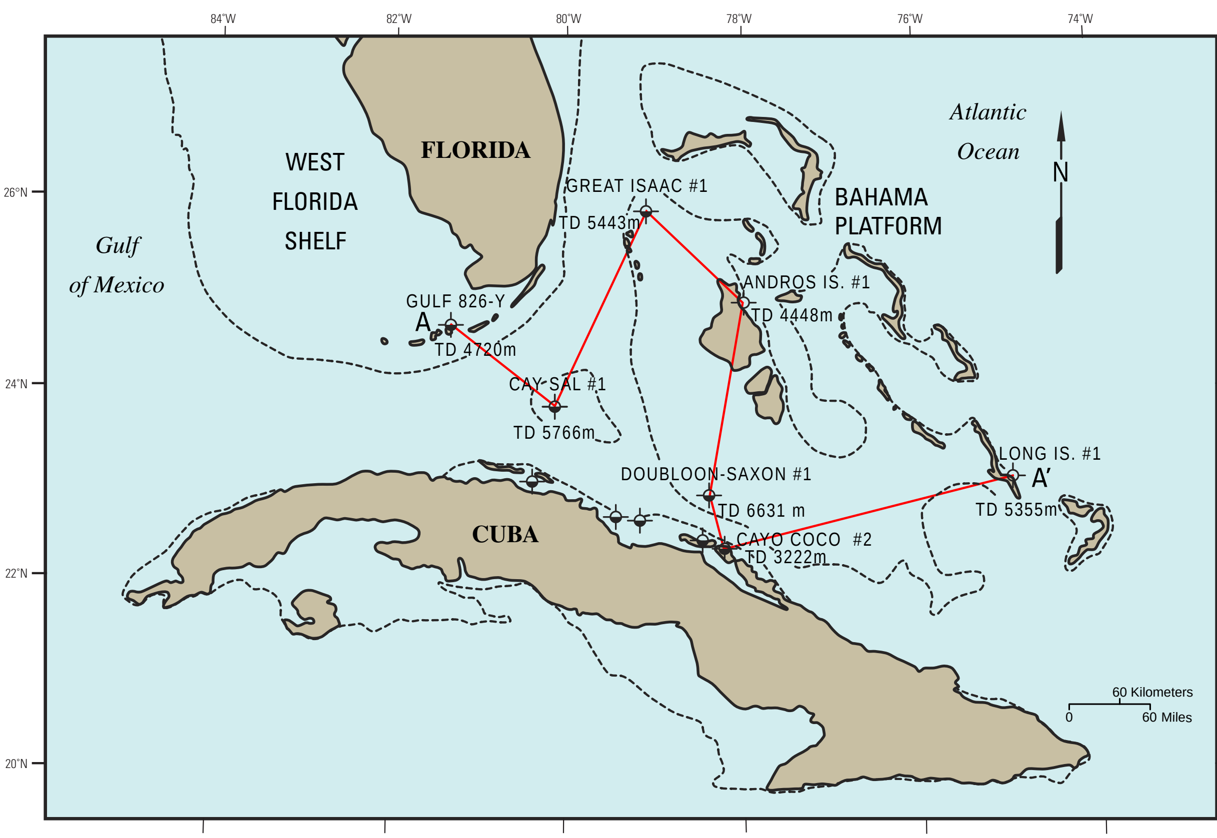

Figure 34. Map showing locations of oil and gas exploration wells in the southwestern part of the Bahama Platform (from Walles, 1993). Cross section A-A' shown in figure 35

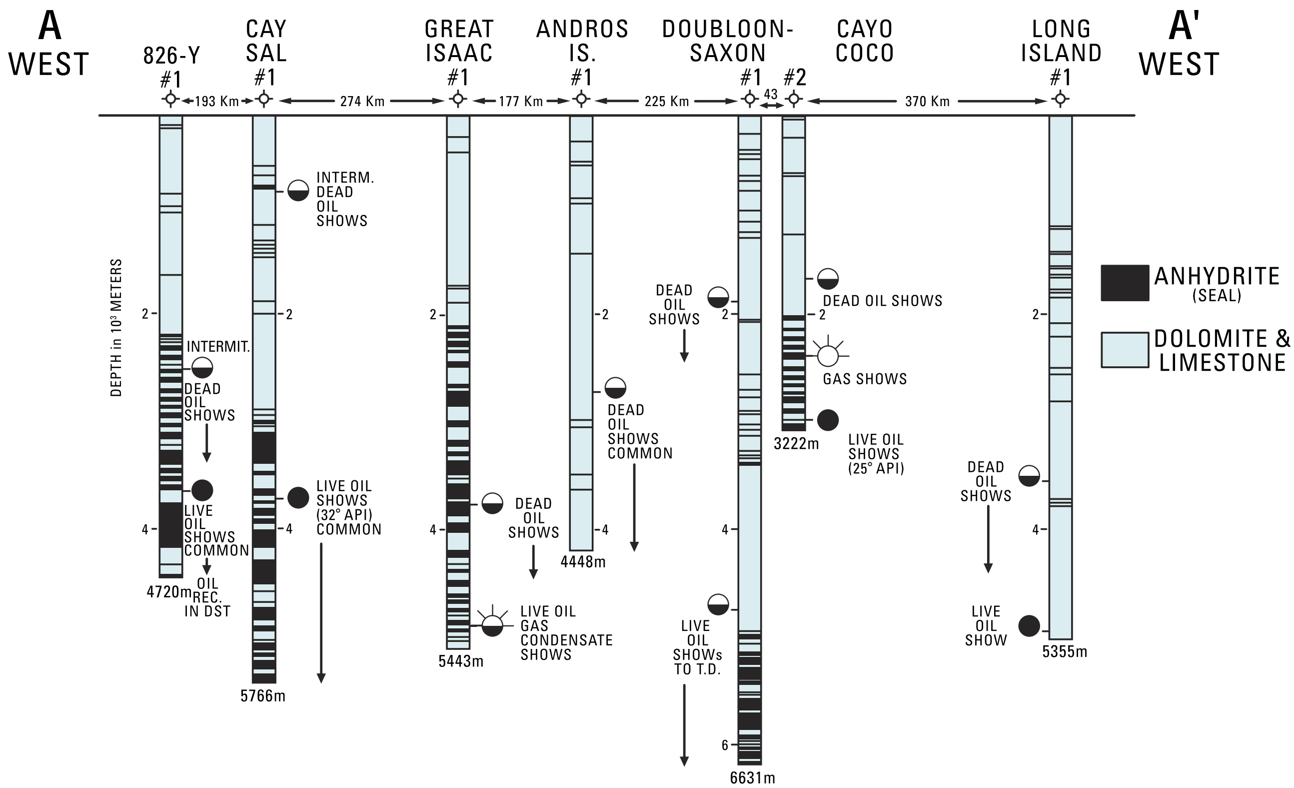

Figure 35. Cross section of wells drilled and tested in the Bahama Platform showing live oil and gas shows in most wells (from Walles, 1993). Line of section shown in figure 34. Intermit, intermittent; REC., recovered; DST, drill-stem test; T.D., total depth.

of the Bahama Platform indicate that migration of petroleum occurred within this composite total petroleum system. Although oil is the hydrocarbon found in the onshore fields in Cuba, oil and nonassociated gas accumulations might be present in the deeper parts of the thrust belt and in the foreland basin.

Geologic Definition Of Assessment Units

Three assessment units were defined within the Jurassic-Cretaceous Composite TPS—North Cuba Fold and Thrust Belt AU, North Cuba Foreland Basin AU, and the North Cuba Platform Margin Carbonate AU (fig. 36)—based on the main reservoir and trapping types within the TPS (fig. 37). The TPS boundary is imprecise because little drilling data are available from the offshore to indicate the possible updip limits of petroleum migration. Likewise, the AU boundaries are considered to be general, again because of the lack of definitive geologic information presently available from the offshore area. The three AUs are described in the following paragraphs.

North Cuba Fold and Thrust Belt AU

The North Cuba Fold and Thrust Belt AU, which encompasses all reservoirs within potential structural traps of the fold and thrust belt, is mainly onshore, but a part includes some offshore areas (fig. 38). All of the known oil and gas fields of the North Cuba Basin lie within this AU. The source for petroleum is interpreted to be primarily from Upper Jurassic to Lower Cretaceous organic-bearing carbonates, but synrift mudstones, Upper Cretaceous carbonate mudstones, and Paleogene mudstones also might have contributed petroleum to this system.

The North Cuba Fold and Thrust Belt AU contains up to 12 km of Jurassic through Cretaceous carbonate rocks (Hernandez-Perez and Blickwede, 2000), which host the largest oil fields in Cuba (Valledares-Amaro and others, 2003a,b). The AU is dominated by structural traps, mainly folds, fault-related folds, faulted anticlines, and duplex structures (fig. 39). The structures have been investigated for decades and many exploration plays have been developed within the fold and thrust belt (fig. 40). Seismic data generally illustrate a stack of thrust sheets forming the thrust belt (fig. 41). Stratigraphic traps might be present, but they are not considered to be significant in this AU. All of

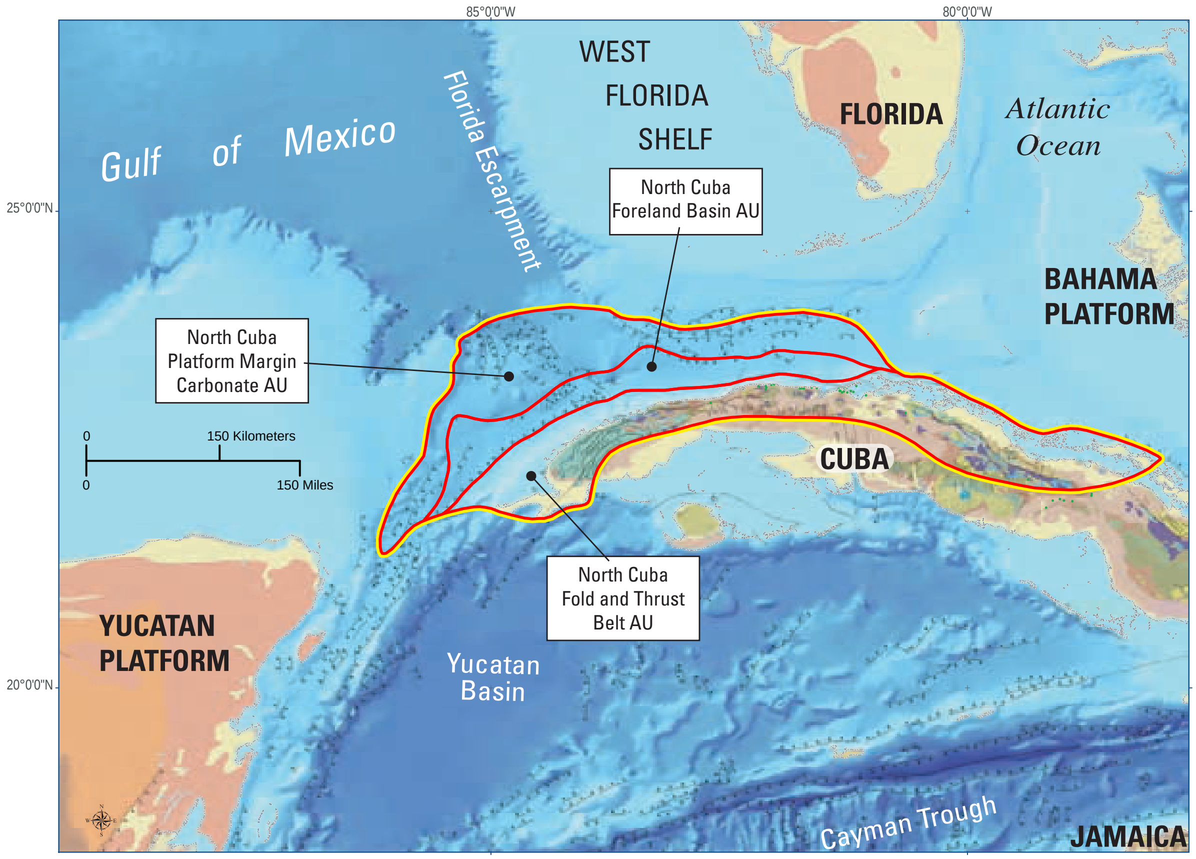

Figure 36. Boundaries of the three assessment units (AU) defined for this study. Note that the assessment units do not overlap and are contained within the Jurassic-Cretaceous Composite Total Petroleum System (yellow line).

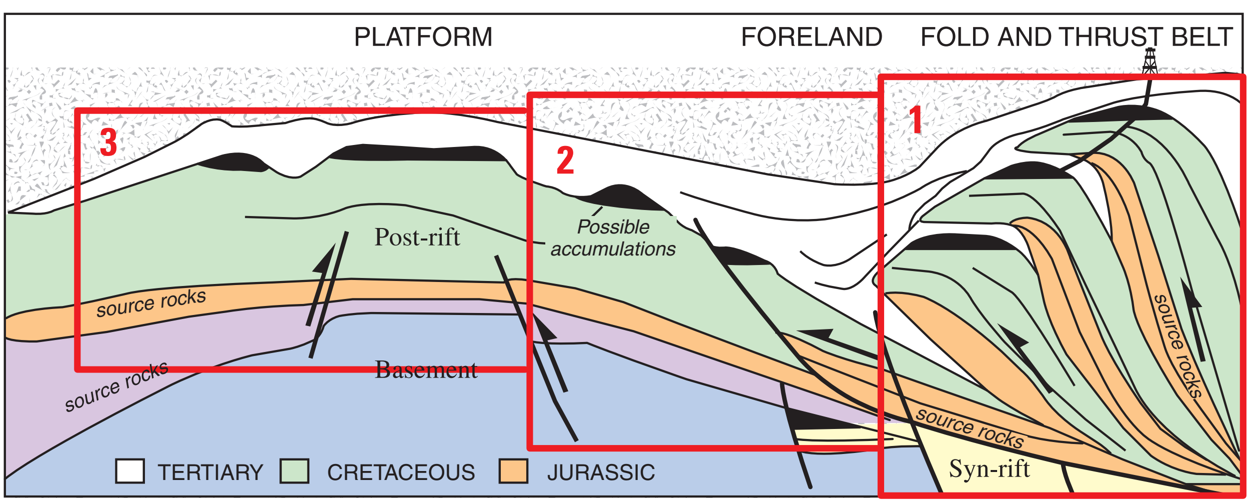

Figure 37. Schematic structural cross section of the North Cuba Basin showing general boundaries and characteristics of the three assessment units (AU) defined in this study. 1, North Cuba Fold and Thrust Belt AU; 2, North Cuba Foreland Basin AU; 3, North Cuba Platform Margin Carbonate AU (modified from Moretti and others, 2003b).

the known fields in this AU either produce or have produced from reservoirs within structural traps, and several published examples of fields have documented the structural complexity of fields within the Cuban fold and thrust belt (figs. 42, 43). The oil in most of the reservoirs is heavy (API gravity less than 20 degrees), and the low gravities might be due to biodegradation related to the shallow depth of most reservoirs (Campos-Jorge and others, 1994).

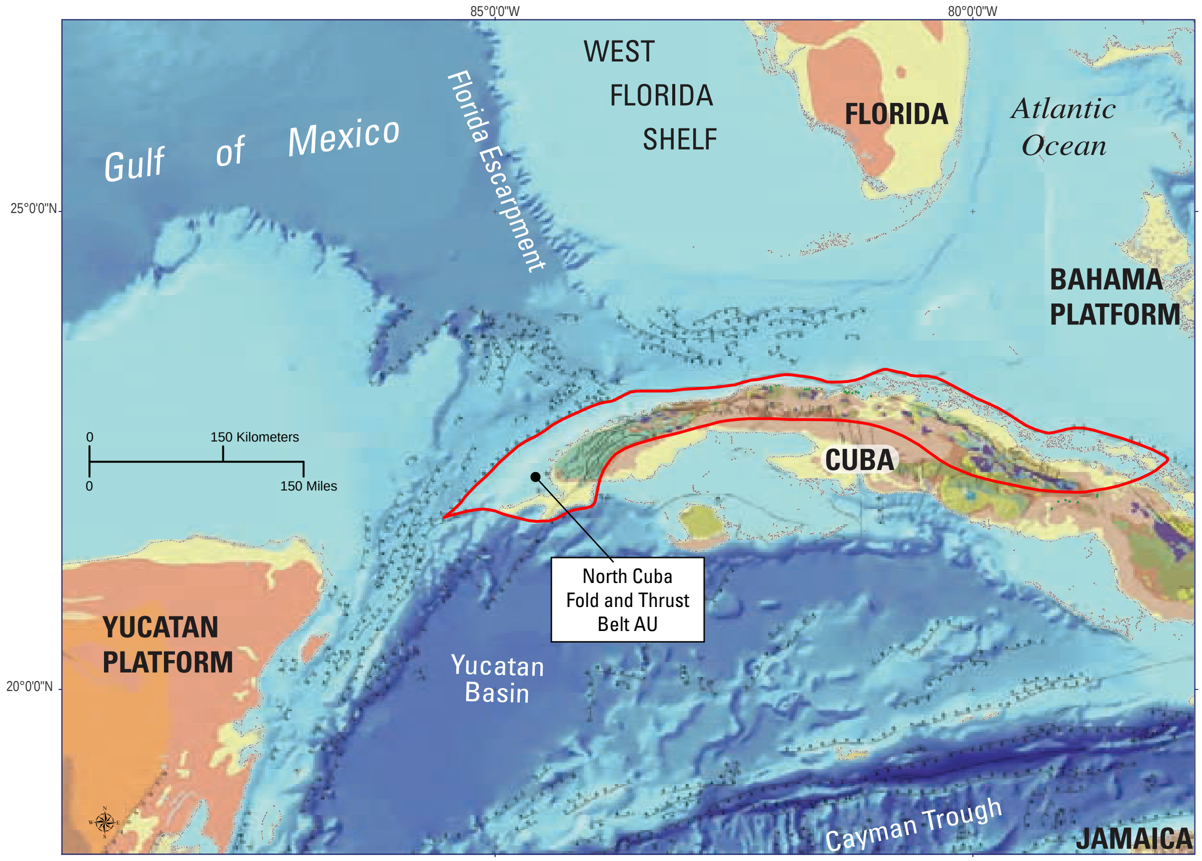

Figure 38. Boundary of the North Cuba Fold and Thrust Belt Assessment Unit. All known oil fields in northern Cuba are located within this assessment unit.

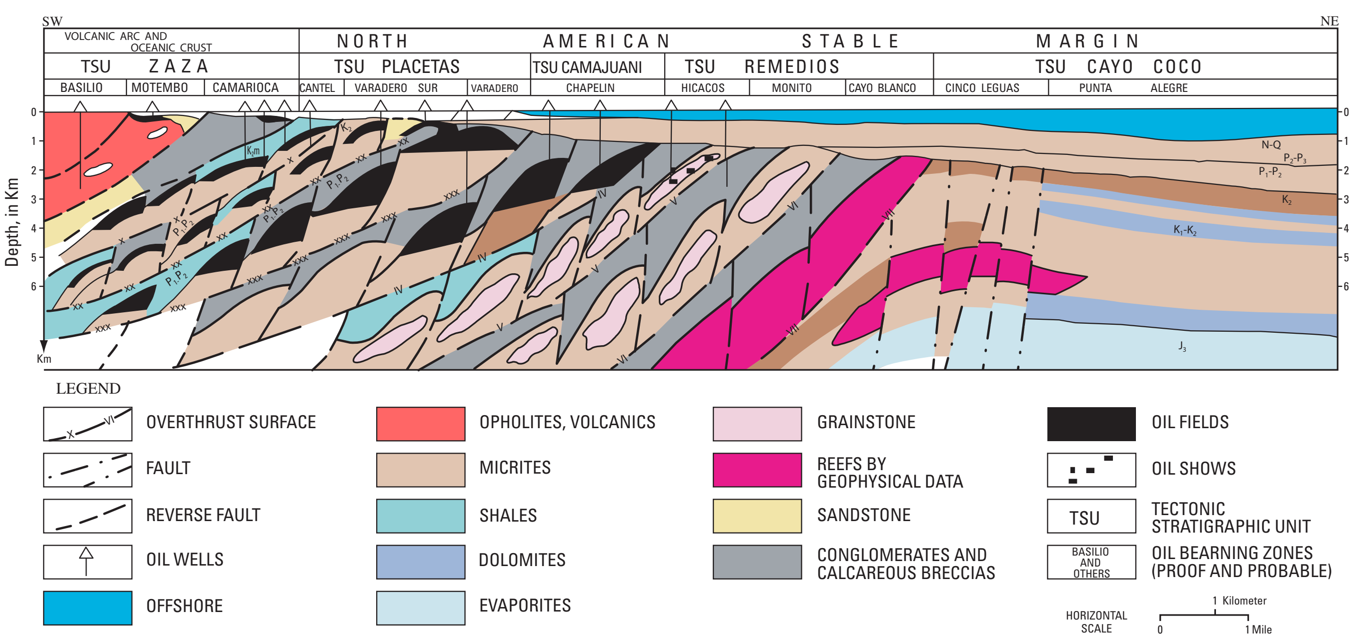

Figure 39. Schematic geologic cross-section across onshore northwestern Cuba showing complexity of thrust faulting and its relation to onshore oil and gas fields in the North Cuba Fold and Thrust Belt Assessment Unit (after Echevarria-Rodriguez and others, 1991).

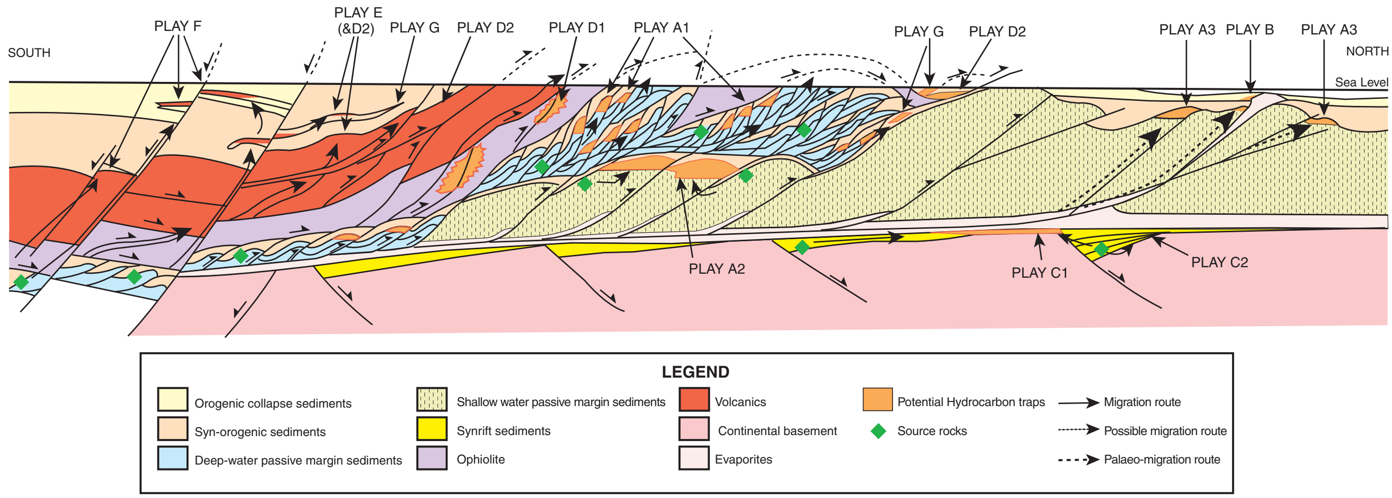

Figure 40. Schematic geologic cross section illustrating the complex structure of the North Cuban Fold and Thrust Belt and the rift zone underlying the fold belt, and the definition of oil and gas exploration play types (from Cubapetroleo, 2002).

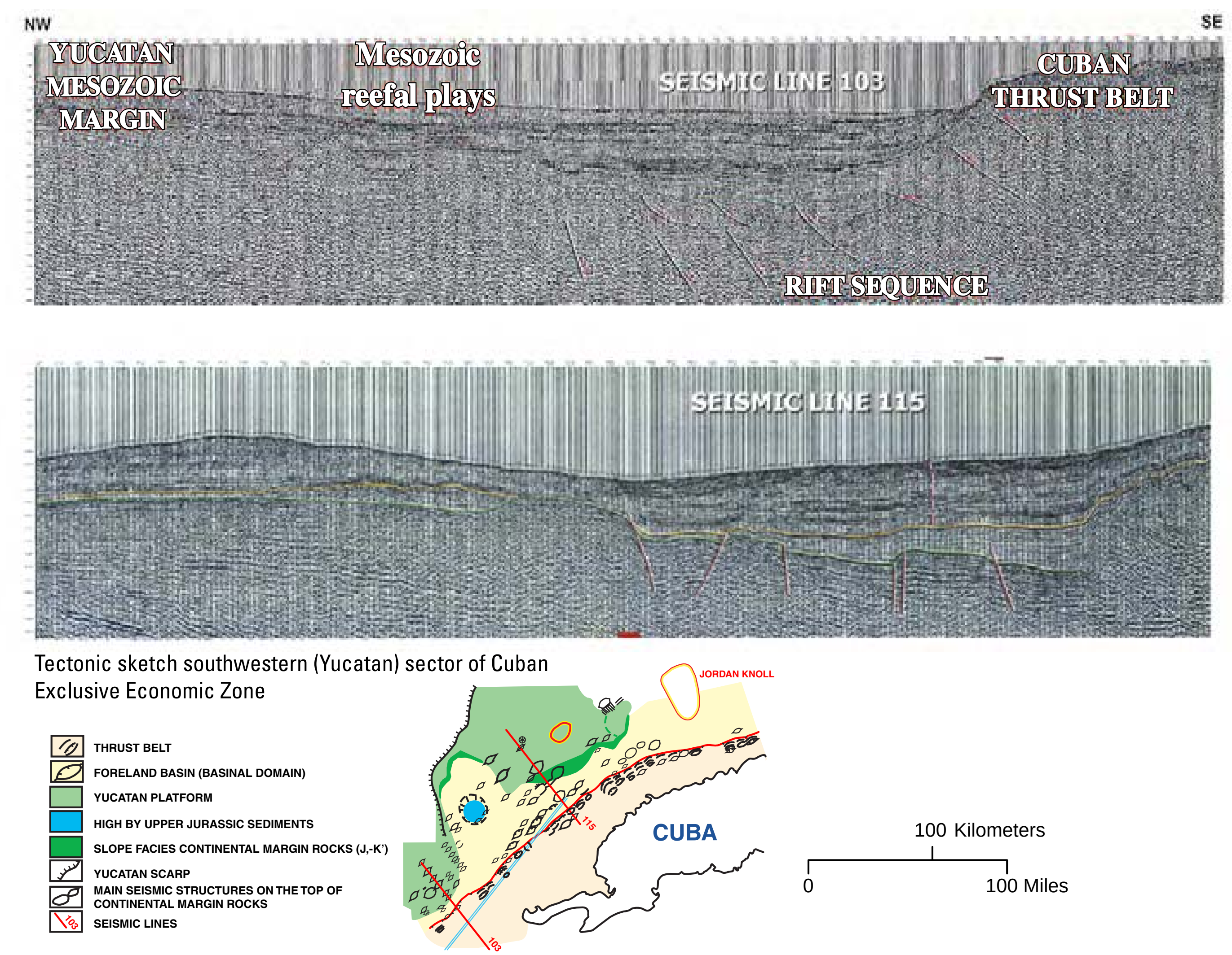

Figure 40

Figure 41. Two selected seismic sections showing general expression of the North Cuba Fold and Thrust Belt, foreland, and margin of the carbonate platform (from Lopez-Rivera and others, 2003a). The foreland basin structures in Line 115 might have been inverted during the Paleogene compressional event.

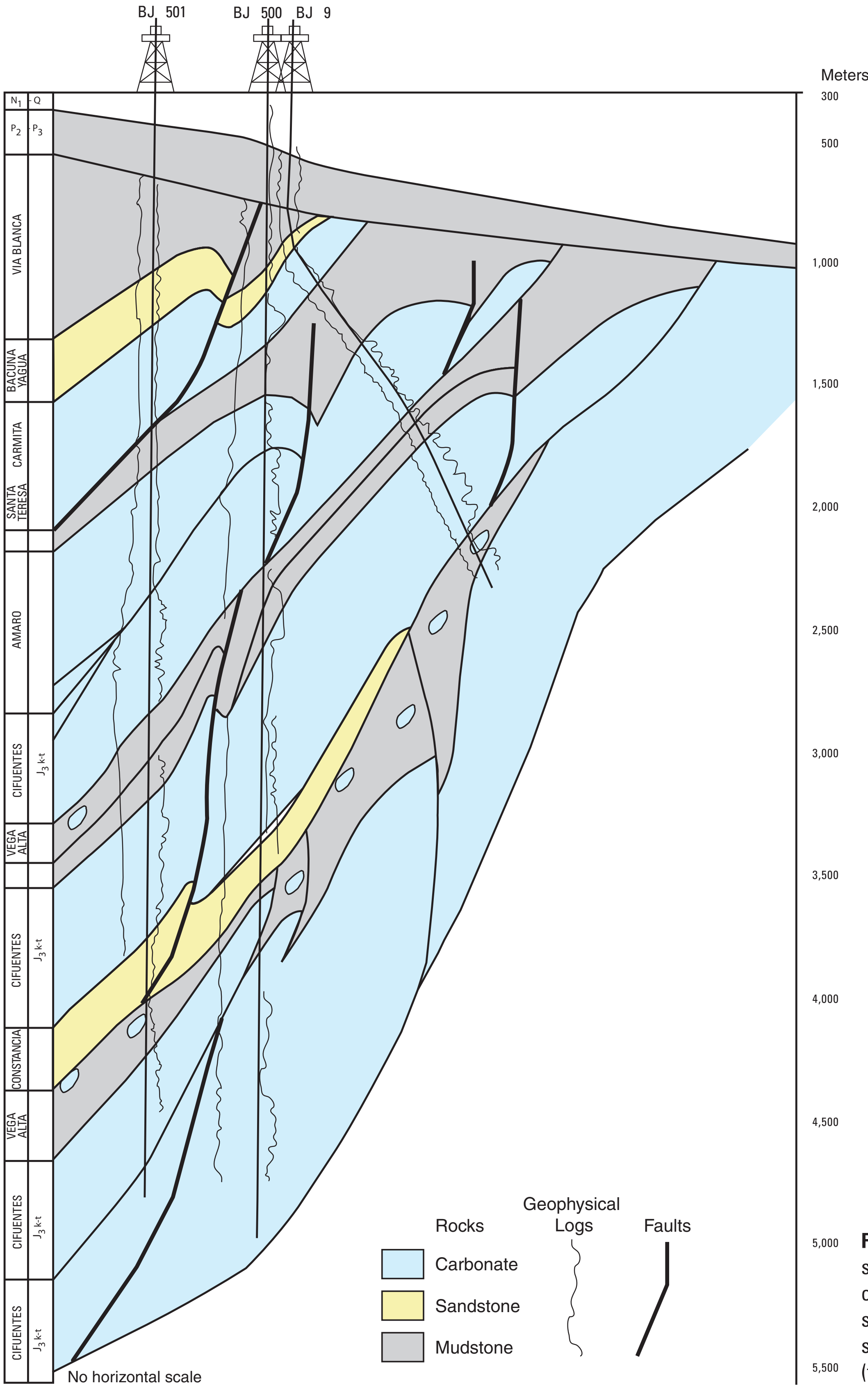

Figure 42. Structural cross section of the Boca de Jaruco oil field in northern Cuba showing the complexity of the structures in the thrust belt (from Campos-Jorge and others, 1994). Well logs are shown along the well paths.

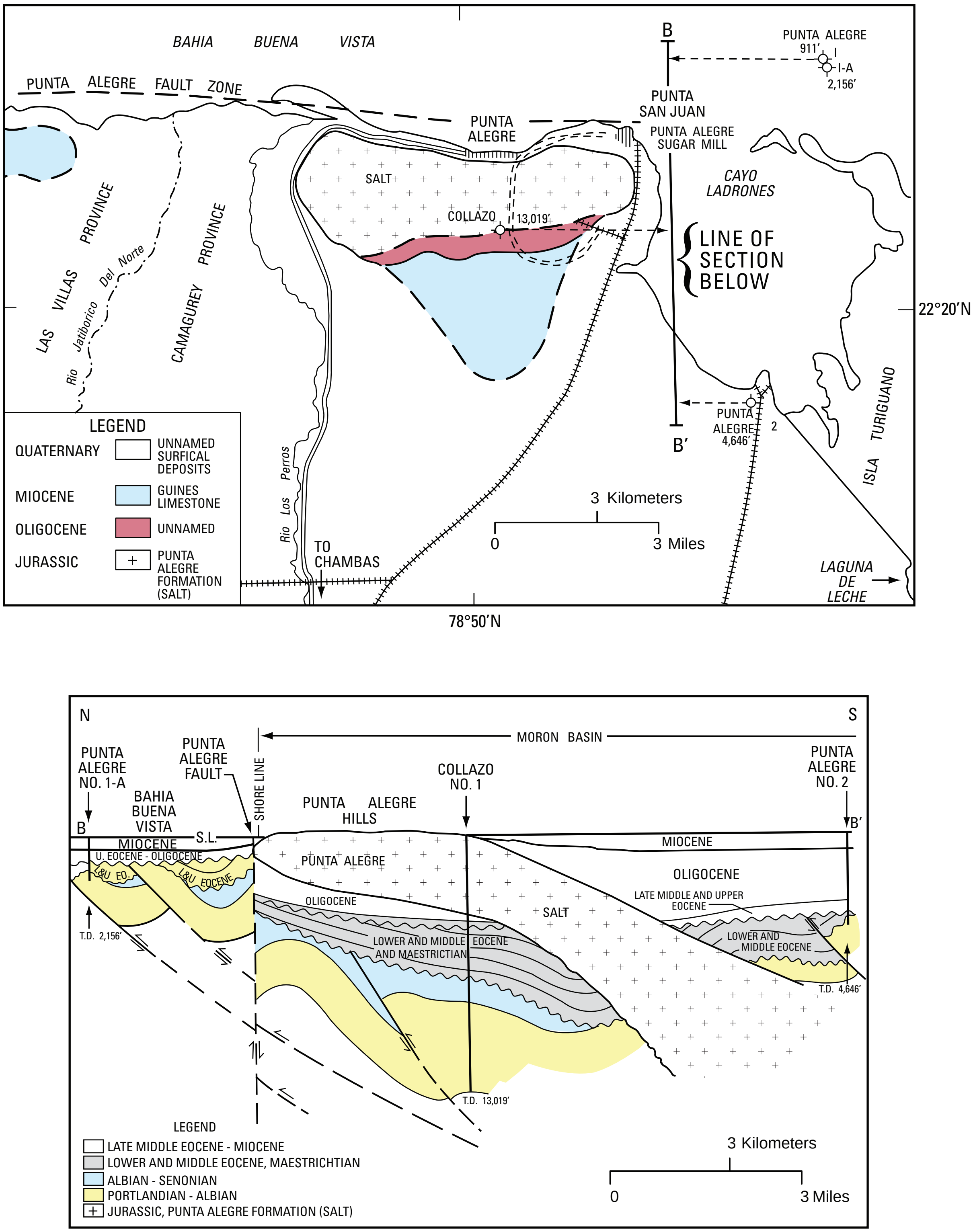

Figure 43. Structural cross section of the Punta Alegre oil field, northern Cuba (from Ball and others, 1985).

Reservoirs in this AU are reported to be nearly all fine-grained carbonate rocks associated with structural traps. Fractures that formed during thrusting appear to be essential in developing porosity and permeability in carbonate rocks. Little published information is available on reservoir quality. However, Brey del Rey and Hernanndez-Leon (1998) concluded that diagenesis is complex in these carbonates, and that secondary porosity developed at depth is important for improving reservoir quality. Some of the Cretaceous platform carbonates might have been subjected to karst-forming processes, which also would enhance reservoir quality (Valledares-Amaro and others, 2003a, b).

The geologic model for this AU includes (1) structural trapping of oil and possibly gas that was generated within the fold and thrust belt (fig. 44); and (2) vertical migration into complex structures, where the shallow depth of many reservoirs led to degradation of the hydrocarbons, resulting in low API gravities. The events chart summarizing the geologic elements for this AU is shown in figure 45.

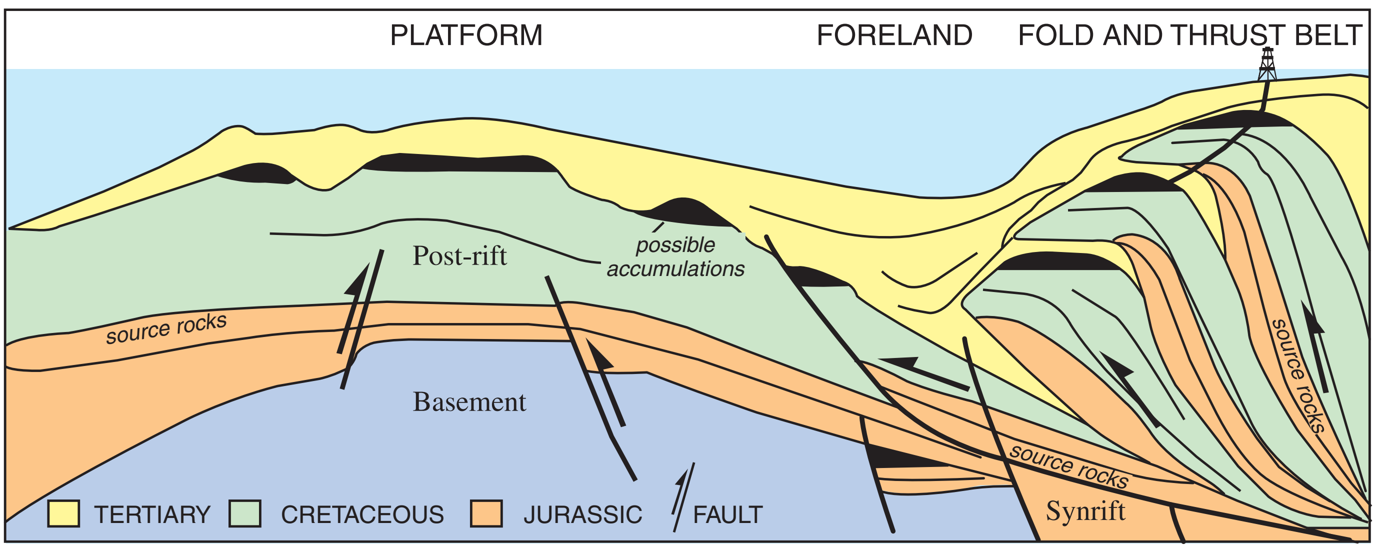

Figure 44. Geologic model for assessment of undiscovered petroleum resources in the Jurassic-Cretaceous Composite Total Petroleum System (from Moretti and others, 2003b).

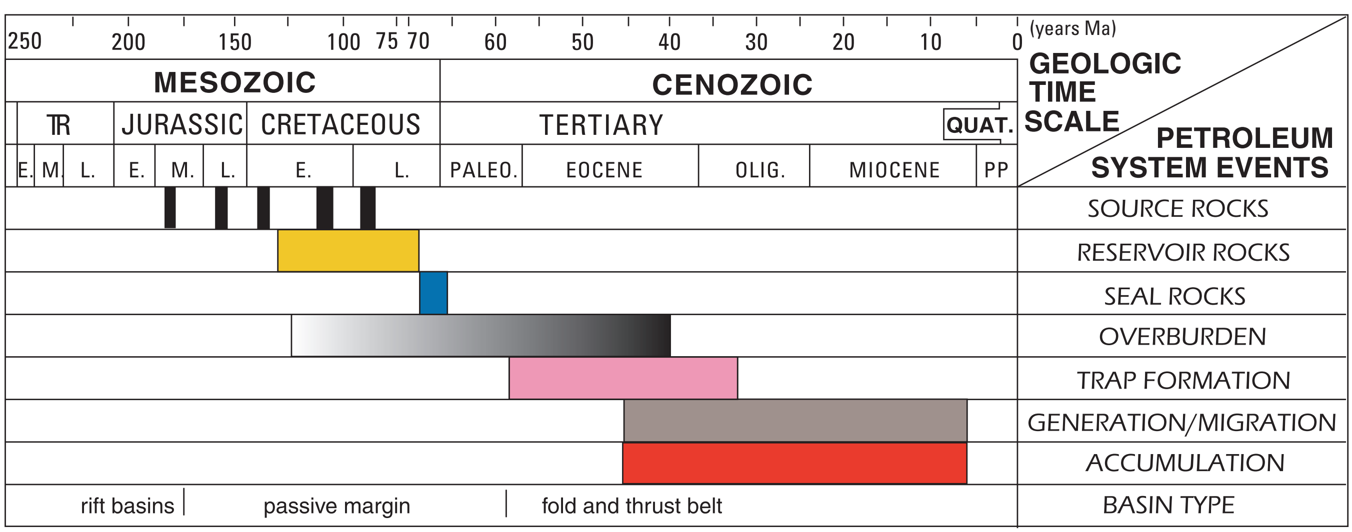

Figure 45. Events chart for North Cuba Fold and Thrust Belt Assessment Unit.

North Cuba Foreland Basin AU

The North Cuba Foreland Basin AU encompasses all reservoirs in the foreland basin part of the North Cuba Basin (fig. 37), including potential reservoirs in the deeper, rift-related part of the AU (fig. 46). This AU is entirely offshore, and to date (2008) only one well has been drilled; the well reportedly penetrated rock with light hydrocarbons but no more is presently known about the test results. Trapping in this AU is interpreted to be mostly structural (fig. 44), with structures formed as a result of: (1) rifting in the Triassic and Jurassic; (2) extensional structures in the Mesozoic; (3) extensional structures inverted in the Paleogene compressional event (Letouzey and others, 2003); and (4) folds in foreland-basin strata. Stratigraphic traps might be present in clastic rocks of the foreland, because the south-dipping clastics might form updip pinch-out traps (Hernandez-Perez and Blickwede, 2000).

Reservoirs in the North Cuba Foreland Basin AU, although in the hypothetical category, are interpreted to be mainly in carbonate rocks. In the area that is now the foreland (and within this AU), a shallow-water carbonate “megabank” existed during the Aptian and early Albian time (Denny and others, 1994). This feature was subaerially exposed in the late Albian, most likely because of a sea-level drop, and the exposed surface was extensively karsted, which would have resulted in excellent porosity at this stratigraphic level (Valladares-Amaro and others, 2003a,b). Subsequently, the megabank foundered and broke up, and the blocks were covered by finer grained sediments (Denny and others, 1994; Chambers and others, 2003; Sanchez-Arango and others, 2003). Under these conditions, many reservoirs with zones of excellent porosity might have formed, all of which then were sealed by finer grained rocks. Reservoirs also might be present in the deep synrift grabens that underlie the foreland basin.

Modeling indicates that some of the potential source rocks in the North Cuba Foreland Basin AU might have passed into the thermal generative windows for oil and gas, but there is considerable uncertainty as to the hydrocarbon phase that might exist in this AU. An estimate was made that the hydrocarbon phase of undiscovered fields would be 90 percent oil fields and 10 percent gas fields. The events chart summarizing the main geologic elements of for this AU is shown in figure 47.

North Cuba Platform Margin Carbonate AU

The North Cuba Platform Margin Carbonate AU encompasses all potential reservoirs developed in carbonate platform-margin environments along the Yucatan and

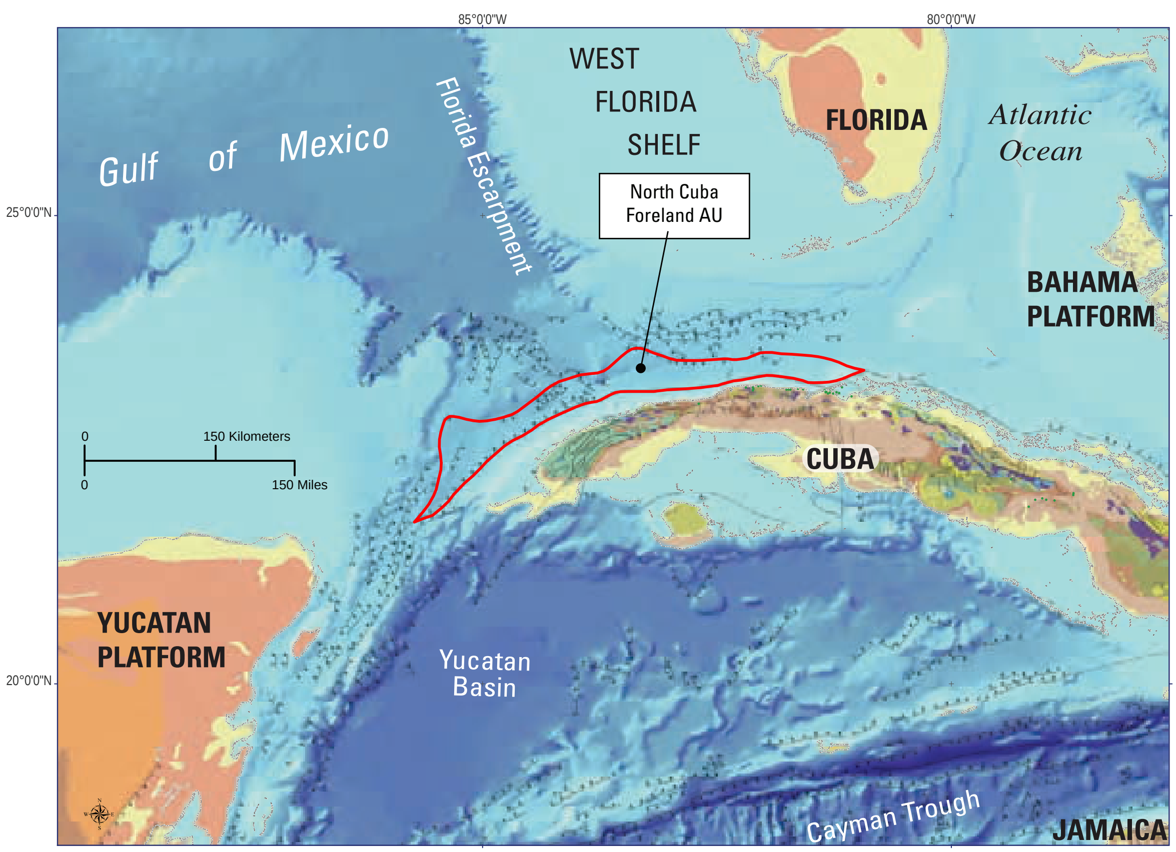

Figure 46. Boundary of the North Cuba Foreland Basin Assessment Unit.

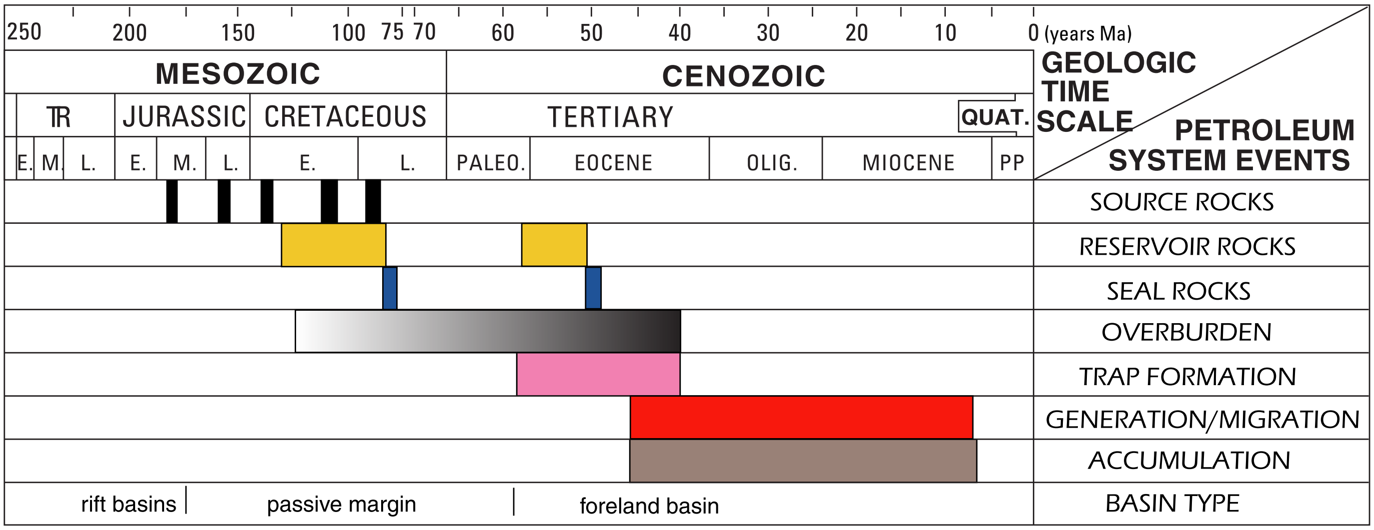

Figure 47. Events chart for the North Cuba Foreland Basin Assessment Unit.

Bahama margins (fig. 48). The area of this AU is somewhat limited compared to the other AUs, but the potential reservoirs—including reef, fore-reef, and carbonate debris-flow reservoirs—might be prolific. These reservoirs might be stacked, because the platform margin remained relatively stable from the Late Jurassic through the Cretaceous.

By analogy, carbonate reservoirs are well known in equivalent-age rocks from the southern Gulf of Mexico (Enos, 1977; Enos and Moore, 1983; Cook and Mullins, 1983; Magoon and others, 2001). Reef trends are well documented around the Gulf Coast (McFarland and Menes, 1991), especially in the Lower Cretaceous (fig. 49). Porosity can be high in these reservoirs and, as with all carbonate rocks, porosity is largely dependent upon the diagenetic history of the rock. Fore-reef and debris-flow reservoirs are especially significant in the Mexican part of the Gulf of Mexico. Generally defined as Tamabra-like reservoirs (Magoon and others, 2001), these rocks contain some giant

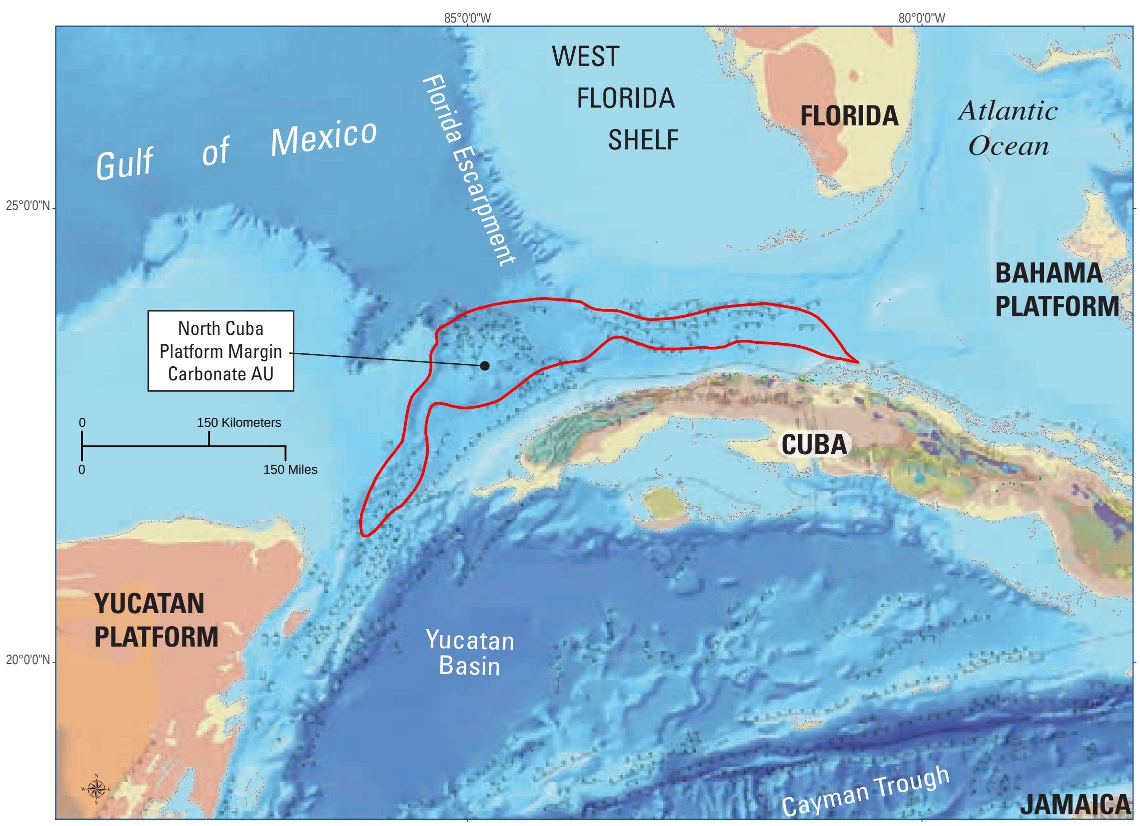

Figure 48. Boundary of the North Cuba Platform Margin Carbonate Assessment Unit.

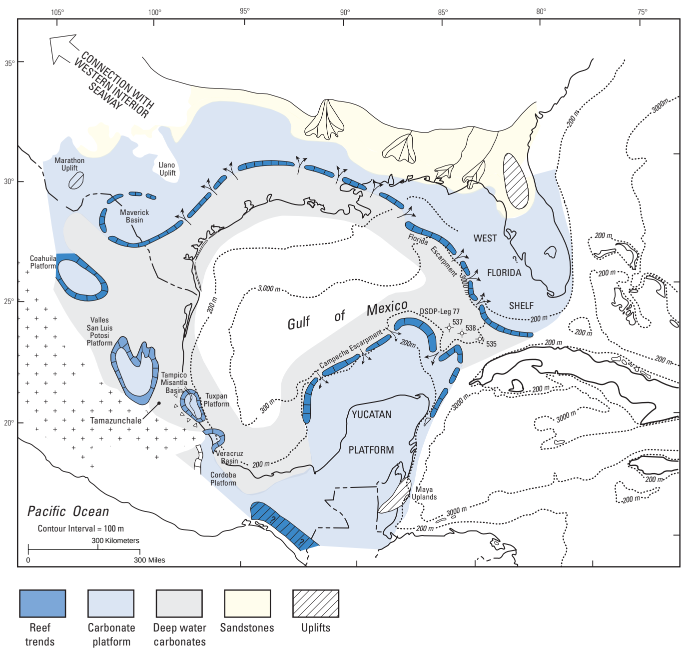

Figure 49. Paleoenvironmental map of the Albian showing the distribution of platform margin reefs and deep-water carbonate strata (from McFarland and Menes, 1991). DSDP, Deep Sea Drilling Project wells.

oil accumulations in the Mexican Gulf Coast. The reservoirs generally represent reef talus or debris flows of reef and shelf detritus that accumulated on the slope or in the basin, then they became encased in finer grained rocks that are excellent seals. Porosity can be high in these types of reservoirs. Reservoir porosity might have been enhanced by processes associated with sea-level drawdown in the Paleogene (Rosenfeld and Pindell, 2003).

The lack of drilling prevents anything more than general speculation as to the reservoir and trapping conditions that might exist in the North Cuba Platform Margin Carbonate AU, but, by analogy with those described above for the Mexican Gulf Coast; there is a high probability that geologic characteristics are similar. Another major source of geologic uncertainty is hydrocarbon migration and reservoir charge. For reservoirs to have been charged with oil, the oil must have been generated in the Fold and Thrust Belt or Foreland Basin AUs and then to have migrated laterally into potential reef, fore-reef, or slope-basin reservoirs. The only evidence for lateral migration of oil is the oil staining of carbonate rock in the DSDP Site 535 core. Questions remain as to how much fluid might have migrated, and whether there was enough fluid to adequately charge a potential reservoir of minimum size in this AU.

The petroleum phase in this AU is interpreted to be oil, but this interpretation involves considerable geologic uncertainty. Nonassociated gas was not assessed in this AU. The events chart summarizing the geologic elements for this AU is presented in figure 50.

Assessment of Undiscovered Oil and Gas Resources

Geologic Models for Assessment

Each AU is assessed separately using a geologic model that defines the geologic and petroleum-system elements and that incorporates any geologic constraints that bound the assessment. The geologic models are used to develop the probability distributions for sizes and numbers of undiscovered oil and gas fields in each AU.

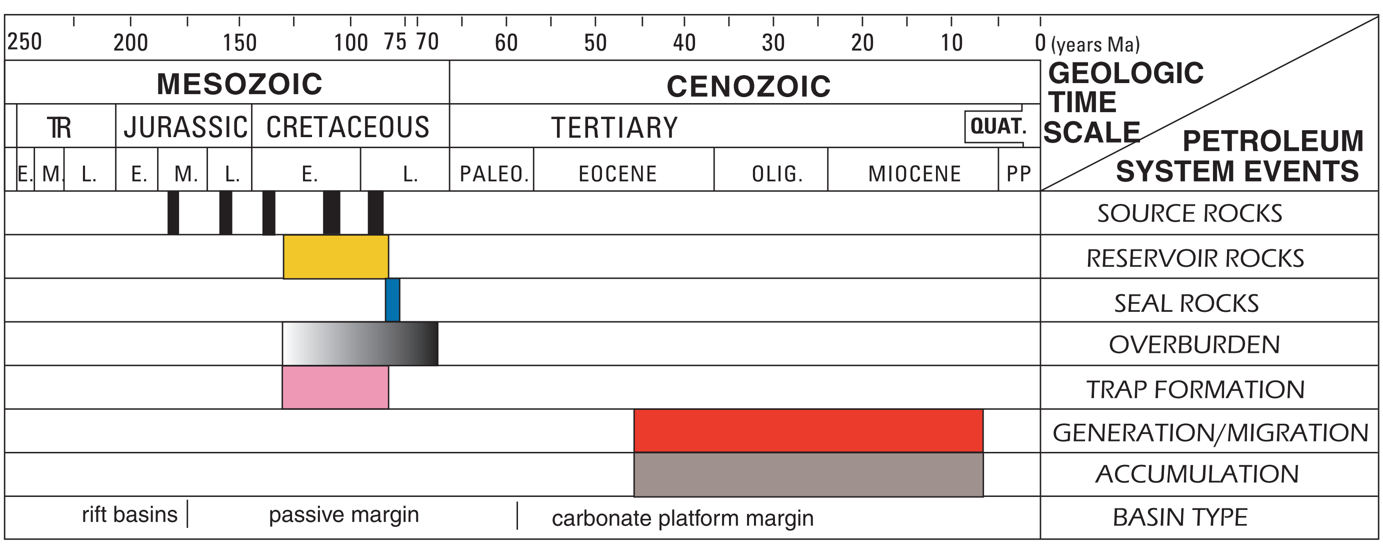

Figure 50. Events chart for the North Cuba Platform Margin Carbonate Assessment Unit.

North Cuba Fold and Thrust Belt AU

Petroleum, both oil and gas, generated in the Paleogene by thrust loading of Upper Jurassic and Lower Cretaceous source rocks, migrated vertically along faults and into carbonate reservoirs within the fold and thrust belt. Petroleum might be biodegraded in shallow reservoirs, but not in deeper accumulations. Although exploration has focused on the shallower accumulations, significant resources might be present in deeper reservoirs, including oil and nonassociated gas. Seals are provided by intraformational mudstones and possibly by diagenesis within the Upper Jurassic and Lower Cretaceous strata. This AU also might have reservoirs within synrift strata that potentially contain petroleum. There is a possibility that Paleogene source rocks might have contributed some petroleum, but volumes from this source are considered to be minor compared to those from the Upper Jurassic and Cretaceous source rocks. More than 20 oil fields have been discovered in this AU, but production data are not available for all fields, nor is the status of several fields presently (2008) known.

North Cuba Foreland Basin AU

Petroleum generated in the fold and thrust belt during Paleocene thrust loading and(or) petroleum generated from the deeper part of the foreland basin migrated vertically and laterally into carbonate reservoirs trapped in broad compressional structures, and within clastic reservoirs in the foreland basin sedimentary sequence. Potential reservoirs within the deep synrift section also are included in this AU, but models indicate that source rocks in the synrift section probably are overmature. Pooled petroleum is predicted to be oil and gas; some geochemical data from fields in the thrust belt indicate that thermally evolved or mature gas might be present in some reservoirs. Reservoirs in broad compressional structures may require fracturing for reservoir quality, because the carbonates generally comprise the fine-grained facies. Some of the carbonate rock in core from Site 535 is fractured, and the site is not in proximity to structure. Seals are predicted to be adjacent nonfractured fine-grained carbonates. Some of the carbonate rocks in this AU might have been subjected to karst-forming processes during the formation of the fold and thrust belt (Rosenfeld and Blickwede, 2006), and the karst zones could form adequate hydrocarbon reservoirs. However, the presence of adequate reservoir quality is a significant geologic risk in this AU.

There are no oil or gas fields in the North Cuba Foreland Basin AU. Only one well has been reported, and was drilled in the offshore in 2004 by the Spanish oil company Repsol. Although details of production tests are not available, Repsol announced that tests show that the well penetrated a noncommercial light-oil accumulation. Two delineation wells are planned, but have not been drilled as of early 2008.

North Cuba Platform Margin Carbonate AU

Petroleum generated by thrust loading of Upper Jurassic and Lower Cretaceous source rocks in the Paleogene during the formation of the fold and thrust belt would have to migrate laterally for some distance for it to have accumulated within reservoirs of this AU. The geologic model involves petroleum being generated in the thrust belt or possibly from the deeper part of the foreland basin, then migrating laterally into reservoirs formed along the margins of the Yucatan and Florida/Bahama carbonate platforms. Reservoirs are postulated to be largely reef, fore-reef, and carbonate debris-flow units along the platform margin, similar to the reservoirs in the Mexican part of the Gulf Coast (Magoon and others, 2001). These types of reservoirs are fundamental to petroleum systems of the Mexican Gulf Coast, and debris-flow reservoirs in particular might represent one of the highest quality reservoir types in the Jurassic-Cretaceous Composite TPS. Another reservoir type might be karst zones within the platform carbonates (Valladares-Amaro and others, 2003b), because karst might have developed during the formation of the fold and thrust belt (Rosenfeld and Blickwede, 2006).

Although the reservoir type is analogous, the distance of migration in the Mexican Gulf Coast example appears to have been less than in this composite TPS. Distance of migration required for the Cuban reservoirs might constitute a significant geologic risk in the estimation of undiscovered oil resources in this AU. No oil and gas fields are known from this AU, and there has been no exploration to date (2008).

Assessment Methodology

The methodology used in USGS assessment of conventional oil and gas resources is outlined by Schmoker and Klett (2002) and Klett and others (2002). In summary, for each assessment unit all available geologic and engineering information on the elements of the composite TPS are used to develop two probability distributions—one for sizes of undiscovered oil fields and the other for numbers of undiscovered oil fields. If nonassociated gas fields are to be assessed, then two distributions also are required for sizes and numbers of undiscovered gas fields. Sizes of undiscovered oil and gas fields are estimated using several kinds of information, including size distribution of known oil and gas fields, level of exploration within the AU, dry-hole analysis, information on calculated volumes within untested prospects, and distributions of field sizes and numbers from geologically analogous AUs. Each field-size distribution is constrained by a minimum size that is determined prior to the assessment (generally 1 million barrels oil [MMBO]; 6 billion cubic feet gas [BCFG]), and a maximum size determined by the assessor to constrain the upper end of the distribution. The assessor is asked for the median of the undiscovered field-size distribution. This value can be estimated, in part, by the median size of the known field-size distribution or by using field-size distributions from geologic analogs.

The distribution of numbers of undiscovered fields is difficult to develop without detailed seismic-based prospect maps and, consequently, there is much uncertainty with the estimation of numbers of undiscovered oil and gas fields. Several types of information are used as guides to develop distributions of numbers of undiscovered fields, including numbers of known fields, prospect maps, degree of exploration within an AU, space available within an AU for potential discoveries, and numbers of known fields within geologic analog AUs. Given the uncertainty, a wide range of estimates is provided on the input form (for example, Appendix 1 at the back of the report). The assessor is asked for a minimum number, maximum number, and a mode to define the probability distribution for numbers of undiscovered fields. This is done separately for oil and gas fields.

Once the probability distributions of undiscovered field sizes and numbers are developed, they are subjected to a Monte Carlo sampling and modeling approach, which randomly samples the two distributions 50,000 times to develop a summary distribution of volumes of undiscovered oil and gas resources. Oil and nonassociated gas fields are analyzed separately for sizes and numbers of undiscovered fields; associated gas and natural gas liquids (NGL) are calculated using co-product ratios. Assessment results are presented as a suite of fractiles (F95, F50, F5, and mean), for oil, nonassociated gas, associated gas, and natural gas liquids.

Assessment Input Data

North Cuban Fold and Thrust Belt AU

The development of the probability distribution for sizes of undiscovered fields in this AU is strongly guided by the sizes of its known oil fields, of which there are 16 oil fields in the database larger than minimum size (1 MMBO). The median size of these known fields is about 5.2 MMBO, and the largest, Boca de Jaruco, is estimated at about 140 MMBO (fig. 51). To define the probability distribution for undiscovered field sizes, the minimum is set at 1 MMBO and the median is set at 3 MMBO (Appendix 1); the latter indicates that the median size of potential undiscovered fields is predicted to be less than that of known fields (5.2 MMBO) as exploration continues, a common characteristic of oil and gas field exploration history. The estimate for the largest undiscovered field (with little probability of occurrence) is set at 300 MMBO, which suggests that there is a small probability that the largest oil field has yet to be found in this AU. There also is deeper potential for oil fields within the fold and thrust belt. Given a minimum oil field size of 1 MMBO, a median of 3 MMBO, and maximum of 300 MMBO, the Monte Carlo simulation calculates a “most likely largest undiscovered oil field size” of about 93 MMBO.

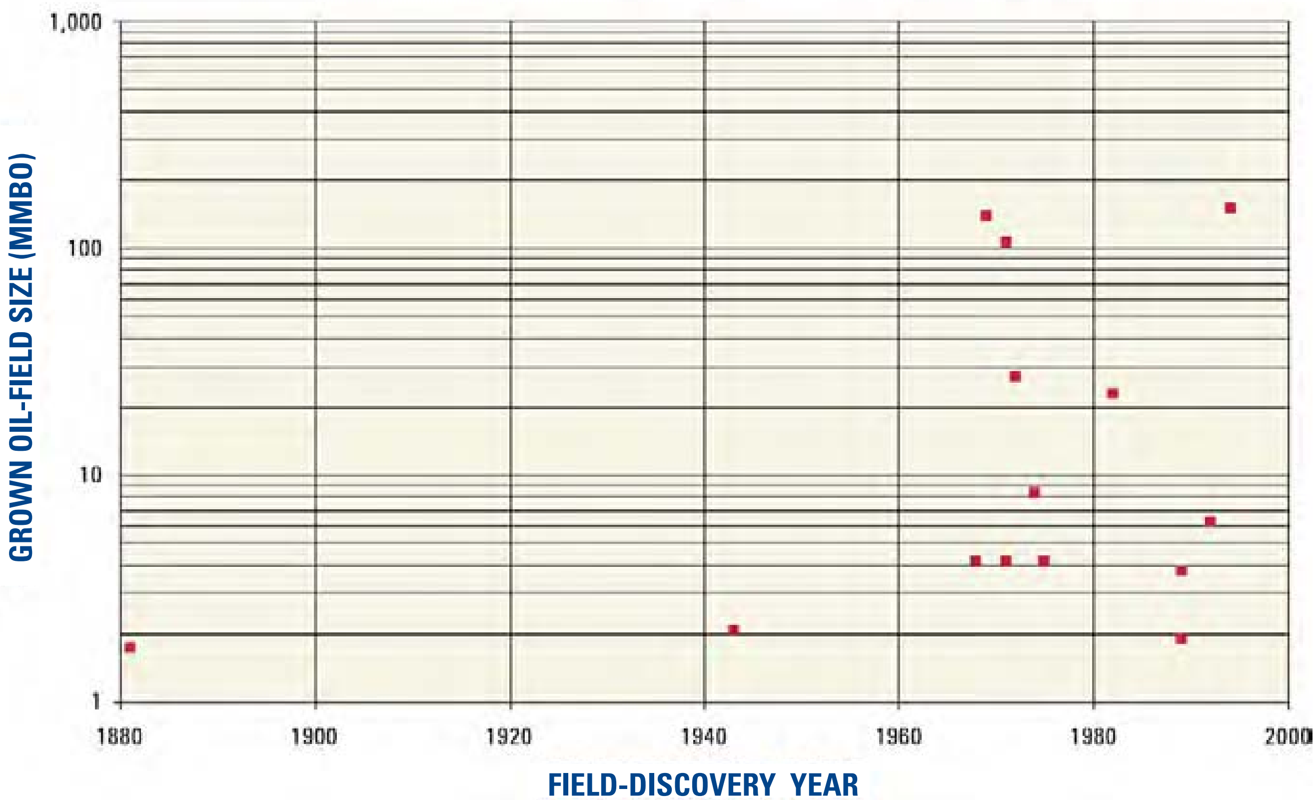

Figure 51. Oil field size compared to discovery year for the North Cuba Fold and Thrust Belt Assessment Unit. Unique number 61170101 refers to the USGS method for identifying assessment units.

For the probability distribution for numbers of undiscovered fields in the North Cuba Fold and Thrust Belt AU, the trend towards smaller fields figures into the estimated numbers in that greater numbers of smaller fields generally are discovered as exploration proceeds. This AU has 16 fields larger than minimum size, but 28 fields are listed in table 1. Some of these additional fields might be smaller than 1 MMBO, some might have been shut in and not developed, and other fields do not have production data. Given the trend towards smaller fields with time, the minimum number of undiscovered fields is estimated to be 5, the median is 60, and the maximum is estimated to be 130 (Appendix 1), which indicates that many smaller fields are postulated to remain to be discovered in this AU. There is also a small probability that an oil field of a size like the largest discovered field (Boca de Jaruco, 140 MMBO) remains to be discovered in this AU. Central to the assessment input is the concept that there might be significant potential in the deeper and offshore parts of this AU, given its exploration history and geologic complexity. Some of the deeper potential might be gas fields rather than oil fields. Since this assessment was completed, a significant heavy oil discovery was announced just offshore from known oil production (Oil and Gas Journal, 2005). Several other petroleum prospects have been identified and are undrilled (Oil and Gas Journal, 2000; 2002).

The mean estimate of gas to oil ratio (GOR) of 1,200 cubic feet of gas per barrel of oil (CFG/BO) is used in the calculation of the associated gas in undiscovered oil fields. The mean estimate of a natural gas liquids/gas ratio of 60 barrels of natural gas liquids (NGL) per million cubic feet of gas (BNGL/MMCFG) was used in the calculation of NGL volumes in undiscovered oil fields. These calculated volumes are part of the assessment of undiscovered oil and gas resources.

North Cuba Foreland Basin AU

The North Cuba Foreland Basin AU has no oil or gas fields, so the probability distributions for sizes and numbers of undiscovered oil fields and gas fields are based partly on published prospect maps derived from seismic interpretation (fig. 52) and from analog field-size distributions from geologically similar AUs. The North Cuba Foreland Basin AU was assessed for undiscovered oil and gas fields, so analog information was needed.

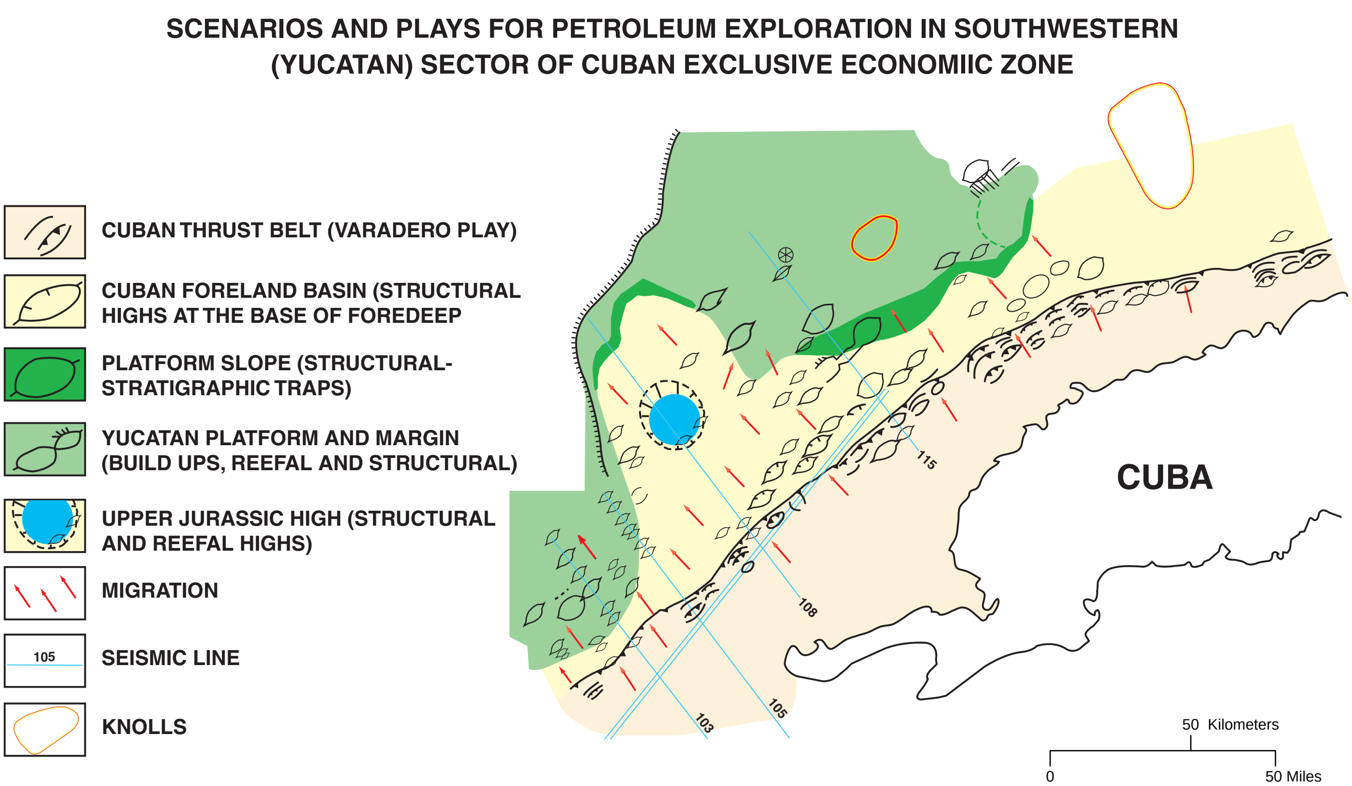

Figure 52. Oil and gas prospect map for northwestern Cuba, based on interpretation of seismic data (from Cubapetroleo, 2002).

No geologic analog exactly duplicates the geology of this AU, which basically is characterized by carbonate rocks of Jurassic and Cretaceous age overlain by clastic sediments of Paleogene age. However, in order to develop a field-size distribution, several analogs were used as a guide. For this reason, the Alberta foreland basin in western Canada, which is geologically similar, was used as a partial geologic analog. There are field-size data for several hundred oil and gas fields in this analog that can be used to evaluate the distribution of oil and gas "container sizes" that these analog fields represent. As reported in 2000, the median sizes of some 900 oil fields in 3 Alberta foreland basin AUs that have oil fields range from about 1 to 5 MMBO; within this data set are hundreds of fields with sizes less than 1 MMBO. The fields include carbonate and clastic reservoirs.

The assessment units in the Alberta foreland basin that were reviewed as partial geologic analogs include the Keg River Gas AU, Keg River Oil and Gas AU, Leduc Gas AU, Leduc Oil and Gas AU, Second White Specs-Cardium Oil and Gas AU, and the Second White Specs Gas AU (Henry, 2000). One of the major differences between these AUs and the North Cuba Foreland AU is the minimum field size used in the assessments—for the Alberta foreland basin AUs, the minimum field size was 0.5 MMBO; whereas for the North Cuba Foreland AU, the minimum was 1.0 MMBO. The inclusion of numerous oil and gas fields less than 1.0 MMBO in the Alberta data set means that the median size as reported for the Alberta fields would be less than if the minimum was 1.0 MMBO. The second difference is the scale of the assessment unit. The North Cuba Foreland Basin AU encompasses an area that is about 15 percent of the area of the Alberta Basin AUs. These differences are taken into consideration in using these Alberta Basin AUs as analogs for field sizes and numbers.

Taking into account the geologic similarities and differences between the analog Alberta foreland basin AUs and the North Cuba Foreland Basin AU, the median size of undiscovered fields in the North Cuba Basin is estimated at 10 MMBO, which is larger than the median sizes from the analogs. The rationale for the larger median field size includes: (1) the use of a larger minimum size; (2) the potential for far fewer fields in the AU; and (3) the numbers of prospects mapped in the North Cuba Foreland Basin AU by Lopez-Rivera and others (2003a)(fig. 52).

The maximum field size as requested on the assessment form (Appendix 2 at the back of the report) involves a consideration of what is termed the expectation for the "most likely largest undiscovered oil field size". In the Monte Carlo simulation of field sizes, one result is a calculated distribution of "most likely largest undiscovered oil field size", which is smaller than the maximum field size recorded on the data-input form. The "most likely largest undiscovered oil field size", using the analog data, was estimated to be a field of about 700 to 1,000 MMBO. To obtain a "most likely largest undiscovered oil field" of this size, the maximum field size on the input form would have to be about 2,500 MMBO, so this value was used as maximum field size on the data-input form (Appendix 2). Using a minimum of 1 MMBO, a median of 10 MMBO, and a maximum of 2,500 MMBO, the mean undiscovered field size is calculated to be 33 MMBO.

A parallel process is used for developing the distribution for sizes of undiscovered gas fields. A minimum gas field size of 6 BCFG was chosen to parallel the minimum oil field size of 1 MMBO. This minimum size is likewise twice the size of the minimum size from the Alberta foreland basin AUs, which was 3 BCFG. For the Alberta foreland basin AUs, the median gas field sizes among 800 fields ranges from 6 to 24 BCFG; for undiscovered gas fields in the North Cuba Foreland AU, the median gas field size is estimated at 40 BCFG. This estimate is larger than the data from the analogs and reflects: (1) the use of a higher minimum size than the analogs; (2) fewer number of potential fields in this AU compared to the Alberta analogs; and (3) the numbers of potential prospects mapped in this area by Lopez-Rivera and others (2003a). The process for estimating the maximum undiscovered gas field size is the same as for oil; an estimate of the "most likely largest undiscovered gas field size" was about 1,000 BCFG based on a largest gas fields in the analog data set (1,000-2,000 BCFG), which meant that the maximum gas field size on the input form needed to be set at about 6,000 BCFG (Appendix 2). The North Cuba Foreland Basin AU is interpreted to have a "most likely largest undiscovered gas field size" less than the largest field found in the Alberta analogs. A minimum gas field size of 6 BCFG, a median gas field size of 40 BCFG, and a maximum gas field size of 6,000 BCFG led to a calculated mean undiscovered gas field size of 144 BCFG (Appendix 2).

Based on an interpretation of seismic data (Lopez-Rivera and others, 2003a), a derivative prospect map (Cubapetroleo, 2002), and the boundaries of the AU as determined for the present study, about 24 prospects were identified within the North Cuba Foreland Basin AU (fig. 52). These prospects were interpreted from fairly widely spaced seismic lines, so only the larger structural closures might have been identified. Given that these are categorized as prospects and taking into account the geologic uncertainties of maturation, migration, and charge, the interpretation was made that about 10 of the prospects would be viable oil accumulations. However, because of the relatively sparse density of seismic lines, there is the possibility that many smaller accumulations might be present (based on a minimum size of 1 MMBO), and the potential for stratigraphic traps should not be overlooked in this AU.

For numbers of undiscovered oil fields, the estimate was a minimum of 2 accumulations, a mode of 70, and a maximum of 150 accumulations, reflecting the estimates of numbers for smaller accumulations. This distribution was scaled back considerably from the Alberta analog data, given the higher minimum size and the much smaller area of the North Cuba Foreland Basin AU compared to the Alberta analogs. For undiscovered gas fields, the estimate included a minimum of 1 accumulation, a mode of 6, and a maximum of 20 accumulations. Although modeling results showed that thermal gas is a possibility at depth in this AU, an estimate was further made that about 90 percent of the undiscovered hydrocarbon phase in this AU is oil. However, gas accumulations might be more prevalent in the deeper parts of the AU than the 10 percent estimated in these distributions. The determination of hydrocarbon phase in a frontier area such as the North Cuba Basin involves considerable uncertainty.

The modes for co-product ratios, based on data from the North Cuba Fold and Thrust Belt AU and adjusted for the increased depths and thermal maturation possible in the North Cuba Foreland Basin AU, were estimated at 2000 CFG/BO for the gas/oil ratio; 100 BNGL/MMCFG for the NGL/gas ratio in oil accumulations; and 53 barrels of liquids per million cubic feet of gas (BLIQ/MMCFG) for the liquids/gas ratio in gas fields. These ratios were used to calculate resources that are part of the assessment of undiscovered oil and gas resources. The input data for this AU are presented in Appendix 2.

North Cuba Platform Margin Carbonate AU

The North Cuba Platform Margin Carbonate AU has no known oil or gas fields, so the development of the probability distribution is based partly on a published map of prospects interpreted from seismic data (fig. 52) and on analog field-size and number distributions from geologically similar assessment units. In the southern Mexican part of the Gulf Coast basin, several assessment units from the 2000 USGS assessment (Magoon, 2000; Magoon and others, 2001) were used as guides to develop distributions for sizes and numbers of undiscovered fields. In that part of the Gulf Coast, billions of barrels of oil have been produced from carbonate reef, fore-reef, and carbonate debris-flow reservoirs that serve as a partial analog for potential reservoirs in the North Cuba Platform Margin Carbonate AU. In addition to similar reservoir rocks, the southern part of the Gulf Coast Basin contains the Jurassic Pimienta-Tamabra TPS (Magoon and others, 2001). Equivalent-age strata are a potential source rock in the North Cuba Basin and are part of the Jurassic-Cretaceous Composite TPS. Thus, the geology between these two areas is similar in many respects.

Two AUs in southern Mexico were considered as partial analogs for estimating oil field sizes and numbers for the North Cuba Platform Margin Carbonate AU, including the El Abra-like Reef and Backreef Limestone AU, and the Tamabra-like Debris Flow Breccia Limestone of the Golden Lane AU (Magoon, 2000). The minimum field size used in these analogs is identical to that used in the assessment of the North Cuba Platform Margin Carbonate AU (1 MMBO). The median oil field sizes in the reef, fore-reef, and debris-flow reservoir analogs ranged from 11-16 MMBO. The estimate for median oil field size for the undiscovered fields in the North Cuba Platform Margin Carbonate AU is 7 MMBO (Appendix 3 at the back of this report), which is about half the median size of the analog fields in the southern Gulf Coast Basin. This value was chosen primarily because: (1) there is considerable uncertainty in the migration of oil from the deeper parts of the North Cuba fold and thrust belt and foreland that could have adequately charged the platform margin reservoirs, and (2) the size of the AU area is much smaller than the AU areas in the southern Gulf Coast of Mexico.

The estimation of "most likely largest undiscovered oil field size" (200-300 MMBO) was based on the interpretation that fields as large as those in the Mexico analog—for example, a 400-MMBO field in the El Abra AU, and a 2,000 MMBO field in the Tamabra AU—probably would not be present in the North Cuba Platform Margin Carbonate AU. To arrive at the 200- to 300-MMBO value, the maximum oil field size on the input form was set at 1,000 MMBO (Appendix 3). For a distribution with a minimum size of 1 MMBO, a median of 7 MMBO, and a maximum of 1,000 MMBO, the mean undiscovered oil field size is calculated to be 25 MMBO.

The estimated numbers of undiscovered fields was based on the two analogs from the southern Gulf of Mexico Basin, where 70 to 80 fields have been discovered, and where apparently considerable potential remains in the Tamabra-type reservoirs (Magoon and others, 2001). Given the uncertainties with respect to migration and charge in the North Cuba Platform Margin Carbonate AU compared to that in the Mexico analogs, the minimum of the distribution was chosen at 1, given that few of the reservoirs might have been charged. The mode of the distribution was estimated to be 15, and the maximum of 100 fields reflects an optimistic case where oil charge was as efficient as in southern Mexico. These estimates of 1, 7, and 100 fields lead to a calculated mean number of undiscovered oil fields of 38.

The co-product ratios were estimated using data from the North Cuba Fold and Thrust Belt AU and North Cuba Foreland Basin AU and adjusted for the possibility that potentially there may be less gas in this AU. The mode of the gas/oil ratio was estimated at 1,800 CFG/BO, and the mode of the NGL/gas ratio in oil accumulations was estimated to be 100 BNGL/MMCFG. These ratios were used to calculate resources that are part of the assessment of undiscovered oil and gas resources.

Assessment Results

The quantitative assessment results for the three AUs in the Jurassic-Cretaceous Composite TPS in the North Cuba Basin are summarized in table 4. Detailed assessment results are presented in Appendices 4-6. The mean estimate for undiscovered oil resource in composite TPS is about 4.6 billion barrels of oil (BBO)—0.49 BBO in the North Cuban Fold and Thrust Belt AU; 3.2 BBO in the North Cuban Foreland Basin AU; and 0.88 BBO in the North Cuban Platform Margin Carbonate AU. Given that approximately 0.5 BBO have already been discovered in the North Cuba Fold and Thrust Belt AU, the North Cuba Foreland Basin AU is estimated to have the highest potential for undiscovered oil and gas, followed by the North Cuba Platform Margin

Carbonate AU, and the North Cuba Fold and Thrust Belt AU. However, significant geologic uncertainty is associated with these mean values as reflected by the following ranges of probabilities: (1) for the North Cuba Fold and Thrust Belt AU, the F95 (95-percent chance) estimate is 0.14 BBO, the F5 (5-percent chance) estimate is 0.9 BBO, and the mean is 0.49 BBO; (2) for the North Cuba Foreland Basin AU, the F95 estimate is 0.78 BBO, the F5 estimate is 6.38 BBO, and the mean is 3.2 BBO; and (3) for the North Cuba Platform Margin Carbonate AU, the F95 estimate is 0.13 BBO, the F5 estimate is 2.0 BBO, and the mean is 0.88 BBO. These estimates are for undiscovered resources that have the potential to exist within the boundaries of these assessment units; these estimates should not be taken as volumes of resources that will be discovered in these AUs.

Burial-history modeling of source-rock maturation in the North Cuba Basin (Magnier and others, 2004) indicated that the deeper section was in the gas generation window, so the potential for undiscovered natural gas resources was assessed, resulting in a mean estimate of 9.8 trillion cubic feet of gas (TCFG) comprised of associated gas (gas in oil fields) and of nonassociated gas (gas in gas fields; table 4). For associated gas: (1) the North Cuba Fold and Thrust Belt AU is estimated to have a mean of 0.59 TCFG, with an F95 of 0.16 TCFG and an F5 of 1.2 TCFG; (2) the North Cuba Foreland Basin AU is estimated to have a mean of 6.4 TCFG, with an F95 of 1.46 TCFG and an F5 of 13.42 TCFG; and (3) the North Cuba Platform Margin Carbonate AU is estimated to have a mean of 1.59 TCFG, with an F95 of 0.22 TCFG and an F5 of 3.8 TCFG.

For nonassociated gas, only the North Cuba Foreland Basin AU is estimated to contain gas in gas fields greater than minimum size. Undiscovered gas fields were not assessed in either of the other two AUs. There is the possibility that nonassociated gas fields exist at depth in the North Cuba Fold and Thrust Belt AU, given the high level of maturity postulated for the source rocks, and the fact that thermally mature gas has been reported from a well onshore.

Thus, of the mean total gas estimate of 9.8 TCFG in the Jurassic-Cretaceous Composite TPS (table 4), about 8.6 TCFG is estimated to be gas in oil fields (associated gas) and 1.2 TCFG is estimated to be gas in gas fields (nonassociated gas). A total mean estimate of about 0.9 BBO of natural gas liquids is estimated for the Jurassic-Cretaceous Composite TPS (table 4).

The assessment results presented here reflect interpretations of the available geologic information within the Jurassic-Cretaceous Composite TPS, and the possible insights that can be gained from analog comparisons with better known and more densely drilled areas in the southern Gulf of Mexico region. I want to strongly emphasize that considerable geologic uncertainty exists within the composite TPS in the offshore, and more geologic information would greatly aid future oil and gas assessments of the North Cuba Basin.

Conclusions

Petroleum systems of the North Cuba Basin are primarily the result of thermal maturation of Jurassic and Cretaceous source rocks caused by the formation of the North Cuba fold and thrust belt as the Cuban arc-forearc rocks of the leading edge of the Caribbean plate translated northwards during the opening of the Yucatan Basin in the Paleogene and collided with the passive carbonate margin of southern North America. The stacked thrust sheets resulted in thermal maturation of Upper Jurassic and Cretaceous source rocks and possibly Middle Jurassic rift-related source rocks. These hydrocarbon fluids may have migrated into structures in the fold and thrust belt, into structures in the foreland basin, and into stratigraphic and possibly diagenetic traps along the margins of the Yucatan and Florida carbonate platform. Potential petroleum source rocks are Jurassic and Cretaceous in age. The U.S. Geological Survey defined a Jurassic-Cretaceous Composite Total Petroleum System (TPS) and three assessment units (AU)–North Cuba Fold and Thrust Belt AU, North Cuba Foreland Basin AU, and the North Cuba Platform Margin Carbonate AU within this TPS based mainly on structure and reservoir type. There is considerable geologic uncertainty as

Table 4. Assessment results for the Jurassic-Cretaceous Composite Total Petroleum System in the North Cuba Basin.

[MMBO, million barrels of oil. BCFG, billion cubic feet of gas. MMBNGL, million barrels of natural gas liquids. Results shown are fully risked estimates. For gas fields, all liquids are included under the NGL (natural gas liquids) category. F95 represents a 95-percent chance of at least the amount tabulated. Other fractiles are defined similarly. Fractiles are additive under the assumption of perfect positive correlation. TPS is Total Petroleum System. AU is Assessment Unit. Gray shade indicates not applicable.]

	Total Petroleum Systems (TPS) and Assessment Units (AU)	Field Type	Total Undiscovered Resources											
			Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
			F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
	Jurassic-Cretaceous Composite TPS													
Conventional Oil and Gas Resources	North Cuba Fold and Thrust Belt AU	Oil	142.22	464.25	941.03	493.64	159.47	540.32	1,200.27	591.56	8.87	31.53	75.66	35.47
		Gas					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	North Cuba Foreland Basin AU	Oil	781.13	3,014.17	6,374.50	3,218.85	1,464.93	5,863.30	13,421.82	6,451.18	137.43	569.20	1,406.66	644.74
		Gas					141.29	862.16	3,418.47	1,190.46	7.09	44.07	184.63	63.13
	North Cuba Platform Margin Carbonate AU	Oil	131.66	759.73	2,036.87	883.13	221.42	1,330.19	3,841.07	1,588.79	20.71	129.67	399.05	158.90
		Gas					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Total Undiscovered Oil and Gas Resources		**1,055.01**	**4,238.15**	**9,352.40**	**4,595.62**	**1,987.11**	**8,595.97**	**21,881.63**	**9,821.99**	**174.10**	**774.47**	**2,066.00**	**902.24**

to the extent of petroleum migration that might have occurred within this TPS to form potential petroleum accumulations, and petroleum migration is interpreted potentially to be a limiting factor in the formation of oil and gas accumulations in the North Cuba Foreland Basin AU and the North Cuba Platform Margin Carbonate AU. Reservoir quality might be a limiting factor in the North Cuba Foreland Basin AU. Taking geologic uncertainty into account, especially in the offshore area, the mean volume of undiscovered oil in the Jurassic-Cretaceous Composite TPS of the North Cuba Basin is estimated to be about 4.6 billion barrels of oil (BBO), and the mean ranges from an F95 probability of 1 BBO to an F5 probability of 9 BBO. The mean volume of undiscovered gas is about 9.8 trillion cubic feet of gas (TCFG), and of this total, 8.6 TCFG is associated with oil fields, and about 1.2 TCFG is estimated to be gas in nonassociated gas fields in the North Cuba Foreland Basin AU.

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Appendix 1. Assessment input data for North Cuba Fold and Thrust Belt AU.

SEVENTH APPROXIMATION
NEW MILLENNIUM WORLD PETROLEUM ASSESSMENT
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS

Date:…………………………..	12/15/1999		
Assessment Geologist:……..	C.J. Schenk		
Region:………………………..	Central and South America	Number:	6
Province:………………………	Greater Antilles Deformed Belt	Number:	6117
Priority or Boutique.…………	Boutique		
Total Petroleum System:……	Upper Jurassic-Neocomian	Number:	611701
Assessment Unit:……………	North Cuba Fold and Thrust Belt	Number:	61170101
* Notes from Assessor	Lower 48 growth factor.		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall):… Oil

What is the minimum field size?………. 1 mmboe grown (≥1mmboe)
(the smallest field that has potential to be added to reserves in the next 30 years)

Number of discovered fields exceeding minimum size:………… Oil: 16 Gas: 0
Established (>13 fields) X Frontier (1-13 fields) ____ Hypothetical (no fields) ____

Median size (grown) of discovered oil fields (mmboe):
1st 3rd 4.2 2nd 3rd 8.3 3rd 3rd 6.2
Median size (grown) of discovered gas fields (bcfg):
1st 3rd ____ 2nd 3rd ____ 3rd 3rd ____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered field ≥ minimum size………………	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered field ≥ minimum size……	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered field ≥ minimum size	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3):……...……....…. 1.0

4. **ACCESSIBILITY:** Adequate location to allow exploration for an undiscovered field ≥ minimum size………………………………………………...………………..……..………… 1.0

UNDISCOVERED FIELDS

Number of Undiscovered Fields: How many undiscovered fields exist that are ≥ minimum size?:
(uncertainty of fixed but unknown values)

Oil fields:…………………………………min. no. (>0)	5	median no.	60	max no.	130
Gas fields:……………………………….min. no. (>0)		median no.		max no.	

Size of Undiscovered Fields: What are the anticipated sizes (**grown**) of the above fields?:
(variations in the sizes of undiscovered fields)

Oil in oil fields (mmbo)………………..……min. size	1	median size	3	max. size	300
Gas in gas fields (bcfg):……………………min. size		median size		max. size	

Appendix 1. Assessment input data for North Cuba Fold and Thrust Belt AU.—Continued

Assessment Unit (name, no.)
North Cuba Fold and Thrust Belt, 61170101

AVERAGE RATIOS FOR UNDISCOVERED FIELDS, TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Fields:	minimum	median	maximum
Gas/oil ratio (cfg/bo)	600	1200	1800
NGL/gas ratio (bngl/mmcfg)	30	60	90

Gas fields:	minimum	median	maximum
Liquids/gas ratio (bngl/mmcfg)			
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED FIELDS
(variations in the properties of undiscovered fields)

Oil Fields:	minimum	median	maximum
API gravity (degrees)	15	25	40
Sulfur content of oil (%)	0.5	2.5	5
Drilling Depth (m)	500	2000	4000
Depth (m) of water (if applicable)	0	200	500

Gas Fields:	minimum	median	maximum
Inert gas content (%)			
CO_2 content (%)			
Hydrogen-sulfide content (%)			
Drilling Depth (m)			
Depth (m) of water (if applicable)			

ALLOCATION OF UNDISCOVERED RESOURCES IN THE ASSESSMENT UNIT
TO COUNTRIES OR OTHER LAND PARCELS (uncertainty of fixed but unknown values)

1. Cuba represents 100 areal % of the total assessment unit

Oil in Oil Fields:	minimum	median	maximum
Richness factor (unitless multiplier):			
Volume % in parcel (areal % x richness factor):		100	
Portion of volume % that is offshore (0-100%)		80	

Gas in Gas Fields:	minimum	median	maximum
Richness factor (unitless multiplier):			
Volume % in parcel (areal % x richness factor):			
Portion of volume % that is offshore (0-100%)			

Appendix 2. Assessment input data for North Cuba Foreland Basin AU.

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

IDENTIFICATION INFORMATION

Assessment Geologist:	C.J. Schenk	Date:	10/20/2004
Region:	Central and South America	Number:	6
Province:	Greater Antilles Deformed Belt	Number:	6117
Total Petroleum System:	Jurassic-Cretaceous Composite	Number:	611701
Assessment Unit:	North Cuba Foreland Basin	Number:	61170102
Based on Data as of:			
Notes from Assessor:	Possible oil discovery by Repsol		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall): Oil

What is the minimum accumulation size? 1 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 0 Gas: 0
Established (>13 accums.) _____ Frontier (1-13 accums.) _____ Hypothetical (no accums X

Median size (grown) of discovered oil accumulations (mmbo):
1st 3rd _____ 2nd 3rd _____ 3rd 3rd _____
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd _____ 2nd 3rd _____ 3rd 3rd _____

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum siz	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

	minimum (>0)	mode	maximum
Oil Accumulations:	2	70	150
Gas Accumulations:	1	6	20

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

	minimum	median	maximum
Oil in Oil Accumulations (mmbo):	1	10	2500
Gas in Gas Accumulations (bcfg):	6	40	6000

Appendix 2. Assessment input data for North Cuba Foreland Basin AU.—Continued

Assessment Unit (name, no.)
North Cuba Foreland Basin, 61170102

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	1000	2000	3000
NGL/gas ratio (bngl/mmcfg)	50	100	150

Gas Accumulations:	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)	27	53	79
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	mode	maximum
API gravity (degrees)	20	32	45
Sulfur content of oil (%)	0.5	2	10
Depth (m) of water (if applicable)	200	700	2500

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	500		2000		5000

Gas Accumulations:	minimum	mode	maximum
Inert gas content (%)	0	0	15
CO_2 content (%)	0	2	55
Hydrogen-sulfide content (%)	0	0	5
Depth (m) of water (if applicable)	200	700	2500

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	1000		2500		5000

Appendix 2. Assessment input data for North Cuba Foreland Basin AU.—Continued

Assessment Unit (name, no.)
North Cuba Foreland Basin, 61170102

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO STATES
Surface Allocations (uncertainty of a fixed value)

1. Cuba represents 100 area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity		100	
Gas in Gas Accumulations:			
Volume % in entity		100	

2. Offshore represents 100 area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity		100	
Gas in Gas Accumulations:			
Volume % in entity		100	

3. ______ represents ______ area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity			
Gas in Gas Accumulations:			
Volume % in entity			

4. ______ represents ______ area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity			
Gas in Gas Accumulations:			
Volume % in entity			

5. ______ represents ______ area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity			
Gas in Gas Accumulations:			
Volume % in entity			

6. ______ represents ______ area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity			
Gas in Gas Accumulations:			
Volume % in entity			

Appendix 3. Assessment input data for North Cuba Platform Margin Carbonate AU.

SEVENTH APPROXIMATION
DATA FORM FOR CONVENTIONAL ASSESSMENT UNITS (Version 6, 9 April 2003)

IDENTIFICATION INFORMATION

Assessment Geologist:	C.J. Schenk	Date:	10/20/2004
Region:	Central and South America	Number:	6
Province:	Greater Antilles Deformed Belt	Number:	6117
Total Petroleum System:	Jurassic-Cretaceous Composite	Number:	611701
Assessment Unit:	North Cuba Platform Margin Carbonate	Number:	61170103
Based on Data as of:			
Notes from Assessor:	Tamaulipas-Like Basinal Limestone and Tertiary Strata Without Underlying Evaporites (53050105) as analog.		

CHARACTERISTICS OF ASSESSMENT UNIT

Oil (<20,000 cfg/bo overall) **or** Gas (≥20,000 cfg/bo overall): Oil

What is the minimum accumulation size? 1 mmboe grown
(the smallest accumulation that has potential to be added to reserves)

No. of discovered accumulations exceeding minimum size: Oil: 0 Gas: 0
Established (>13 accums.) ______ Frontier (1-13 accums.) ______ Hypothetical (no accums X

Median size (grown) of discovered oil accumulations (mmbo):
1st 3rd ______ 2nd 3rd ______ 3rd 3rd ______
Median size (grown) of discovered gas accumulations (bcfg):
1st 3rd ______ 2nd 3rd ______ 3rd 3rd ______

Assessment-Unit Probabilities:

Attribute	Probability of occurrence (0-1.0)
1. **CHARGE:** Adequate petroleum charge for an undiscovered accum. ≥ minimum size:	1.0
2. **ROCKS:** Adequate reservoirs, traps, and seals for an undiscovered accum. ≥ minimum size:	1.0
3. **TIMING OF GEOLOGIC EVENTS:** Favorable timing for an undiscovered accum. ≥ minimum siz	1.0

Assessment-Unit GEOLOGIC Probability (Product of 1, 2, and 3): 1.0

UNDISCOVERED ACCUMULATIONS

No. of Undiscovered Accumulations: How many undiscovered accums. exist that are ≥ min. size?:
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum (>0)	1	mode	15	maximum	100
Gas Accumulations:	minimum (>0)		mode		maximum	

Sizes of Undiscovered Accumulations: What are the sizes (**grown**) of the above accums?:
(variations in the sizes of undiscovered accumulations)

Oil in Oil Accumulations (mmbo):	minimum	1	median	7	maximum	1000
Gas in Gas Accumulations (bcfg):	minimum		median		maximum	

Appendix 3. Assessment input data for North Cuba Platform Margin Carbonate AU.—Continued

Assessment Unit (name, no.)
North Cuba Platform Margin Carbonate, 61170103

AVERAGE RATIOS FOR UNDISCOVERED ACCUMS., TO ASSESS COPRODUCTS
(uncertainty of fixed but unknown values)

Oil Accumulations:	minimum	mode	maximum
Gas/oil ratio (cfg/bo)	900	1800	2700
NGL/gas ratio (bngl/mmcfg)	50	100	150

Gas Accumulations:	minimum	mode	maximum
Liquids/gas ratio (bliq/mmcfg)			
Oil/gas ratio (bo/mmcfg)			

SELECTED ANCILLARY DATA FOR UNDISCOVERED ACCUMULATIONS
(variations in the properties of undiscovered accumulations)

Oil Accumulations:	minimum	mode	maximum
API gravity (degrees)	20	32	45
Sulfur content of oil (%)	0.5	2	10
Depth (m) of water (if applicable)	100	500	1500

	minimum	F75	mode	F25	maximum
Drilling Depth (m)	500		2000		4500

Gas Accumulations:	minimum	mode	maximum
Inert gas content (%)			
CO_2 content (%)			
Hydrogen-sulfide content (%)			
Depth (m) of water (if applicable)			

	minimum	F75	mode	F25	maximum
Drilling Depth (m)					

Appendix 3. Assessment input data for North Cuba Platform Margin Carbonate AU.—Continued

Assessment Unit (name, no.)
North Cuba Platform Margin Carbonate, 61170103

ALLOCATIONS OF POTENTIAL ADDITIONS TO RESERVES TO STATES
Surface Allocations (uncertainty of a fixed value)

1. Cuba represents 96 area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity		100	
Gas in Gas Accumulations:			
Volume % in entity			

2. Mexico represents 4 area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity		0	
Gas in Gas Accumulations:			
Volume % in entity			

3. Offshore represents 100 area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity		100	
Gas in Gas Accumulations:			
Volume % in entity			

4. _____ represents _____ area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity			
Gas in Gas Accumulations:			
Volume % in entity			

5. _____ represents _____ area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity			
Gas in Gas Accumulations:			
Volume % in entity			

6. _____ represents _____ area % of the AU

	minimum	mode	maximum
Oil in Oil Accumulations:			
Volume % in entity			
Gas in Gas Accumulations:			
Volume % in entity			

Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.

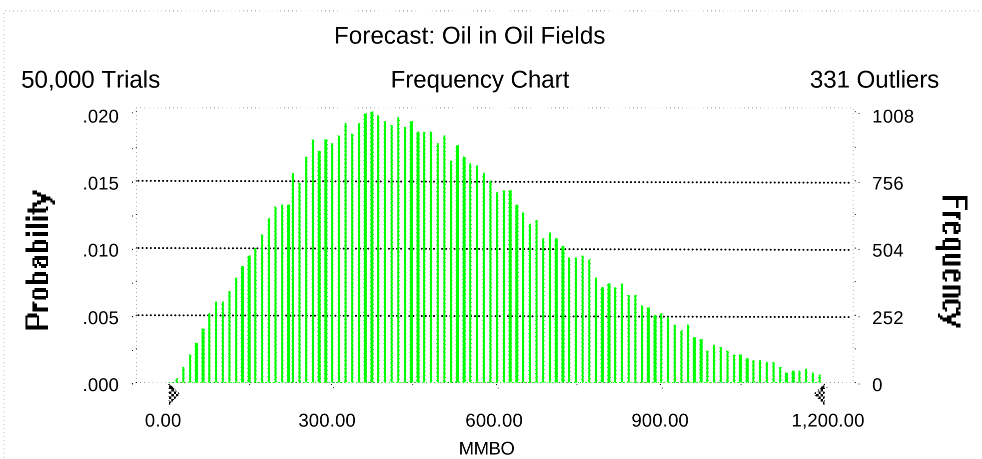
61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Forecast: Oil in Oil Fields

Summary:

Display range is from 0.00 to 1,200.00 MMBO
Entire range is from 12.95 to 1,745.94 MMBO
After 50,000 trials, the standard error of the mean is 1.10

Statistics:	Value
Trials	50000
Mean	493.64
Median	464.25
Mode	---
Standard Deviation	245.18
Variance	60,112.67
Skewness	0.60
Kurtosis	3.14
Coefficient of Variability	0.50
Range Minimum	12.95
Range Maximum	1,745.94
Range Width	1,732.98
Mean Standard Error	1.10



Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Forecast: Oil in Oil Fields (cont'd)

Percentiles:

Percentile	MMBO
100%	12.95
95%	142.22
90%	197.14
85%	239.84
80%	275.78
75%	309.69
70%	341.70
65%	372.38
60%	401.85
55%	433.21
50%	464.25
45%	496.98
40%	530.68
35%	566.30
30%	605.35
25%	647.85
20%	698.76
15%	757.42
10%	832.22
5%	941.03
0%	1,745.94

End of Forecast

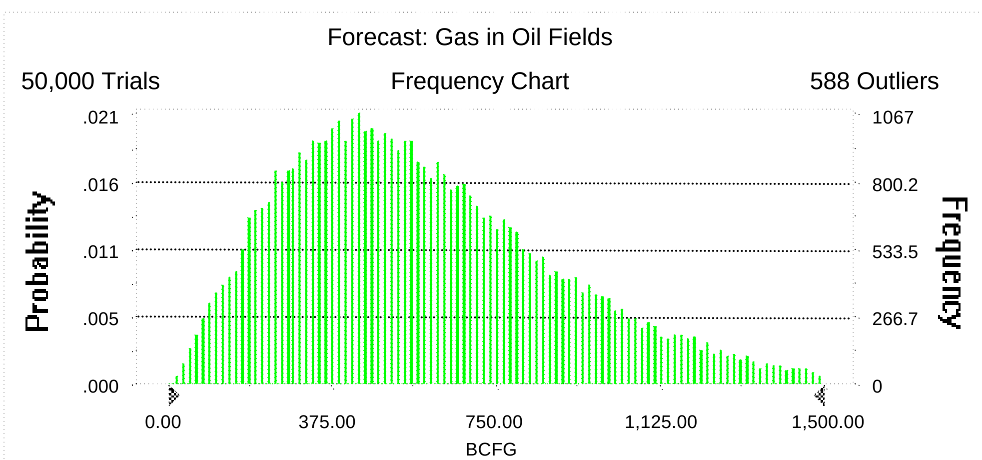
Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Forecast: Gas in Oil Fields

Summary:
Display range is from 0.00 to 1,500.00 BCFG
Entire range is from 11.41 to 2,471.58 BCFG
After 50,000 trials, the standard error of the mean is 1.44

Statistics:	Value
Trials	50000
Mean	591.56
Median	540.32
Mode	---
Standard Deviation	322.65
Variance	104,104.39
Skewness	0.86
Kurtosis	3.82
Coefficient of Variability	0.55
Range Minimum	11.41
Range Maximum	2,471.58
Range Width	2,460.17
Mean Standard Error	1.44



Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Forecast: Gas in Oil Fields (cont'd)

Percentiles:

Percentile	BCFG
100%	11.41
95%	159.47
90%	219.95
85%	267.78
80%	311.46
75%	351.53
70%	389.96
65%	427.00
60%	463.11
55%	501.36
50%	540.32
45%	580.22
40%	623.85
35%	670.71
30%	720.57
25%	778.67
20%	845.15
15%	929.01
10%	1,033.20
5%	1,200.27
0%	2,471.58

End of Forecast

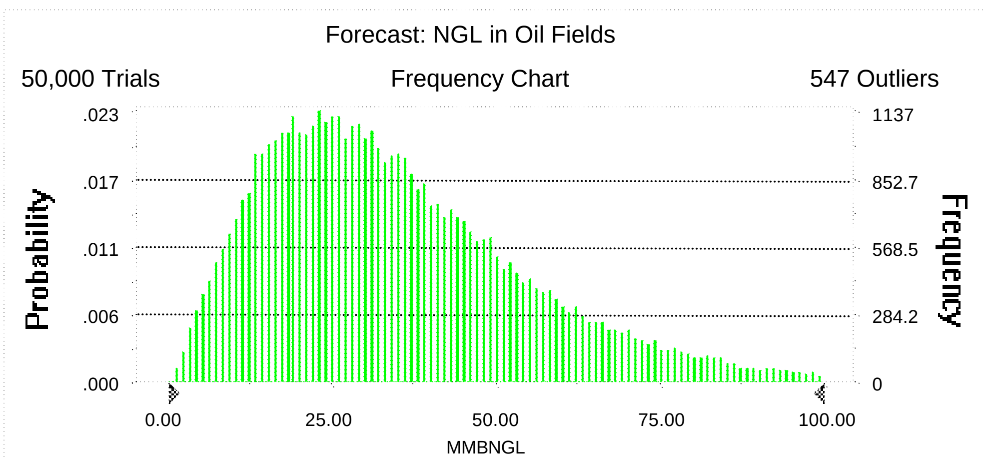
Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Forecast: NGL in Oil Fields

Summary:
Display range is from 0.00 to 100.00 MMBNGL
Entire range is from 0.68 to 188.91 MMBNGL
After 50,000 trials, the standard error of the mean is 0.09

Statistics:	Value
Trials	50000
Mean	35.47
Median	31.53
Mode	---
Standard Deviation	21.04
Variance	442.78
Skewness	1.14
Kurtosis	4.87
Coefficient of Variability	0.59
Range Minimum	0.68
Range Maximum	188.91
Range Width	188.24
Mean Standard Error	0.09



Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Forecast: NGL in Oil Fields (cont'd)

Percentiles:

Percentile	MMBNGL
100%	0.68
95%	8.87
90%	12.46
85%	15.15
80%	17.58
75%	19.90
70%	22.27
65%	24.54
60%	26.78
55%	29.13
50%	31.53
45%	34.09
40%	36.71
35%	39.67
30%	43.04
25%	46.66
20%	50.91
15%	56.34
10%	63.75
5%	75.66
0%	188.91

End of Forecast

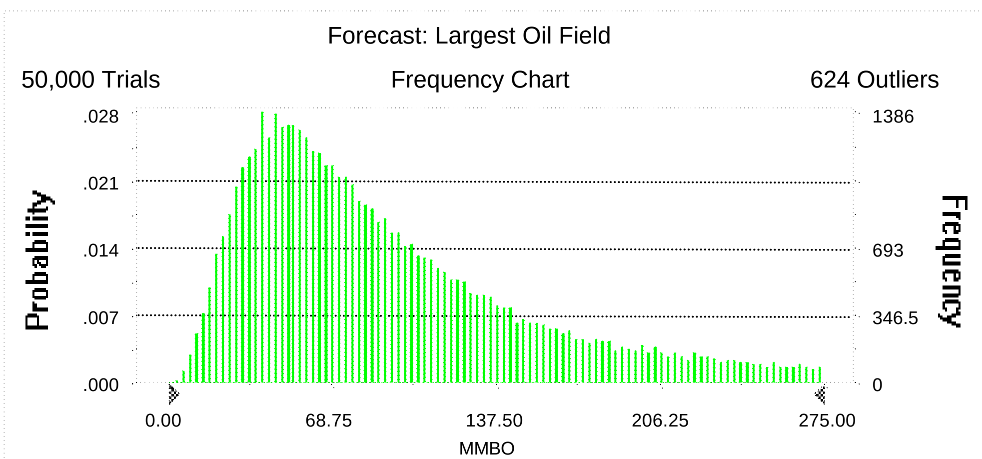
Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Forecast: Largest Oil Field

Summary:
Display range is from 0.00 to 275.00 MMBO
Entire range is from 2.90 to 299.89 MMBO
After 50,000 trials, the standard error of the mean is 0.27

Statistics:	Value
Trials	50000
Mean	92.64
Median	76.08
Mode	---
Standard Deviation	60.83
Variance	3,699.80
Skewness	1.19
Kurtosis	3.98
Coefficient of Variability	0.66
Range Minimum	2.90
Range Maximum	299.89
Range Width	296.99
Mean Standard Error	0.27



Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Forecast: Largest Oil Field (cont'd)

Percentiles:

Percentile	MMBO
100%	2.90
95%	23.78
90%	31.17
85%	37.16
80%	42.40
75%	47.54
70%	52.72
65%	58.02
60%	63.59
55%	69.60
50%	76.08
45%	83.05
40%	90.93
35%	99.60
30%	109.84
25%	121.79
20%	136.16
15%	155.50
10%	182.46
5%	223.86
0%	299.89

End of Forecast

Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

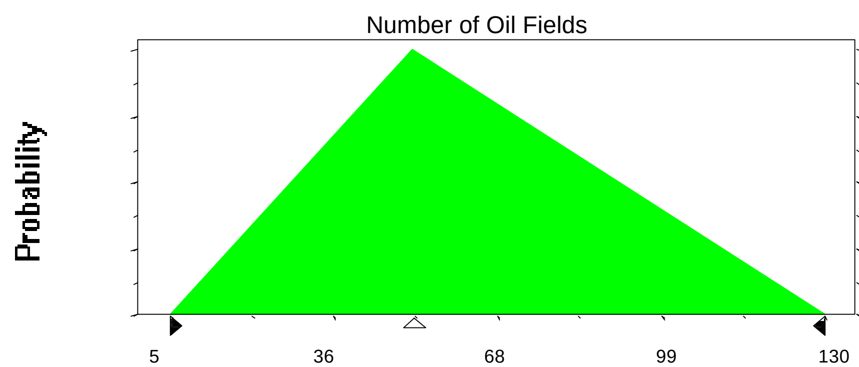
61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Assumptions

Assumption: Number of Oil Fields

Triangular distribution with parameters:	
Minimum	5
Likeliest	52
Maximum	130

Selected range is from 5 to 130
Mean value in simulation was 62



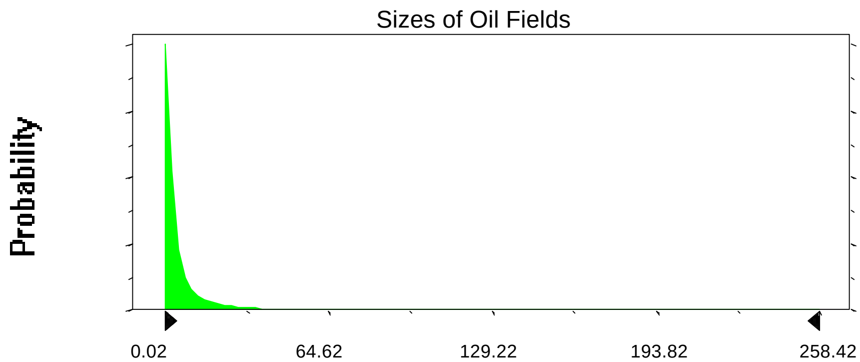
Assumption: Sizes of Oil Fields

		Shifted parameters
Lognormal distribution with parameters:		
Mean	7.43	8.43
Standard Deviation	26.62	26.62
Selected range is from 0.00 to 299.00		1.00 to 300.00
Mean value in simulation was 6.90		7.9

Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Assumption: Sizes of Oil Fields (cont'd)

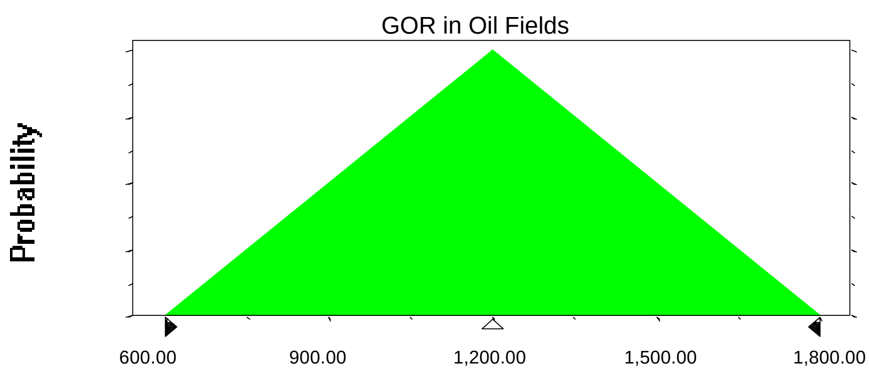


Assumption: GOR in Oil Fields

Triangular distribution with parameters:

Minimum	600.00
Likeliest	1,200.00
Maximum	1,800.00

Selected range is from 600.00 to 1,800.00
Mean value in simulation was 1,198.52



Appendix 4. Detailed assessment results for North Cuba Fold and Thrust Belt AU.—Continued

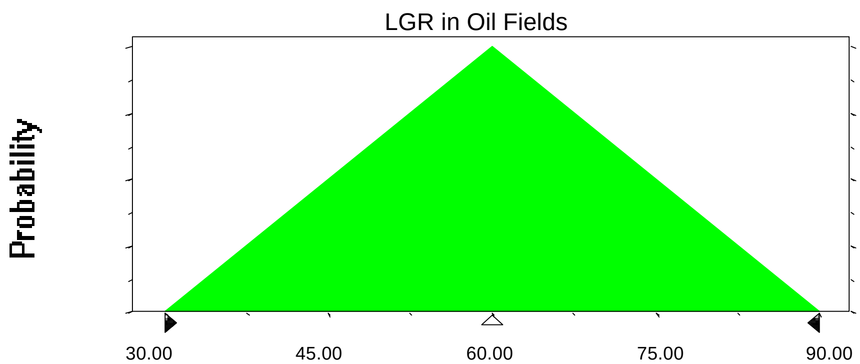
61170101
North Cuba Fold and Thrust Belt
Monte Carlo Results

Assumption: LGR in Oil Fields

Triangular distribution with parameters:

Minimum	30.00
Likeliest	60.00
Maximum	90.00

Selected range is from 30.00 to 90.00
Mean value in simulation was 59.97



End of Assumptions

Simulation started on 1/4/00 at 15:39:38
Simulation stopped on 1/4/00 at 16:11:48

Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.

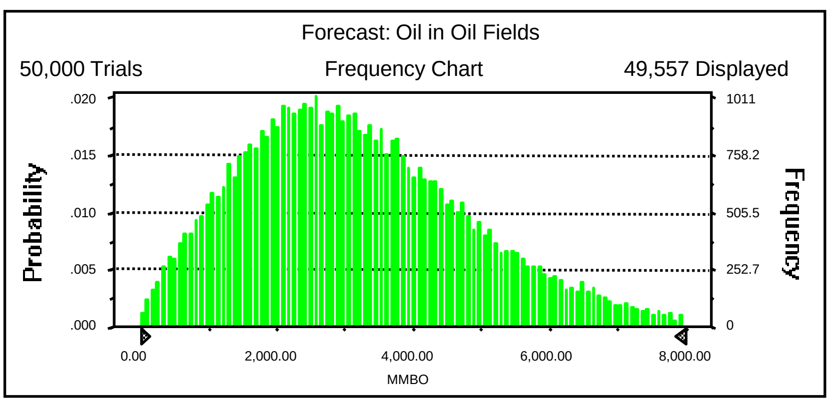
61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Oil in Oil Fields

Summary:

Display range is from 0.00 to 8,000.00 MMBO
Entire range is from 8.60 to 12,491.39 MMBO
After 50,000 trials, the standard error of the mean is 7.62

Statistics:	Value
Trials	50000
Mean	3,218.85
Median	3,014.17
Mode	---
Standard Deviation	1,704.92
Variance	2,906,749.56
Skewness	0.67
Kurtosis	3.42
Coefficient of Variability	0.53
Range Minimum	8.60
Range Maximum	12,491.39
Range Width	12,482.79
Mean Standard Error	7.62



Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Oil in Oil Fields (cont'd)

Percentiles:

Percentile	MMBO
100%	8.60
95%	781.13
90%	1,167.44
85%	1,466.95
80%	1,724.69
75%	1,959.11
70%	2,174.57
65%	2,386.67
60%	2,588.79
55%	2,802.75
50%	3,014.17
45%	3,233.52
40%	3,464.27
35%	3,707.11
30%	3,964.11
25%	4,264.83
20%	4,596.92
15%	5,000.72
10%	5,544.16
5%	6,374.50
0%	12,491.39

End of Forecast

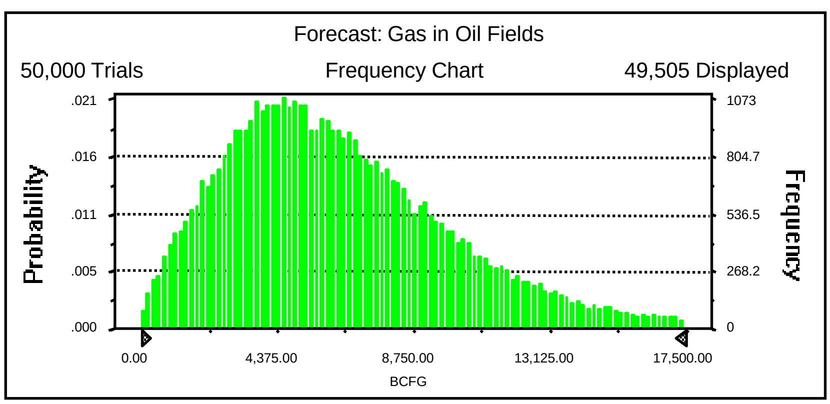
Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Gas in Oil Fields

Summary:
Display range is from 0.00 to 17,500.00 BCFG
Entire range is from 7.99 to 34,148.60 BCFG
After 50,000 trials, the standard error of the mean is 16.64

Statistics:	Value
Trials	50000
Mean	6,451.18
Median	5,863.30
Mode	---
Standard Deviation	3,721.79
Variance	13,851,698.87
Skewness	0.95
Kurtosis	4.28
Coefficient of Variability	0.58
Range Minimum	7.99
Range Maximum	34,148.60
Range Width	34,140.61
Mean Standard Error	16.64



Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Gas in Oil Fields (cont'd)

Percentiles:

Percentile	BCFG
100%	7.99
95%	1,464.93
90%	2,195.09
85%	2,783.49
80%	3,266.81
75%	3,725.03
70%	4,144.03
65%	4,566.25
60%	4,979.84
55%	5,399.35
50%	5,863.30
45%	6,325.12
40%	6,803.70
35%	7,329.20
30%	7,910.10
25%	8,539.31
20%	9,301.17
15%	10,213.17
10%	11,460.17
5%	13,421.82
0%	34,148.60

End of Forecast

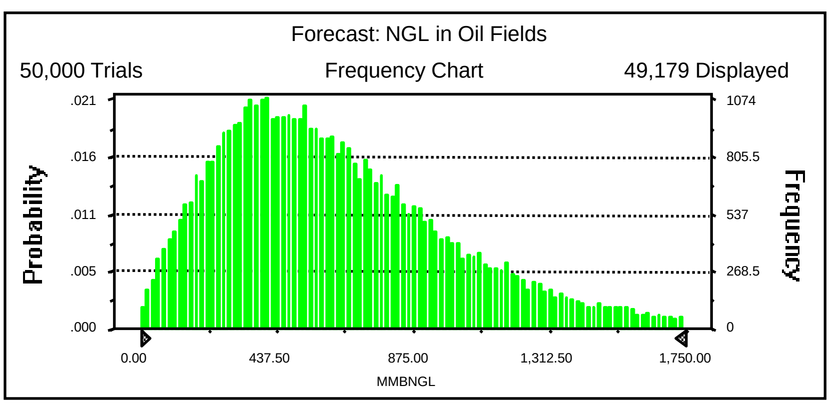
Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: NGL in Oil Fields

Summary:
Display range is from 0.00 to 1,750.00 MMBNGL
Entire range is from 0.97 to 3,942.78 MMBNGL
After 50,000 trials, the standard error of the mean is 1.79

Statistics:	Value
Trials	50000
Mean	644.74
Median	569.20
Mode	---
Standard Deviation	401.04
Variance	160,834.30
Skewness	1.18
Kurtosis	5.23
Coefficient of Variability	0.62
Range Minimum	0.97
Range Maximum	3,942.78
Range Width	3,941.81
Mean Standard Error	1.79



Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: NGL in Oil Fields (cont'd)

Percentiles:

Percentile	MMBNGL
100%	0.97
95%	137.43
90%	205.22
85%	261.02
80%	308.29
75%	352.04
70%	393.82
65%	436.21
60%	480.78
55%	524.45
50%	569.20
45%	617.83
40%	668.63
35%	725.60
30%	785.87
25%	855.64
20%	937.34
15%	1,041.05
10%	1,182.35
5%	1,406.66
0%	3,942.78

End of Forecast

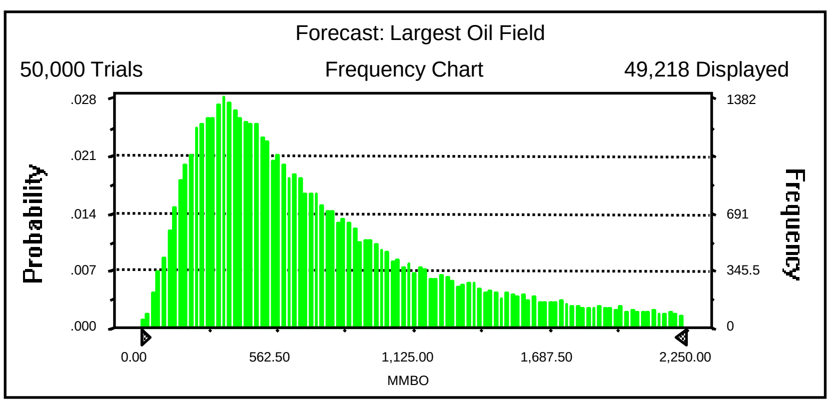
Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Largest Oil Field

Summary:
Display range is from 0.00 to 2,250.00 MMBO
Entire range is from 4.56 to 2,499.34 MMBO
After 50,000 trials, the standard error of the mean is 2.33

Statistics:	Value
Trials	50000
Mean	736.50
Median	586.69
Mode	---
Standard Deviation	520.60
Variance	271,028.07
Skewness	1.21
Kurtosis	3.99
Coefficient of Variability	0.71
Range Minimum	4.56
Range Maximum	2,499.34
Range Width	2,494.77
Mean Standard Error	2.33



Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Largest Oil Field (cont'd)

Percentiles:

Percentile	MMBO
100%	4.56
95%	159.93
90%	218.04
85%	264.94
80%	309.99
75%	352.30
70%	393.80
65%	438.42
60%	483.80
55%	532.45
50%	586.69
45%	647.28
40%	713.62
35%	787.86
30%	873.61
25%	977.33
20%	1,109.51
15%	1,280.74
10%	1,518.86
5%	1,872.20
0%	2,499.34

End of Forecast

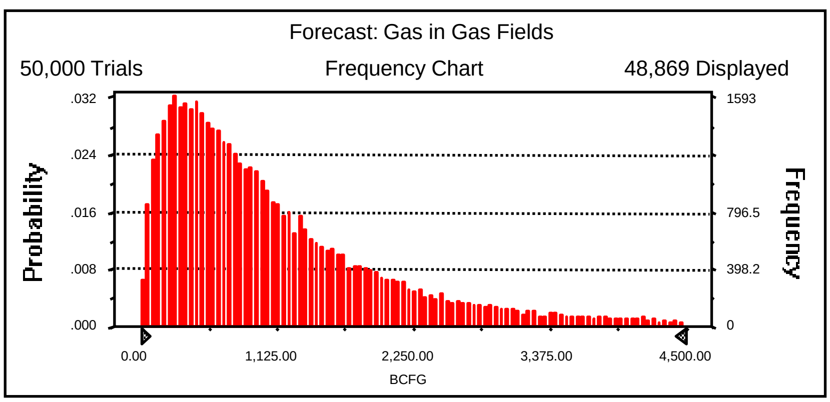
Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Gas in Gas Fields

Summary:
Display range is from 0.00 to 4,500.00 BCFG
Entire range is from 6.29 to 11,733.00 BCFG
After 50,000 trials, the standard error of the mean is 5.00

Statistics:	Value
Trials	50000
Mean	1,190.46
Median	862.16
Mode	---
Standard Deviation	1,117.77
Variance	1,249,411.60
Skewness	2.22
Kurtosis	10.05
Coefficient of Variability	0.94
Range Minimum	6.29
Range Maximum	11,733.00
Range Width	11,726.71
Mean Standard Error	5.00



Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Gas in Gas Fields (cont'd)

Percentiles:

Percentile	BCFG
100%	6.29
95%	141.29
90%	222.88
85%	294.74
80%	367.99
75%	441.05
70%	514.71
65%	593.17
60%	676.05
55%	764.99
50%	862.16
45%	964.72
40%	1,076.24
35%	1,212.87
30%	1,368.67
25%	1,558.22
20%	1,791.63
15%	2,092.87
10%	2,550.18
5%	3,418.47
0%	11,733.00

End of Forecast

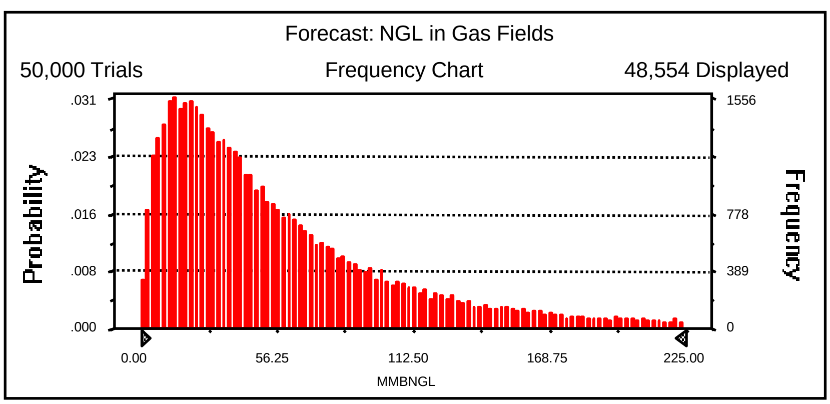
Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: NGL in Gas Fields

Summary:
Display range is from 0.00 to 225.00 MMBNGL
Entire range is from 0.33 to 772.85 MMBNGL
After 50,000 trials, the standard error of the mean is 0.28

Statistics:	Value
Trials	50000
Mean	63.13
Median	44.07
Mode	---
Standard Deviation	62.25
Variance	3,875.49
Skewness	2.48
Kurtosis	12.39
Coefficient of Variability	0.99
Range Minimum	0.33
Range Maximum	772.85
Range Width	772.52
Mean Standard Error	0.28



Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: NGL in Gas Fields (cont'd)

Percentiles:

Percentile	MMBNGL
100%	0.33
95%	7.09
90%	11.30
85%	14.96
80%	18.67
75%	22.29
70%	26.13
65%	30.21
60%	34.59
55%	39.12
50%	44.07
45%	49.75
40%	56.09
35%	63.33
30%	71.60
25%	81.73
20%	94.81
15%	111.73
10%	137.33
5%	184.63
0%	772.85

End of Forecast

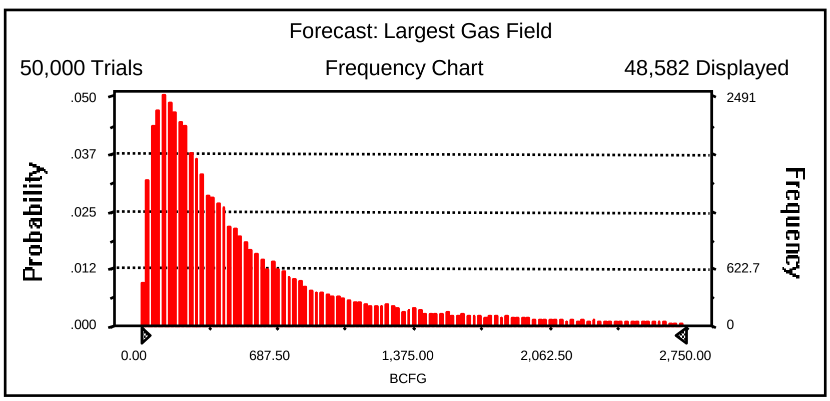
Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Largest Gas Field

Summary:
Display range is from 0.00 to 2,750.00 BCFG
Entire range is from 6.29 to 5,987.67 BCFG
After 50,000 trials, the standard error of the mean is 3.41

Statistics:	Value
Trials	50000
Mean	617.19
Median	359.40
Mode	---
Standard Deviation	761.43
Variance	579,770.50
Skewness	3.04
Kurtosis	14.88
Coefficient of Variability	1.23
Range Minimum	6.29
Range Maximum	5,987.67
Range Width	5,981.38
Mean Standard Error	3.41



Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Forecast: Largest Gas Field (cont'd)

Percentiles:

Percentile	BCFG
100%	6.29
95%	61.29
90%	91.99
85%	120.53
80%	148.71
75%	177.72
70%	207.68
65%	238.85
60%	274.63
55%	313.18
50%	359.40
45%	410.03
40%	468.52
35%	537.95
30%	624.00
25%	730.10
20%	874.70
15%	1,090.80
10%	1,426.76
5%	2,090.76
0%	5,987.67

End of Forecast

Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

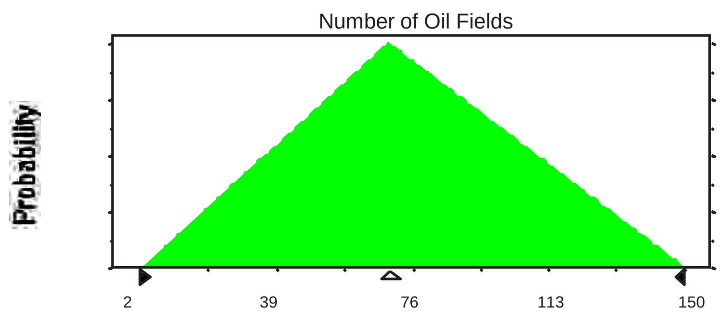
Assumptions

Assumption: Number of Oil Fields

Triangular distribution with parameters:

Minimum	2
Likeliest	70
Maximum	150

Selected range is from 2 to 150



Assumption: Sizes of Oil Fields

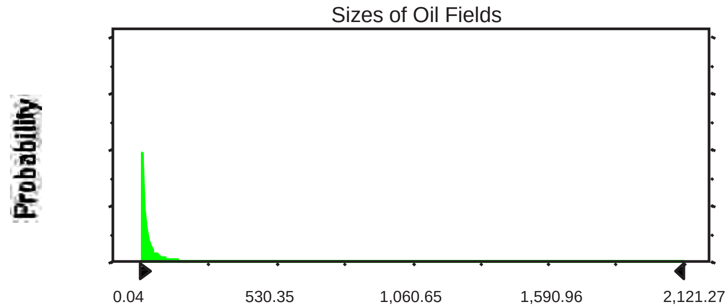
Lognormal distribution with parameters:		Shifted parameters
Mean	47.23	47.73
Standard Deviation	243.28	243.28

Selected range is from 0.00 to 2,499.00 0.50 to 2,499.50

Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

Assumption: Sizes of Oil Fields (cont'd)

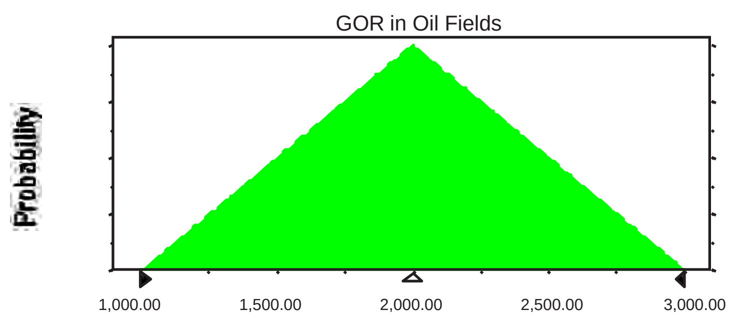


Assumption: GOR in Oil Fields

Triangular distribution with parameters:

Minimum	1,000.00
Likeliest	2,000.00
Maximum	3,000.00

Selected range is from 1,000.00 to 3,000.00



Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

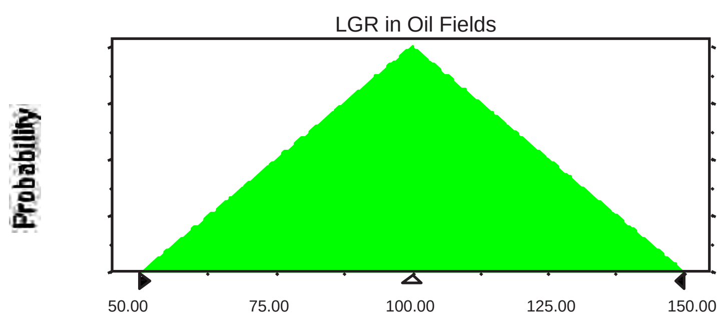
61170102
North Cuba Foreland Basin
Monte Carlo Results

Assumption: LGR in Oil Fields

Triangular distribution with parameters:

Minimum	50.00
Likeliest	100.00
Maximum	150.00

Selected range is from 50.00 to 150.00



Assumption: Number of Gas Fields

Triangular distribution with parameters:

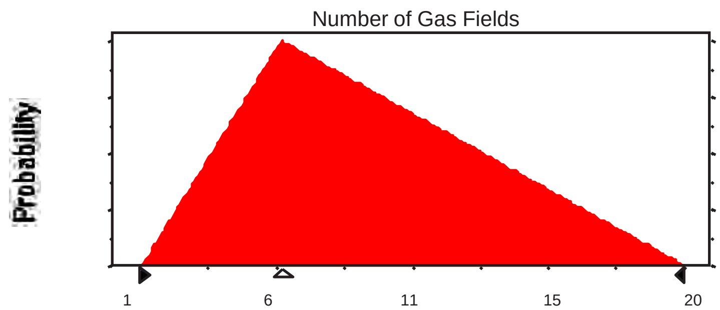
Minimum	1
Likeliest	6
Maximum	20

Selected range is from 1 to 20

Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

61170102
North Cuba Foreland Basin
Monte Carlo Results

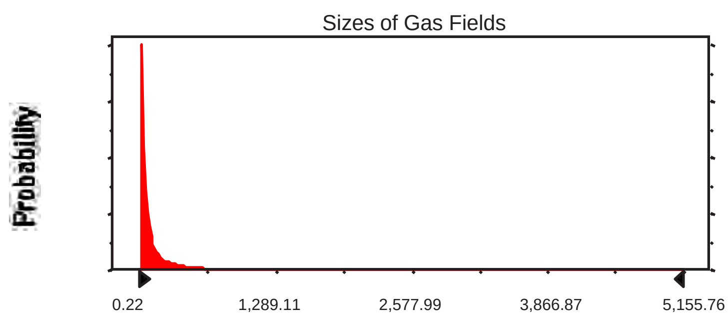
Assumption: Number of Gas Fields (cont'd)



Assumption: Sizes of Gas Fields

Lognormal distribution with parameters:		Shifted parameters
Mean	138.00	141.00
Standard Deviation	542.82	542.82

Selected range is from 0.00 to 5,994.00 — 3.00 to 5,997.00



Appendix 5. Detailed assessment results for North Cuba Foreland Basin AU.—Continued

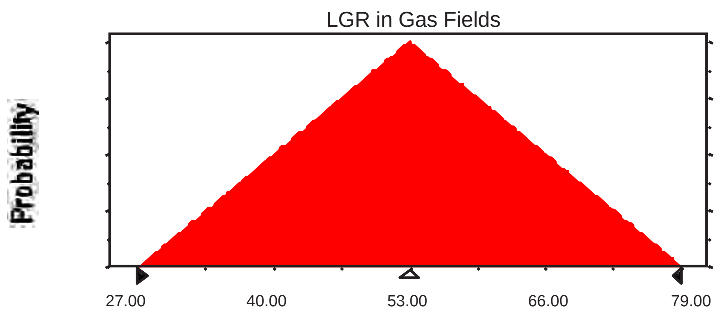
61170102
North Cuba Foreland Basin
Monte Carlo Results

Assumption: LGR in Gas Fields

Triangular distribution with parameters:

Minimum	27.00
Likeliest	53.00
Maximum	79.00

Selected range is from 27.00 to 79.00



End of Assumptions

Simulation started on 10/20/04 at 13:58:18
Simulation stopped on 10/20/04 at 14:03:07

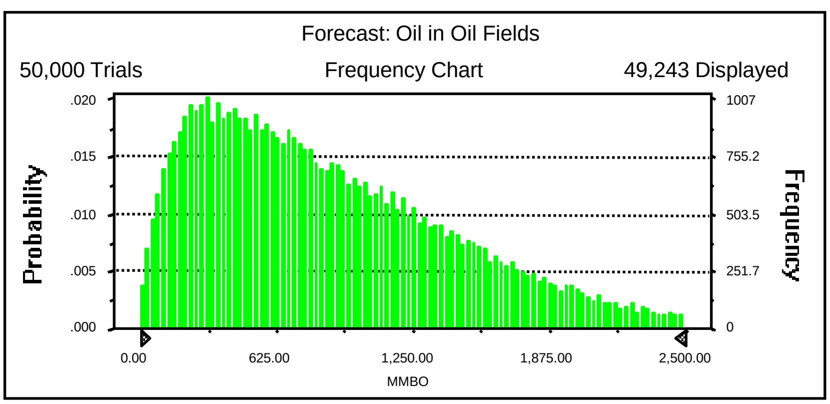
Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.

61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Forecast: Oil in Oil Fields

Summary:
Display range is from 0.00 to 2,500.00 MMBO
Entire range is from 1.61 to 4,415.64 MMBO
After 50,000 trials, the standard error of the mean is 2.72

Statistics:	Value
Trials	50000
Mean	883.13
Median	759.73
Mode	---
Standard Deviation	607.81
Variance	369,431.57
Skewness	0.97
Kurtosis	3.91
Coefficient of Variability	0.69
Range Minimum	1.61
Range Maximum	4,415.64
Range Width	4,414.02
Mean Standard Error	2.72



Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Forecast: Oil in Oil Fields (cont'd)

Percentiles:

Percentile	MMBO
100%	1.61
95%	131.66
90%	207.61
85%	272.60
80%	336.72
75%	402.92
70%	468.51
65%	538.04
60%	608.79
55%	683.56
50%	759.73
45%	843.73
40%	929.93
35%	1,027.58
30%	1,131.79
25%	1,246.37
20%	1,377.98
15%	1,532.77
10%	1,733.12
5%	2,036.87
0%	4,415.64

End of Forecast

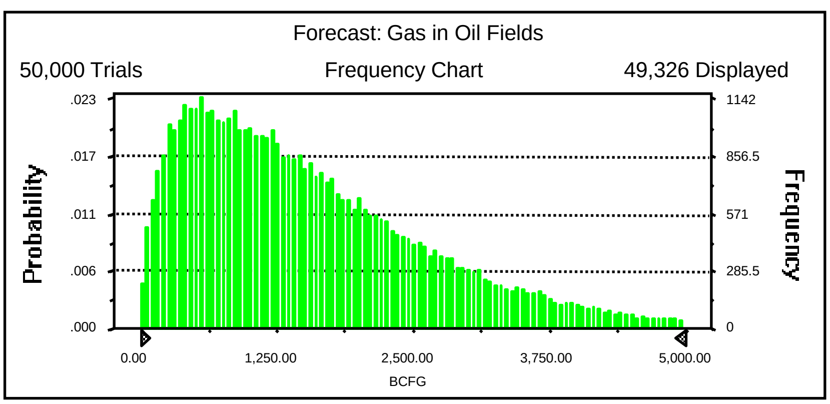
Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Forecast: Gas in Oil Fields

Summary:
Display range is from 0.00 to 5,000.00 BCFG
Entire range is from 2.27 to 10,119.49 BCFG
After 50,000 trials, the standard error of the mean is 5.20

Statistics:	Value
Trials	50000
Mean	1,588.79
Median	1,330.19
Mode	---
Standard Deviation	1,162.40
Variance	1,351,166.81
Skewness	1.22
Kurtosis	4.89
Coefficient of Variability	0.73
Range Minimum	2.27
Range Maximum	10,119.49
Range Width	10,117.22
Mean Standard Error	5.20



Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Forecast: Gas in Oil Fields (cont'd)

Percentiles:

Percentile	BCFG
100%	2.27
95%	221.42
90%	349.31
85%	466.68
80%	579.46
75%	694.98
70%	816.58
65%	935.38
60%	1,064.31
55%	1,195.06
50%	1,330.19
45%	1,477.15
40%	1,631.74
35%	1,800.60
30%	1,997.66
25%	2,210.40
20%	2,465.82
15%	2,773.79
10%	3,180.77
5%	3,841.07
0%	10,119.49

End of Forecast

Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

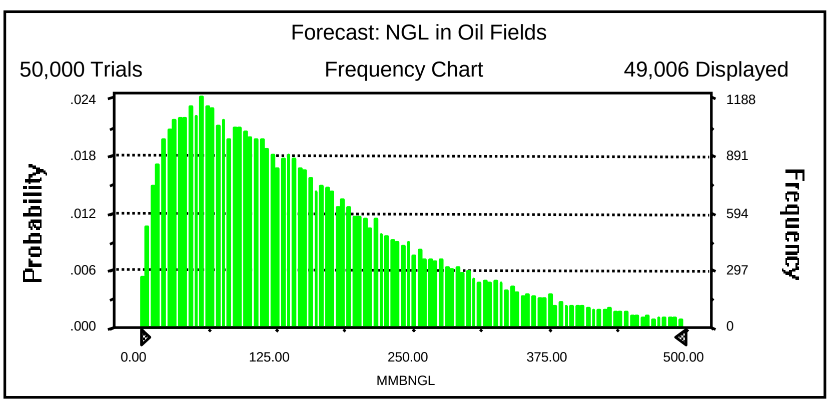
61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Forecast: NGL in Oil Fields

Summary:

Display range is from 0.00 to 500.00 MMBNGL
Entire range is from 0.25 to 1,289.69 MMBNGL
After 50,000 trials, the standard error of the mean is 0.55

Statistics:	Value
Trials	50000
Mean	158.90
Median	129.67
Mode	---
Standard Deviation	123.34
Variance	15,212.78
Skewness	1.46
Kurtosis	6.10
Coefficient of Variability	0.78
Range Minimum	0.25
Range Maximum	1,289.69
Range Width	1,289.43
Mean Standard Error	0.55



Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Forecast: NGL in Oil Fields (cont'd)

Percentiles:

Percentile	MMBNGL
100%	0.25
95%	20.71
90%	33.00
85%	44.55
80%	55.66
75%	66.42
70%	78.05
65%	90.41
60%	102.58
55%	115.45
50%	129.67
45%	143.83
40%	159.15
35%	176.46
30%	195.97
25%	218.46
20%	245.89
15%	279.25
10%	324.78
5%	399.05
0%	1,289.69

End of Forecast

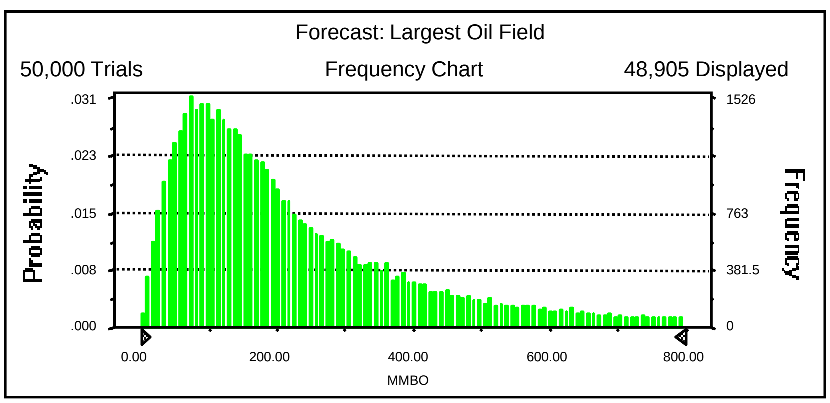
Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Forecast: Largest Oil Field

Summary:
Display range is from 0.00 to 800.00 MMBO
Entire range is from 1.61 to 999.77 MMBO
After 50,000 trials, the standard error of the mean is 0.86

Statistics:	Value
Trials	50000
Mean	233.57
Median	174.28
Mode	---
Standard Deviation	191.98
Variance	36,855.55
Skewness	1.55
Kurtosis	5.28
Coefficient of Variability	0.82
Range Minimum	1.61
Range Maximum	999.77
Range Width	998.16
Mean Standard Error	0.86



Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Forecast: Largest Oil Field (cont'd)

Percentiles:

Percentile	MMBO
100%	1.61
95%	38.25
90%	55.63
85%	70.34
80%	83.84
75%	97.41
70%	111.47
65%	125.67
60%	140.50
55%	156.61
50%	174.28
45%	192.96
40%	215.05
35%	241.10
30%	272.11
25%	308.37
20%	354.54
15%	413.63
10%	504.24
5%	654.12
0%	999.77

End of Forecast

Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

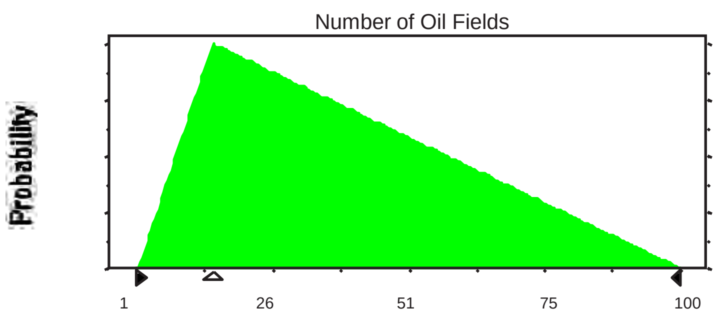
Assumptions

Assumption: Number of Oil Fields

Triangular distribution with parameters:

Minimum	1
Likeliest	15
Maximum	100

Selected range is from 1 to 100



Assumption: Sizes of Oil Fields

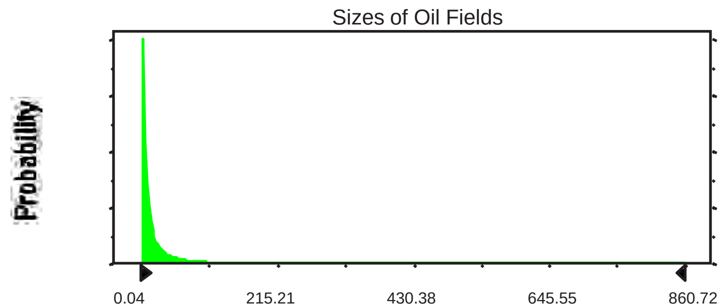
Lognormal distribution with parameters:		Shifted parameters
Mean	23.61	24.11
Standard Deviation	89.89	89.89

Selected range is from 0.00 to 999.00 — 0.50 to 999.50

Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Assumption: Sizes of Oil Fields (cont'd)

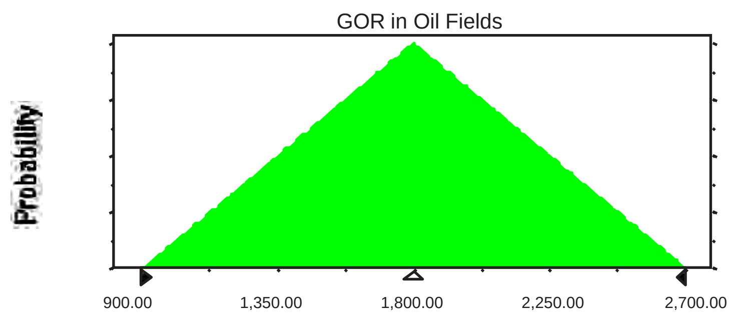


Assumption: GOR in Oil Fields

Triangular distribution with parameters:

Minimum	900.00
Likeliest	1,800.00
Maximum	2,700.00

Selected range is from 900.00 to 2,700.00



Appendix 6. Detailed assessment results for North Cuba Platform Margin Carbonate AU.—Continued

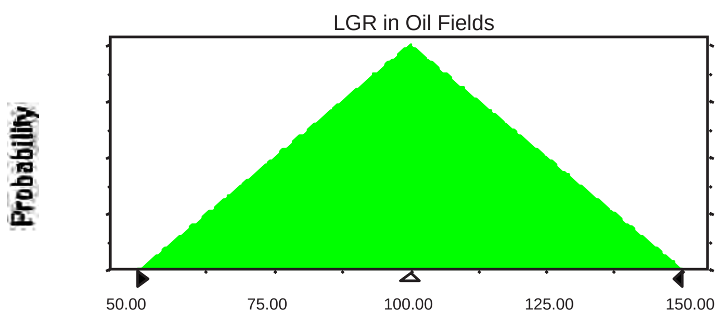
61170103
North Cuba Platform Margin Carbonates
Monte Carlo Results

Assumption: LGR in Oil Fields

Triangular distribution with parameters:

Minimum	50.00
Likeliest	100.00
Maximum	150.00

Selected range is from 50.00 to 150.00



End of Assumptions

Simulation started on 10/20/04 at 13:52:01
Simulation stopped on 10/20/04 at 13:55:23

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