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# LOWER CONGO BASIN, DEEPWATER EXPLORATION PROVINCE, OFFSHORE WEST AFRICA [1]

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## Abstract

The Lower Congo Basin lies offshore of the west coast of Africa and covers 115,000 square kilometers from the Republic of Congo to central Angola, in water depths extending to over 3500 meters. A large number of oil and gas fields occur in the basin (14 MMMBOEG produced and proven).

Two main producing trends have been discovered. The first, discovered in Block 0 in Cabinda, Angola over 30 years ago, produces from Cretaceous reservoirs in water depths less than 200 meters.

In the past four years, approximately 50 exploratory and appraisal wells have been drilled in the Lower Congo Basin Tertiary deepwater turbidite trend, which is associated with ancient deepwater channel deposition of the Congo River fan. At least 21 new oil fields have been discovered in the deepwater trend, in water depths between 200 and 1500 meters. Three-dimensional seismic data is the key to mapping these complex turbidite channel prospects. Significant areas of this new province remain undrilled, with numerous channels and trap features. Structural traps (fault truncations, channel drape over structural highs, and salt domes) dominate. Reservoirs are complex high quality turbidite sand systems. Source rocks occur in three separate intervals (Cretaceous Bucomazi and Iabe, and Tertiary Malembo formations).

The first field to produce from the turbidite trend - Kuito field in Block 14, Cabinda, Angola, discovered in April 1997 by Chevron (Operator) and partners Sonangol, Agip, Total, and Petrogal- will go on stream in November 1999.

## Introduction

A series of conditions have converged in time to produce one of the most competitive and successful exploration plays in recent history of the oil business. These conditions are:

- The recognition of geologic elements conducive to hydrocarbon occurrence in a new area
    - Active, world class petroleum system with multiple source rocks

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– Widely distributed, excellent quality, deepwater turbidite sandstone reservoir rocks

– Complex tectonic history with salt dynamics, producing multiple structural trends and a myriad of traps across the basin

♦ Advances in technology which enable exploration and development of oil fields in deepwater settings

♦ Support of the government for the petroleum industry in Angola

These conditions have converged in the Lower Congo Basin deepwater trend, and the world's oil companies have come to Angola to chase this new and exciting exploration play that has opened up what promises to be a major oil-producing province.

The Lower Congo Basin (Figure 1) is presently one of the hottest and most successful exploration plays in the world. Continuous announcements of discoveries have taken place over the last several years in Blocks 14, 15, 16, 17 and 18 in Angola, and Haute Mer in the Republic of Congo. Technical risk in the deepwater trend appears to be very low with 36 exploration wells drilled, 25 potential discoveries that encountered testable hydrocarbons (Figure 2), and up to 21 commercially developable accumulations. These are remarkable numbers and have driven the excitement and competition in the basin.

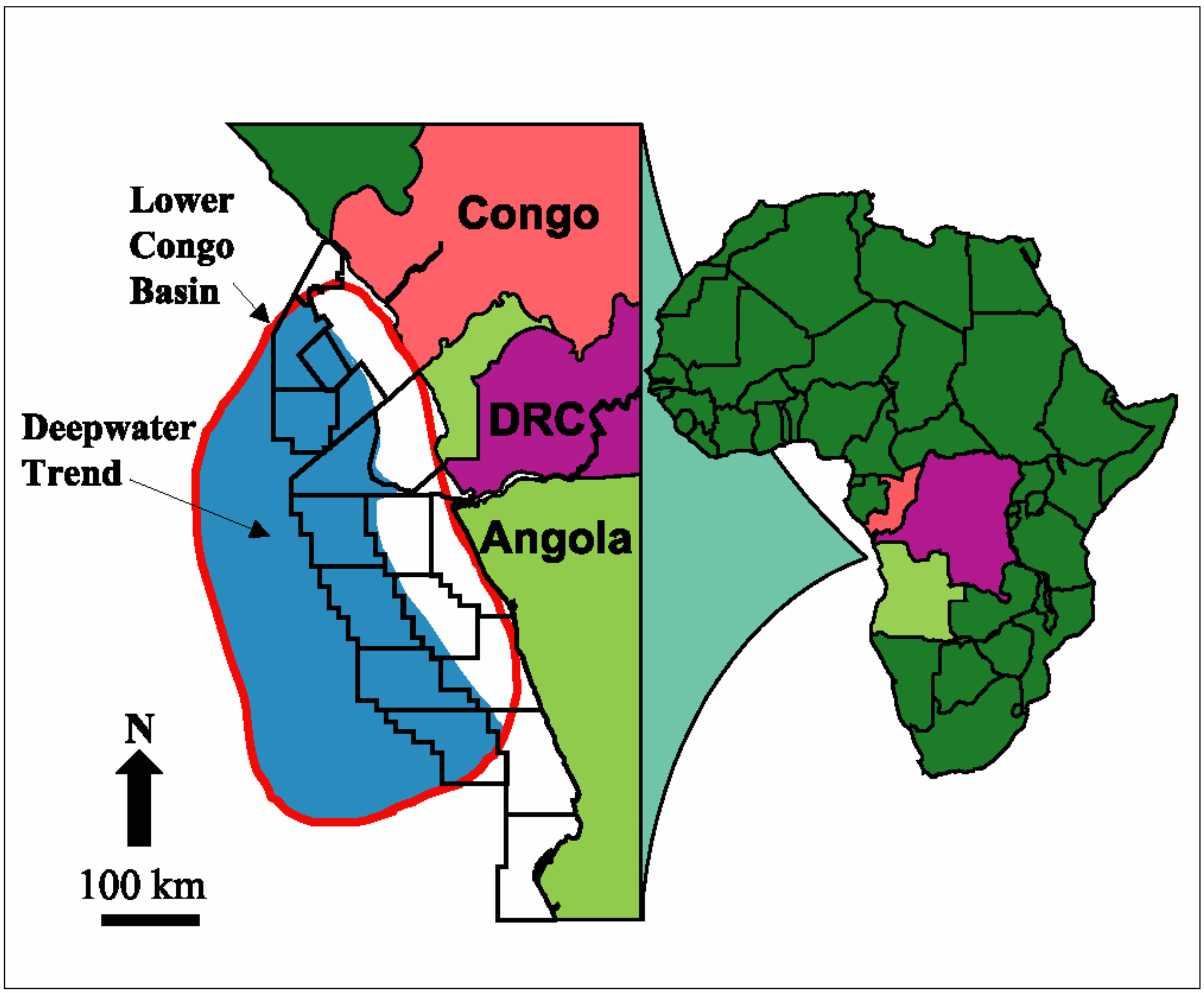


**Figure 1: Index map of Africa with location of Lower Congo Basin. Deepwater exploration trend shown in blue. Outline of offshore exploration blocks shown in black.**

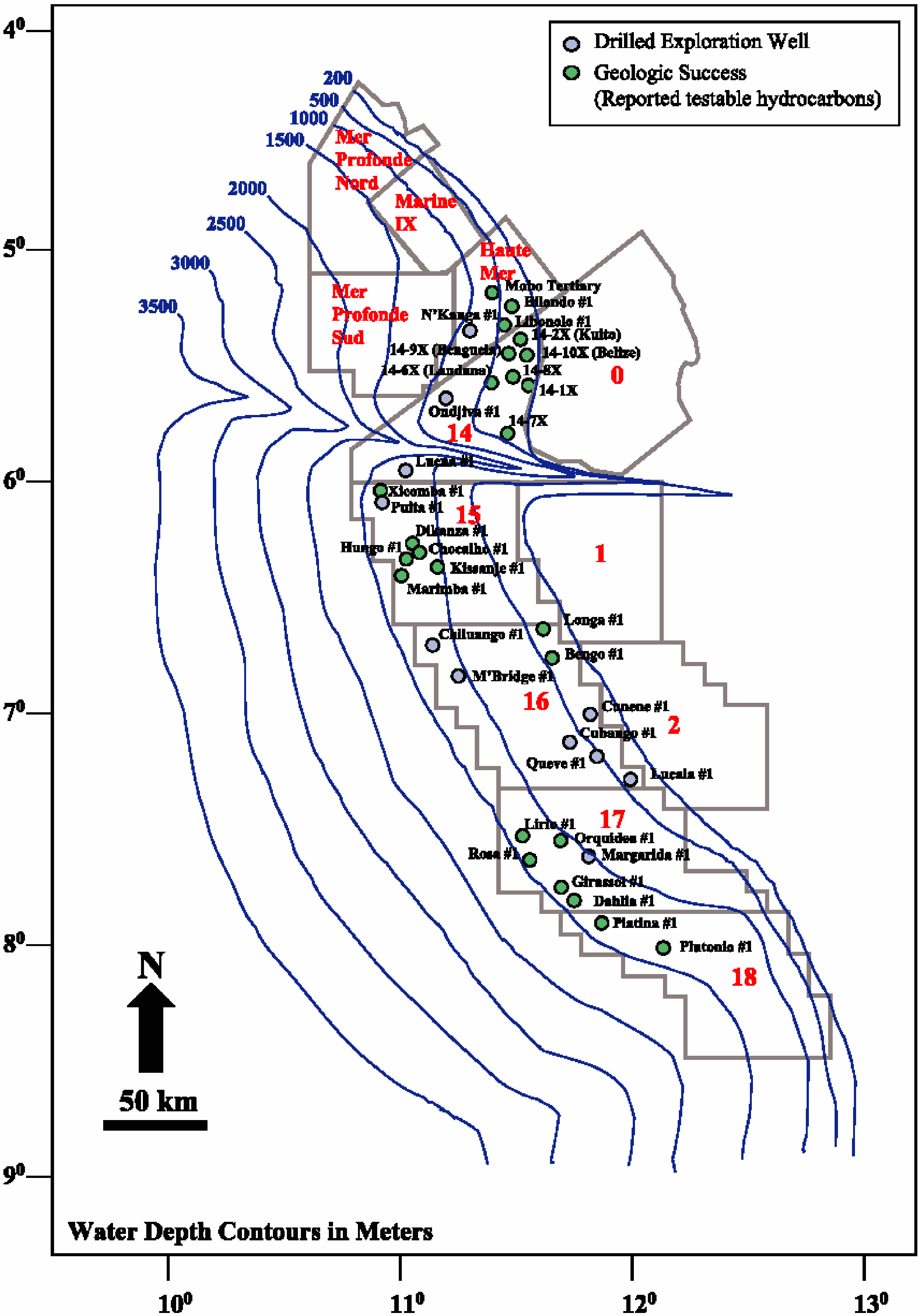


**Figure 2: Index map of Lower Congo Basin showing water depths contours, exploration blocks and deepwater Tertiary exploratory wells.**

Several fields announced to date have been characterized as giant accumulations with recoverable reserves of 500 MMBO or greater (Girassol and Dahlia in Block 17, and Kuito in Block 14). The mean size of fields discovered to date is at least 200 MMBO of recoverable reserves. Several fields are vertically stacked, and grouped geographically around structural traps. These characteristics will enable production facilities to tap multiple accumulations, adding to the value of the facilities through time. Fields in this basin will benefit from recent technical advances in deepwater development technology that enable production in greater than 1000 meters of water. As exploration progresses into prospective areas with water depths up to 3500 meters, this basin will provide the impetus for further advances in engineering technology to produce the reserves. The benign ocean environment characteristic of this portion of the western coast of Africa will enable technology to push to greater water depths than might be practical in more adverse environments. Once infrastructure is in place in the deepwater across the basin, satellite fields and smaller accumulations will become commercially viable.

Most of the basin has been covered with modern 3-dimensional seismic data over the last five years. When combined with the powerful computer hardware and software now available to visualize and interpret the data, this has enabled a high level of understanding of the geology and prospectivity of the deepwater trend.

Due to the competitive nature of the leasing activity in the Lower Congo Basin, there is sparse information published about the exploration play, or the different fields discovered. Much perception about the basin is based upon available reports. The most insight into the Lower Congo Basin trend was provided at the AAPG Convention in Rio de Janeiro, Brazil in 1998. A number of papers were presented by representatives of companies exploring the basin, as well as Sonangol, the Angolan National oil company (see Barrett et al 1998, Chevron; Cole, et al 1998, BHP; David, 1998, Sonangol; Dominey et al 1998, Shell; Hartman et al 1998, Exxon; Marton, G. and G. Tari, 1998, Amoco; Raillard et al 1998, Elf; and Raposo, A. and M. Inkollu, 1998, Sonangol).

This paper will provide an overview of the Lower Congo Basin and will endeavor to give a regional perspective of the deepwater turbidite exploration play, using information gleaned from industry activity, and Chevron and Sonangol experience in the basin. The companies involved in this play have aggressively taken leases and drilled wells in the deepwater trend in the Lower Congo Basin of Angola and the Republic of Congo, but significant areas of the basin remain undrilled.

## Geologic Setting

The Lower Congo Basin lies offshore of the west coast of Africa and covers 115,000 square kilometers from the Republic of Congo to central Angola, in water depths extending to over 3500 meters. The Lower Congo Basin is within the Congo Basin proper, which is a sub-basin of the Aptian Salt Basin system that occurs along the western coast of Africa (Clifford, 1986).

The history of the Congo Basin can be divided into three main stages (Lehner and De Ruiter, 1977):

1. Rift stage, with lacustrine and alluvial deposition within graben and half-graben structural basins (Neocomian to mid-Aptian)

2. Evaporite deposition stage, developed during the transition from active rifting to thermally-induced crustal subsidence (Aptian)

3. Subsidence stage, with regional marine deposition and active extension and salt tectonics (Albian to Recent)

The stratigraphic succession for the Lower Congo Basin is shown in Figure 3.

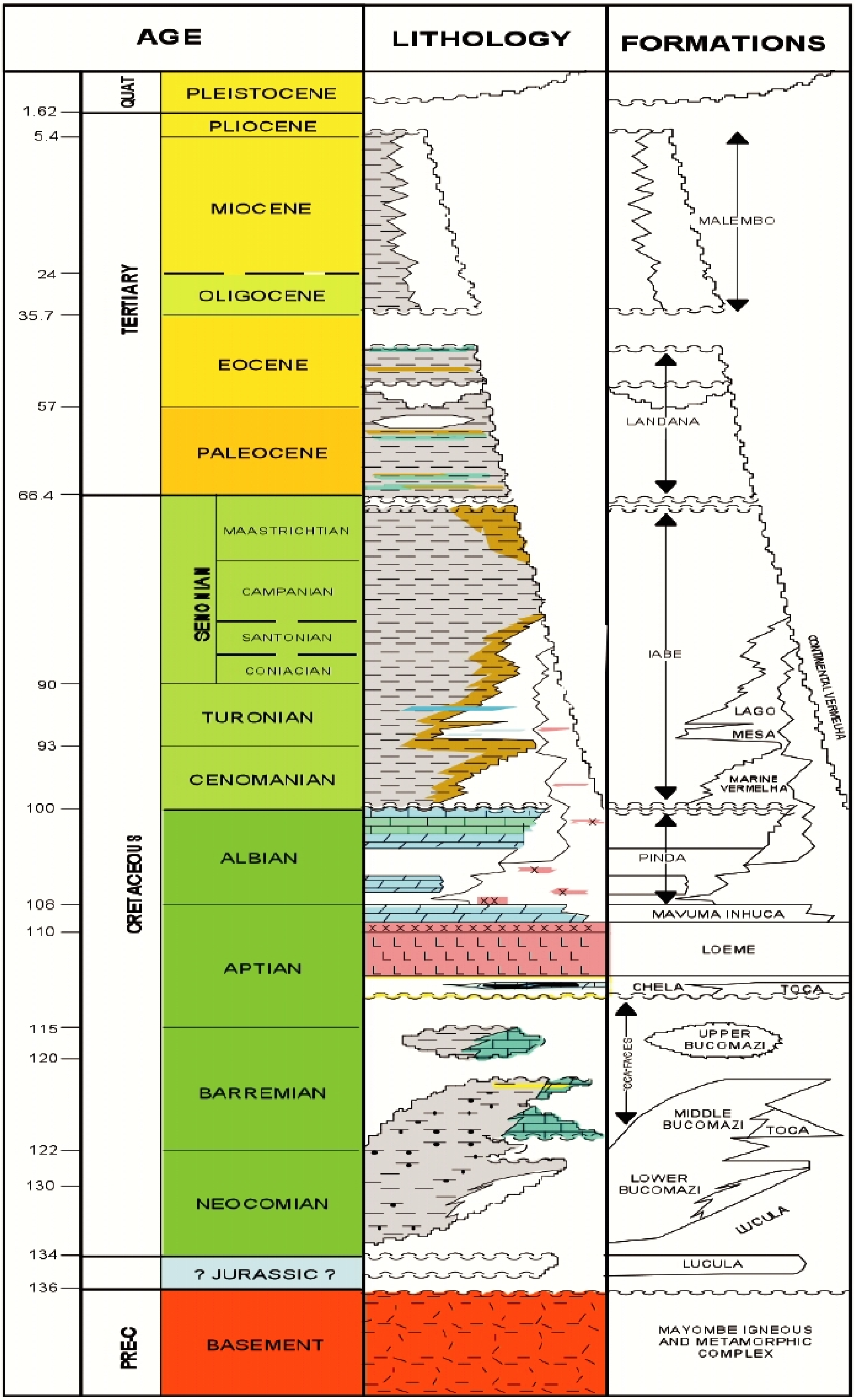


**Figure 3: Stratigraphic column of Lower Congo Basin from Cabinda, Angola well control.**

Basin development along the coast of West Africa commenced in the Late Mesozoic due to rifting and separation of the South American and African continental masses during the opening of the South Atlantic Ocean (Lehner and De Ruiter, 1977). Transverse fracture zones of the Mid-Atlantic rift segmented the rifted continental crust into a series of sub-basins. The Congo Basin is one of these sub-basins, and extends from the Republic of Congo to central Angola. It lies between the Gabon Basin to the north, and the Kwanza Basin to the south. The transition from the Congo Basin to the Kwanza Basin lies along the Ambriz spur, a NE-SW trend, located to the north of Luanda, the capital of Angola.

Similar basin development occurred on the opposing rifted margin- the eastern coast of South America. The Campos basin is one of the most significant petroleum provinces where deepwater turbidites contain world class oil fields (Pettingill, 1998a). The similarities of the Brazil margin basins (in particular the Campos and Santos basins) to the Lower Congo Basin of Angola and the Republic of Congo is compelling.

Within the rifted Congo Basin the predominant deposition sequence was silt and shale lacustrine deposits of the Bucomazi Formation (Neocomian to mid-Aptian). Active tectonism during deposition of the Bucomazi resulted in changing basin geometry and stratigraphy through time. Anoxic conditions during the end-Neocomian resulted in the deposition of a widespread organic-rich sequence in the middle portion of the Bucomazi Formation that is a primary source rock in the basin. TOC content in this interval is as high as 20% (Dale et al, 1992).

By the end of the Barremian, rift activity on the Mid-Atlantic ridge had progressed to the west enough to reduce the level of direct tectonic activity along the African passive margin. Final uplift and erosion produced a regional unconformity that is recognized on seismic and has been correlated in wells. The Chela formation sandstone and shales were deposited on this unconformity during early-Aptian.

The onset of marine deposition in the Congo Basin is denoted by deposition of the Aptian Loeme Salt Formation. This extensive evaporite sequence consists of halite, potash, and local clastics. An anhydrite layer marks the top of the sequence. The original stratigraphic thickness of the Loeme Salt is difficult to determine. The interval acts as the primary detachment surface for pervasive extensional faulting all along the eastern half of the basin. The interval can be seen on seismic data thinned and wadded up along the regional detachment surface. The Loeme Salt also becomes involved in diapir features and complex compressional structures in the deepwater portion in the western half of the basin.

Open marine conditions continued with deposition of the Pinda Formation during Albian. The Pinda Formation consists of a sequence of continental shelf clastics and carbonates. After deposition of the lower Pinda limestone and dolomite section, the shelf collapsed westward into a series of fault blocks, bounded by listric normal faults on the updip side. These fault blocks rode on the underlying Loeme Salt sequence, responding to sediment loading and development of regional west dip on the shelf. Pinda deposition continued, and was influenced by these moving fault systems, with dramatic growth sections developed against the listric faults.

In Cenomanian time depositional patterns changed from mostly carbonate-clastic rocks of the Pinda Formation to mainly siliciclastics of the Iabe Formation. Sea level remained consistent, with subsidence and deposition in balance. Depositional patterns varied spatially from nonmarine deposits to the east; nearshore and shoreface environments of the Vermelha reservoir sandstones in a band along present shallow water areas; and shale and silts in the western portion of the basin in present day deeper water (Dale et al, 1992). The Iabe Formation has shale intervals that contain organic facies, providing an additional source rock to the stratigraphic section.

Subsidence of the passive margin of West Africa, in the Congo Basin area, continued through the late Cretaceous-Eocene, with marine deposition of the Landana Formation occurring across the basin. The Landana interval is sparsely drilled in the basin, and may have turbidite sediments in the deepwater area. A major unconformity at the base of the Oligocene section, due to a significant lowering of sea level, marks the beginning of a period of marine deposition driven by sea level changes, which continues to present day.

Continued subsidence during this phase provided significant accommodation space for a large volume of Tertiary sediment into the Congo Basin. The highest sedimentation rate occurred during the Miocene, up to 6000m of section deposited in the Malembo Formation. The large volume of sediment was deposited from the Congo River, which drains a vast area of south central Africa.

Throughout the Miocene, the Congo River spread submarine turbidite deposits across the basin, with the vector of sedimentation varying with time within an arc from the southwest to northwest. Deposition of the deepwater turbidite facies occurs in a channel-dominated submarine fan system. Regional assessments by Chevron tie the depositional sequence to the Miocene sea-level curves (Figure 4, Ewins and Minck, 1998) and provide a methodology to model and predict depositional geometry and sand content. Sand systems are generally deposited at sequence boundaries in cut and fill channels with internal meandering geometry common (Figure 5), and variable net:gross of sand content both vertically and laterally. Some channel systems exhibit more linear channel/levee geometry (Figure 5). Differential compaction is evident on seismic data in higher net:gross intervals and where channel meanders are stacked vertically (Figure 6). Outside of channel systems the predominant sediment is shale, forming vertical and lateral seals to sand-filled channels. The shales of the Malembo Formation also provide a third source rock to the Congo Basin.

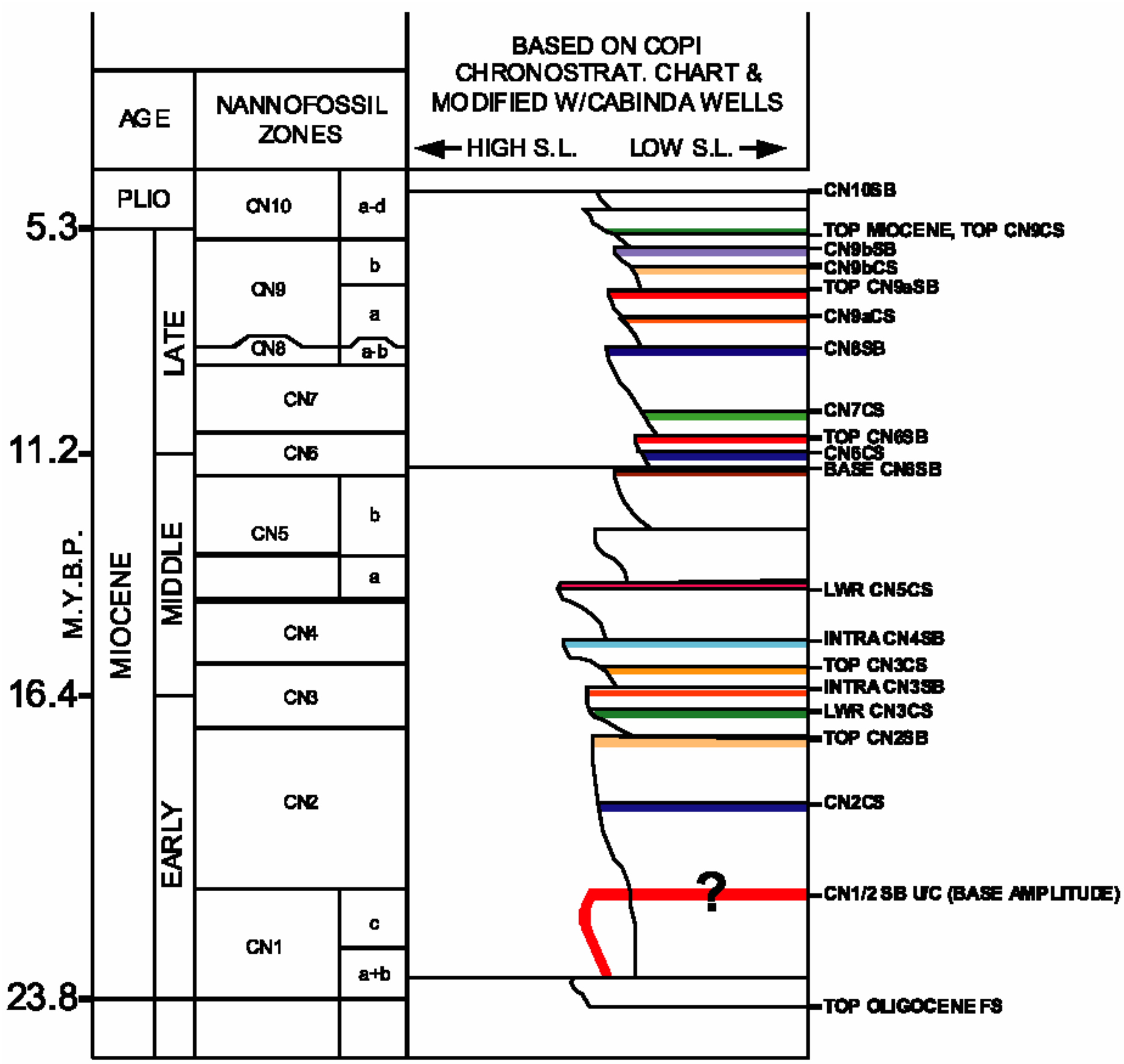


**Figure 4: Chronostratigraphic chart of Miocene sea level curves built from Cabinda well control. CS denotes condensed sections, SB denotes sequence boundaries, and FS denotes flooding surfaces.**

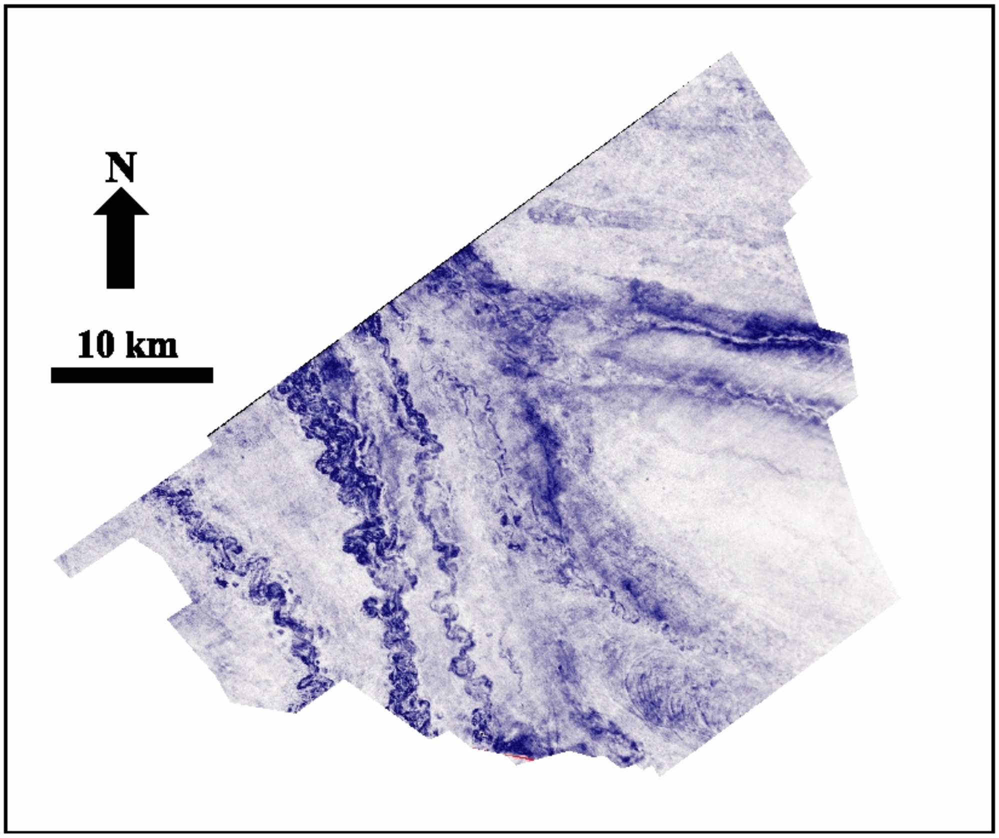


**Figure 5: Amplitude extraction of Miocene sequence boundary in Block 14 illustrating depositional geometries. Note meandering channel systems in western portion of data, and linear channel/levee systems to east.**

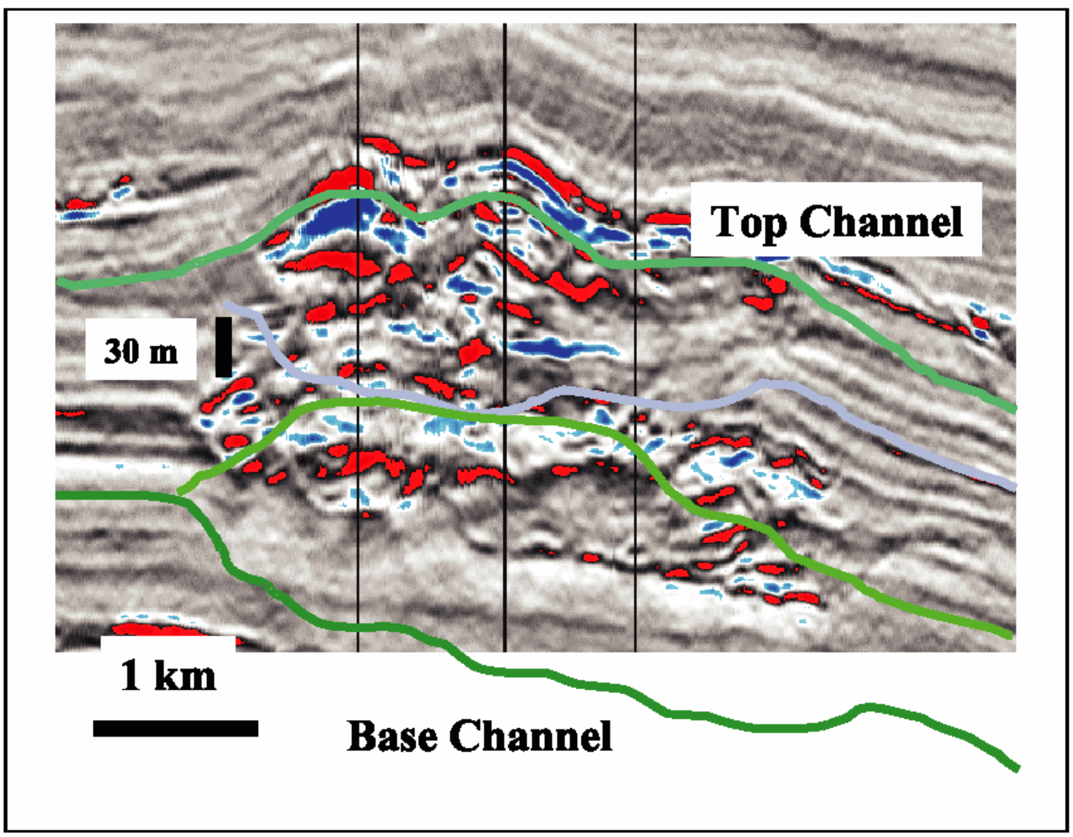


**Figure 6: Seismic line through Kuito field. Line is oriented across depositional axis of channel. Note differential compaction and stacking of amplitude packages that indicate sandy turbidite channel systems.**

From Upper Miocene to present, the Congo River cut large erosional canyons into the submarine fan during sea level drops. The modern Congo Canyon provides a good analog for these features. The Congo submarine canyon has been recognized since 1886 when a sea floor cable route was surveyed (Heezen et al, 1964). The canyon runs for over 250 kilometers offshore (Figure 7), and is actively depositing sediments on the Angolan Abyssal Plain in 4000 m of water (Heezen et al, 1964). Cable breaks as far as 200 kilometers from shore have occurred, due to turbidity currents during times of maximum river discharge. The Miocene and Pliocene canyons were filled with pelagic sediment and sandy turbidite flows during subsequent rises in sea level.

The high sedimentation rate and continued subsidence during the Miocene caused renewed basin-wide extension on the Aptian Loeme Salt detachment, with major extensional basins developing along the eastern margin of the deepwater province. This extension, which was greatest east of Block 16 and decreased to the north and south, was compensated to the west by compressional structures and salt tectonics in the western portion of the basin. A compressional wedge, very similar in geometry to the Sigsbee Escarpment in the Gulf of Mexico, exists along the western side of the basin, and denotes the leading edge of deformation. A significant area of salt-cored compressional structures, thrust faults and folds, as well as mobilized and deformed salt diapirs occurs in the ultradeep water, directly outboard of the greatest amount of extension (Figure 7).

Extension and compression continued throughout the Tertiary and strongly influenced deposition of turbidites. Depocenters formed which collected turbidite deposits through time, providing stacking of channel systems. Some growth occurred after deposition, with channels crossing structure with little or no deflection and salt domes piercing channels. This relationship of concurrent deposition and structural growth across the basin has enhanced the potential for numerous traps.

The pervasive extensional and compressional tectonics created a large number of traps in the basin. These traps are associated with rollover into extensional faults; channel truncation against updip faults; compaction closures over deeper Cretaceous-cored structures; and traps over and around salt domes, salt-cored thrusted folds, and turtle structures. In general, structural traps with a component of stratigraphic trapping dominate in the basin. Structural deformation continues today with examples of sea bottom expression of salt domes and surface scarps of active faults. These structural age relationships must be studied carefully to avoid the potential for trap breaching due to active faulting.

The existence of source rocks stacked vertically throughout the stratigraphic section in the Cretaceous (Bucomazi and Iabe formations) and the Oligo-Miocene (Malembo Formation), provides the world-class petroleum system that has created the large volume of hydrocarbons discovered and produced to date in the basin (14 MMMBOEG produced and proven). The network of faults that occur in the basin facilitates migration of hydrocarbons up through the section, from deeper mature source rocks. Migration from Bucomazi source rocks (pre-salt) is enabled by windows in the regional Aptian Salt due to thinning and faulting along the regional detachment. Within the Malembo section, direct migration from source rock shales to reservoir sands can occur.

Data gathered on discoveries made in the deepwater trend indicate that oil quality varies within the basin (Figure 8). Generally, discoveries made in sand systems buried deeper below the mudline contain higher quality oil (higher API gravity) than shallow traps. This relationship may be due to original maturity of the migrated oils, but also is related to the effects of temperature on biodegradation of shallow trapped oils. It is also possible that some fields have received multiple charges of hydrocarbons, and have oils from more than one source rock.

If we look at the history of the basin, we can understand how this occurs. The vertical distribution of source rocks through the rock column means that different source intervals generated hydrocarbons through time as burial progressed. For example, the deep Tertiary extensional basins will have more Malembo source rocks in the oil window, forming local generating systems with the potential for higher quality oils, but the deeper Iabe and Bucomazi source rocks may be pushed through the oil window into gas or condensate generation. The middle and upper Malembo may not be buried deep enough in some portions of the basin to put these source rocks in the oil window, therefore any traps in these intervals must be charged by more complex migration systems along faults from deeper source rocks. The relationship of burial history, source rock maturity, and migration is a critical one due to the impact that oil quality has on the value of the crude oil produced. With most of the Lower Congo Basin occurring in technically challenging water depths, the value of the crude will have a significant impact on the economics of fields.

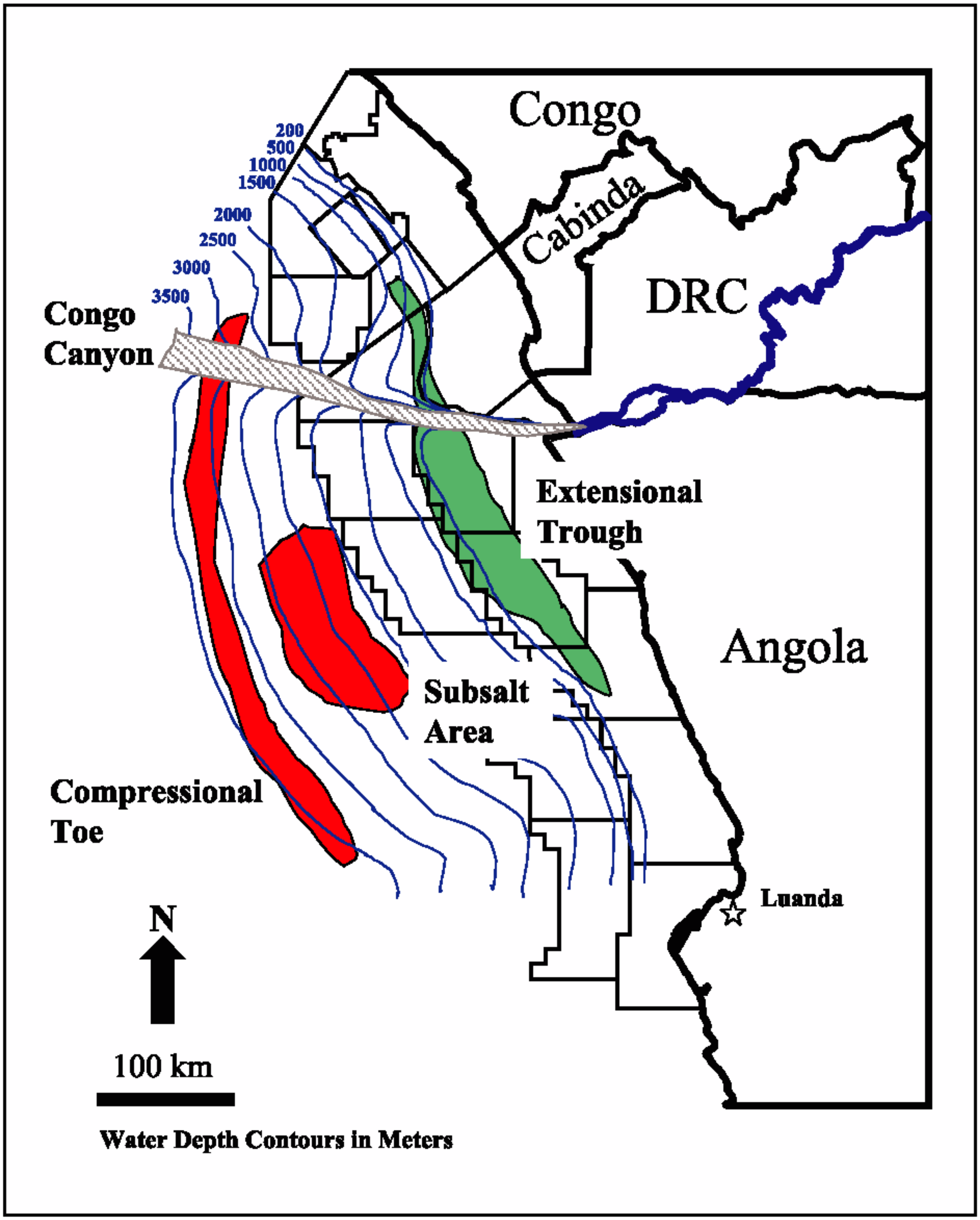


**Figure 7: Index map of Lower Congo Basin illustrating position of Congo Canyon, Tertiary extensional trough, compressional toe, and subsalt area. Water depth contours and exploration block outlines are shown.**

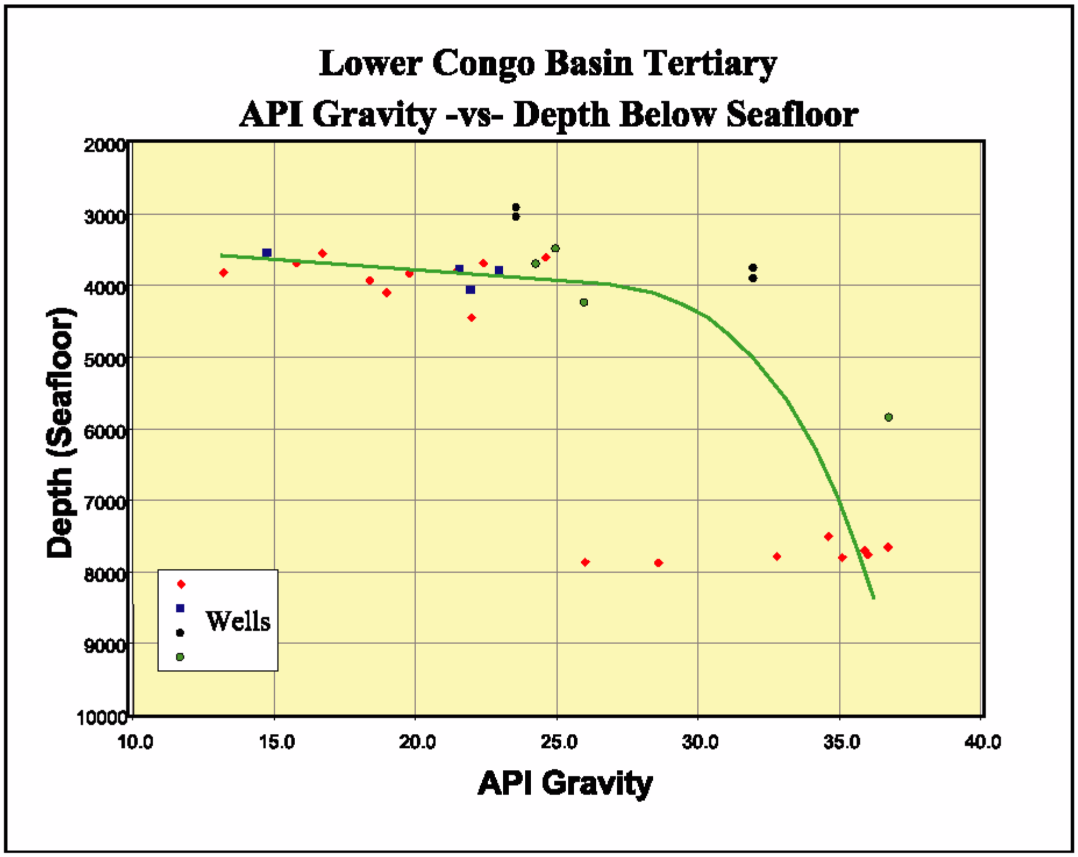


**Figure 8: Chart plotting the relationship of oil API gravity versus depth below sea bed for Lower Congo Basin Tertiary wells. Note differentiation of oil quality with depth, with deeper reservoirs containing higher gravity oils. Low gravity oil in shallow reservoirs may be caused by low maturity source rocks, as well as biodegradation in shallow reservoir oils.**

## Exploration History

A large number of oil and gas fields occur in the Congo Basin. Two main productive trends have been discovered (Figure 9). The first, the Cretaceous pre-salt and post-salt trend, stretches 350 kilometers along the coastline in water depths less than 200 meters, from the Republic of Congo to central Angola. The second occurs in the Lower Congo Basin deepwater Tertiary turbidite trend and stretches 300 kilometers from the Haute Mer block in the Republic of Congo to Block 18 in central Angola, in water depths greater than 200 meters. Although the Cretaceous producing trend has been explored for over 30 years, additional exploratory potential exists with acquisition of new 3-dimensional seismic data. The Tertiary deepwater turbidite trend is not mature, with three-quarters of the prospective area of the trend still undrilled. Further drilling will certainly expand the Tertiary deepwater turbidite trend significantly.

Exploration commenced in the Congo Basin offshore province when Gulf Oil Corporation, operating the Cabinda concession under the name Cabinda Gulf Oil Company (Cabgoc) drilled an exploratory well in 1966 based upon marine geophysical data. The well was a discovery (Limba field) in the Cenomanian Vermelha sandstone (post-salt section). The deeper pre-salt section was discovered in 1967 at the Malongo North field. Cabgoc exploration for large pre-salt fields continued through the late 1960's and early 1970's with the discovery of the giant Malongo West field in 1970 and the giant Takula field in 1971 (Dale et al, 1992). In 1979, drilling in Takula field resulted in the discovery of the Pinda (post-salt) accumulation. Exploration has proceeded on the trend through the 1980's and 1990's, with 3-dimensional seismic data driving activity. Presently, the pre-salt and post-salt Cretaceous reservoirs account for 500,000 BOPD in the Block 0 Cabinda Concession, with additional production along trend in the Republic of Congo to the northwest, and the Democratic Republic of Congo, and Angola to the southeast.

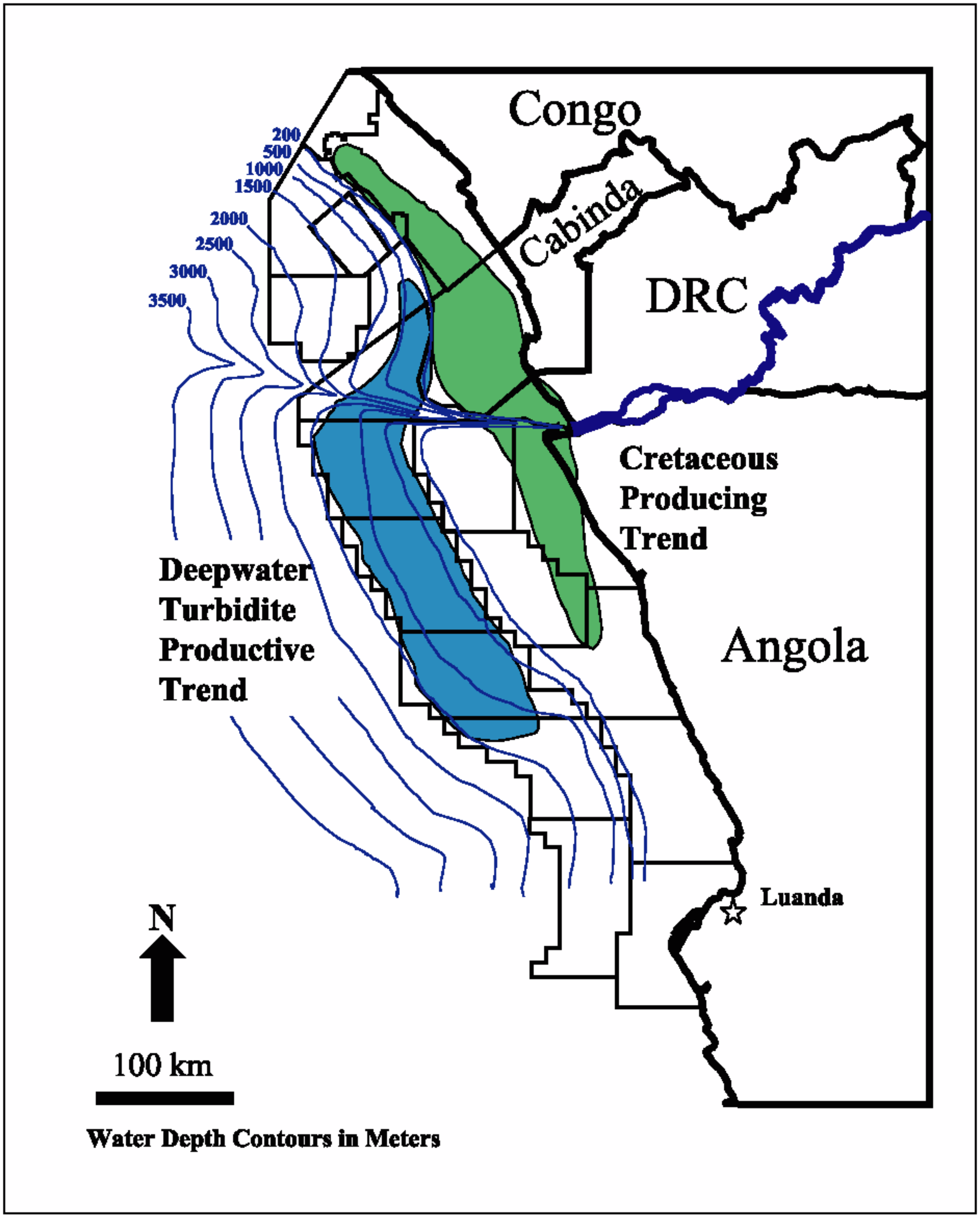


**Figure 9: Index map of Lower Congo Basin illustrating position of Cretaceous (post-salt and pre-salt) producing trend, and present area of Tertiary turbidite discoveries. Water depth contours and exploration block outlines are also shown.**

Interest in the Lower Congo Basin deepwater trend simmered during the early-1990's as companies picked up blocks in the 200-1500 m water depths (blocks 14, 15, 16, 17, and 18 in Angola; and Haute Mer in the Republic of Congo). Expectations were high due to the fact that the basin was already a proven petroleum province in the shallow water area. The continuation of this proven petroleum system from shallow water to the deepwater area, and whether the Congo River had delivered enough sand to the submarine fan to produce significant reservoir potential, were the key questions waiting to be answered by drilling.

The discovery of Girassol in Block 17 by Elf and partners in April 1996 brought interest in the trend to a high level. The Girassol accumulation was reported to be a giant accumulation of 32 API gravity oil. Discovery of the Bengo accumulation in 1996 by Shell and partners in Block 16 was reported. Activity increased in 1997 with the discovery of Kuito and Landana in Block 14 by Chevron and partners and Dahlia and Rosa in Block 17. An expansion of exploration in the basin in 1998 saw four new discoveries in Block 15 (Kissanje, Marimba, Hungo, and Dikanza) by Exxon and partners, as well as the discovery of Benguela and Belize in Block 14. The most recent drilling in 1999 has resulted in additional discoveries in Block 15 (Xicomba and Chocalho), Block 17 (Lirio) and Block 18 (Platina and Plutonio).

Since 1996, 36 exploration wells have been drilled in the Lower Congo Basin Tertiary deepwater trend, in water depths between 200 and 1500 meters. Technical risk in the basin appears to be very low. Out of these wells, 25 may be geologic successes (encountered testable hydrocarbons), and up to 21 are commercially developable accumulations. This means geologic risk for exploratory wells (the risk to encounter testable hydrocarbons) is 1:1.4 and commercial risk (the risk that a field will contain enough hydrocarbons to be developed) is 1:1.7. Several fields announced to date have been characterized as giant accumulations with recoverable reserves of 500 MMBO or greater (Girassol and Dahlia in Block 17, and Kuito in Block 14). The mean size of fields discovered to date is at least 200 MMBO of recoverable reserves.

Announcements on field developments have only been forthcoming for Kuito field in Block 14, and Girassol field in Block 17.

The first field to produce from the turbidite trend will be Kuito field in Block 14, Cabinda, Angola, discovered in April 1997 by Chevron (Operator) and partners Sonangol, Agip, Total, and Petrogal. Reserves for the entire Kuito accumulation are estimated at 500 MMBO. Oil gravity ranges from 19-24 degrees API. The field lies in about 350 meters of water. Production will be through subsea wells to a central FPSO with export directly from offshore. The FPSO was dedicated in Singapore in August, and the field will begin production in November 1999. Benguela and Belize fields in Block 14 lie only 3-5 kilometers south of Kuito, and reserves estimates for the field complex are 300 MMBO recoverable of 24-35 degree API gravity oil. Benguela and Belize fields are presently being studied for possible development in 2001.

Girassol field in Block 17 lies in about 1400 m of water. Development plans apparently are focusing on subsea wells tied back to an FPSO, with production building to a plateau rate of 200,000 BOPD.

As the larger fields are discovered and developed in the Lower Congo Basin deepwater trend the growing infrastructure will enable exploitation of mid-size and smaller accumulations that cannot economically carry an initial exploratory well in these water depths. Much will be learned about the long-term performance of these turbidite sands as different fields come on stream across the basin. The geographic grouping of channels through the stratigraphic section around major trapping structures creates a full distribution of potential field sizes, and the existence of infrastructure will allow companies to tap into a broad inventory of prospects to keep facilities running at full capacity.

## Future Potential

Within the primary deepwater trend explored over the last four years (Blocks 14-18 in Angola and Haute Mer in the Republic of Congo), 36 exploratory wells occur in an area of approximately 24,000 square kilometers, with a well density of one well per 660 square kilometers. Three-dimensional seismic data is the key to mapping the complex turbidite channel prospects in the Lower Congo Basin, and since this part of the trend is essentially covered by 3-D surveys, it is likely that continued drilling within this area will discover new fields.

Significant areas of this new province remain undrilled (Figure 10), with numerous channels and trap features. Approximately 60,000 square kilometers of highly prospective acreage with play elements consistent with the successful Tertiary prospects in the present trend are completely unexplored. This unexplored area lies outboard of Blocks 14-18 in Angola and Haute Mer in the Republic of Congo, in water depths from 1500-3500 meters.

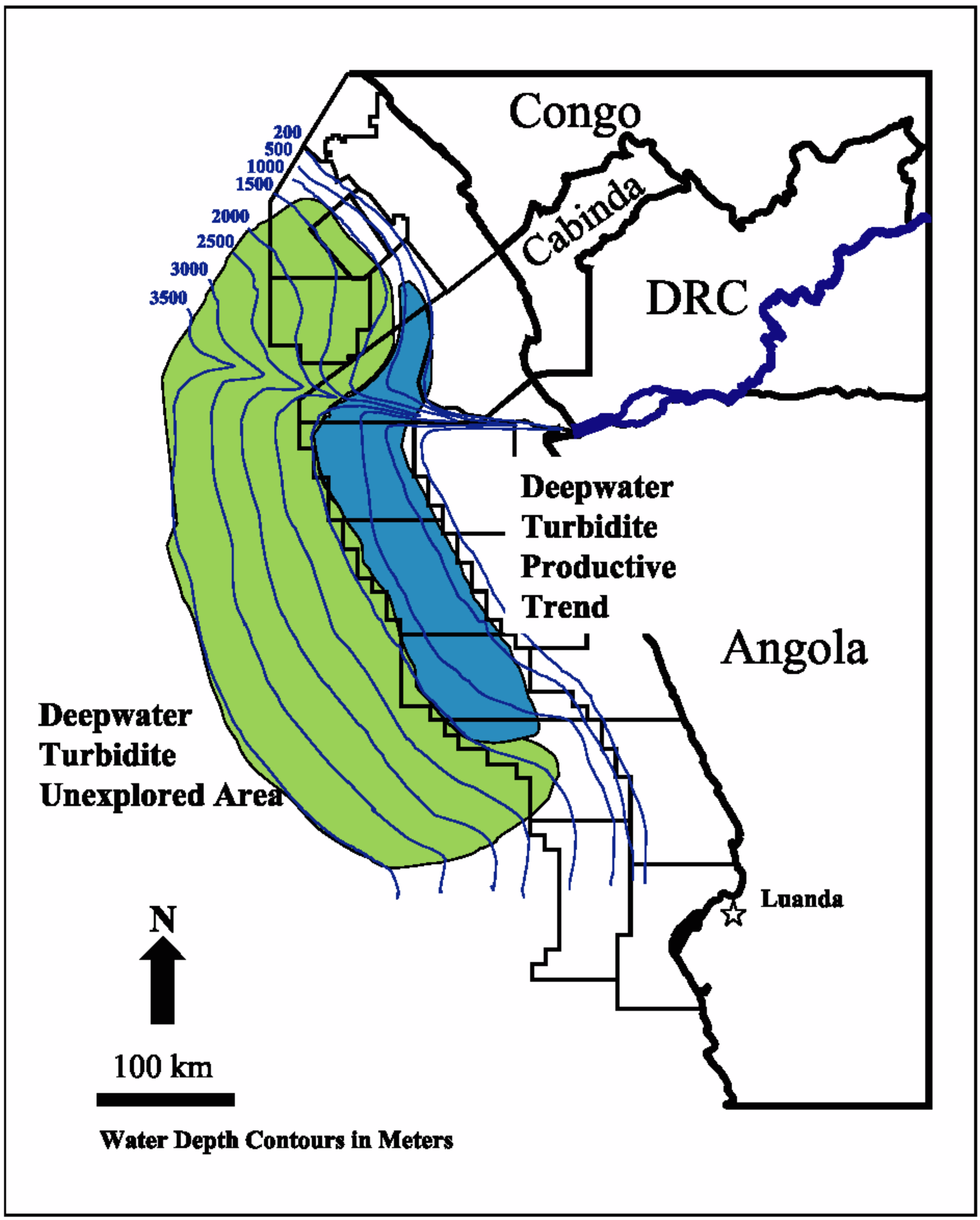


**Figure 10: Index map of Lower Congo Basin illustrating position of present area of Tertiary turbidite discoveries and remaining unexplored area. Within the area of present deepwater discoveries, well density is only 1 well per 750 square kilometers, which indicates significant area still remains to be explored. Water depth contours and exploration block outlines are also shown.**

It is apparent that present exploration efforts in the Tertiary turbidite trend are finding oil fields with combined structural and stratigraphic components of trap. Large traps associated with drape over deeper structures, rollover associated with extensional faults, fault truncation of channels, and salt-related structures are the most obvious features. Faults appear to be an important trapping mechanism, and may cause compartmentalization of fields. Stratigraphic components of trap are commonly caused by lateral pinchout of sand facies at the margin of channel deposition. Since the bulk of the rock column in the Congo submarine fan is mud/shale, with sands deposited mostly within channel systems, the lateral seals to the system should be good. In areas where channel density is high, the lateral seals may be compromised due to lateral overbank sands and crosscutting channel systems. The lowest risk for lateral seal are within isolated channel features cut into shale.

An assessment of turbidite discoveries by Pettingill (1998a;b) shows that stratigraphic trapping usually contributes significantly to a basin's ultimate reserves, although this potential may not be seen early in a basin's exploration history. Given the Lower Congo Basin success rate to date within the combined structural/stratigraphic traps, and the large area still unexplored with the same characteristics, it is likely that near term exploration will focus on these types of features. Sometime in the future, the subtle and pure stratigraphic traps will likely be understood and contribute to the prospectivity of the basin.

The existence of significant areas of subsalt will create a challenge to those companies prospecting for turbidite plays. The decrease in quality of the seismic imaging and spatial location of prospects beneath the salt overhangs will raise the geologic risk of wells, but the existence of the petroleum system and turbidite channels bordering these areas to the east means the subsalt area is still highly prospective. Companies with experience in the Gulf of Mexico subsalt play can leverage that experience to better handle the seismic imaging challenges, more accurately locate wells, and evaluate predrill risk appropriately.

The Lower Congo Basin is a world class petroleum province with giant fields discovered and significant areas still unexplored. It is probable that additional giant fields wait to be discovered in the basin, as well as a full distribution of fields of various sizes.

## Conclusions

The Lower Congo Basin deepwater turbidite trend, offshore Angola and the Republic of Congo, is one of the most successful and competitive new exploration plays in the world. Several giant discoveries have been announced in the last several years, and the success rate of exploratory wells is very high, indicating a basin with low geologic risk. Significant areas of the basin remain unexplored in water depths up to 3500 m. The challenge to companies working the trend is to evaluate the distribution of prospects and build up enough of a reserve base to drive technology advances to produce oil at a profit in these water depths.

## Acknowledgements

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