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Report for Nabirm Global LLC.

2D Seismic Interpretation and

Hydrocarbon Prospectivity Project

Block 2113A

Exploration License 58

Namibia

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1 Introduction

1.1 Study Objectives

This study has been conducted on behalf of Nabirm Global, LLC, the holder of Petroleum Exploration License (PEL) 58, Block 2113A, offshore Erongo Province, Namibia. The license block covers 5,750 km^2, with 3,600 km^2 located offshore and 2,150 km^2 located onshore. PEL 58 is located inboard of Pancontinental's PEL 37 Block and adjacent to EcoAtlantic's CBM Blocks 2013B, 2014B & 2114 (Figure 1).

The objectives of the study include:

- Integration of regional geologic and tectonic interpretations from Ion's NamibiaSPAN 2D seismic data adjacent to Block 2113A
- Prospect level time/depth structure maps and isochron/isopach maps at key horizons
- Identification of key risk elements (trap, reservoir, seal, source and charge) and risk assessment for leads
- Prospect maps for key exploration leads identified within the 2D seismic survey area
- Volumetric estimates of possible OOIP (Original Oil in Place) or OGIP (Original Gas in Place) for exploration leads
- Integration of Potential Field (gravity and magnetics) data with the seismic interpretation
- Weekly Reports documenting activities and work progress

1.2 Data

The Nabirm 2D seismic survey is located in the southwest portion of Block 2112A, PEL 58 and encompasses approximately a 2275 kilometers^2 (km^2) area (Figure 2). The survey consist of 24 lines including 5 strike lines (oriented parallel to the Namibia coast) and 19 dip lines (oriented perpendicular to the Namibia coast). The longest strike line (Line 1) is 80 kilometers (km) in length; the longest dip line (Line 34) is 40 km in length. The survey area extends from 18 km to 57 km offshore. The 2D seismic grid spacing is 3 km x 4 km with the exception of strike Line 9, which is 7.5 km from strike Line 7. Odd numbered Lines 1, 3, 5, 7 and 9 are oriented parallel to the coastline (strike lines) with Line 1 occurring adjacent to the coast; Line numbers increase moving basinward. Even numbered Lines 2, 4, 6, 8, 10, 12, 14, 16, 18, 20, 22, 24, 26, 28, 30, 32, 34, 36 and 38 are oriented perpendicular to the coastline (dip lines) with Line 2 positioned at the North end of the survey and Line 38 at the South.

The survey was acquired by BGP International using the vessel M/V BGP Pioneer; earlier in 2015 the same vessel completed the Ion Geophysical NamibiaSPAN 2D survey in offshore. The M/V BGP Pioneer acquired 684 line kilometers of 2D seismic data plus shipborne gravity and magnetic data within Block 2113A. The survey was acquired with a single 9 kilometer cable towed 8 meters below the sea surface. Acquisition was completed on 20 March, 2015.

The 2D seismic data were processed by Parallel Geoscience in April and May of 2015. Ion Geophysical was contracted to perform the 2D seismic interpretation and received/loaded the processed 2D dataset into SMT/Kingdom on 6 July, 2015.

Two Ion Geophysical NamibiaSPAN 2D seismic lines are located near the Nabirm 2D seismic survey area. These lines are NAM-3500, located 33 km northwest and NAM-4000, located 6 km southeast (Figure 3).

The nearest well to the Nabirm 2D seismic survey is the Ranger Oil 2213 6-1 well located 33 km southwest of the survey area. The 2213 6-1 well is located on NamibiaSPAN line NAM-4000.

The data has been acquired and processed down to 11 seconds TWT; it is only necessary to display the top 2 seconds for interpretation purposes due to the close proximity of basement to the seafloor. Overall data quality is poor, likely due to acquisition and processing parameters. There is high variability in the quality of adjacent lines. A definitive water bottom reflector is not visible on the data. The data has extensive multiples below the top basement reflector; top basement is readily recognized as the first surface generating multiples.

2 Regional Geology

2.1 Source, Petroleum and Offshore Wells

Offshore Namibia is an oil-prone area with multiple recognized marine and lacustrine source rocks. The stacked distribution of source intervals enhances probability of a working petroleum system. Numerous occurrences of marine and lacustrine-derived petroleum have been documented in the offshore basins of Namibia and South Africa. Gas occurrences are generally the result of high levels of maturity of marine & lacustrine sources due to deep burial, high heat flow and high geothermal gradients. Source rock type, richness, distribution and level of maturity are favorable for the generation and expulsion of significant volumes of oil. Basins in offshore Namibia are similar to other passive-margin basins in the South Atlantic including Brazil, Angola, Gabon, Congo, Equatorial Guinea, Uruguay and Argentina.

Three petroleum source intervals have been identified from offshore wells and DSDP/ ODP sites. The three source intervals are rift (lacustrine), Lower Cretaceous Barremian-Aptian (marine) and Cenomanian-Turonian (marine) sources. Pre-rift (Karoo) source intervals are likely present and may generate gas, yet the offshore data is inadequate to assess their contribution.

2.1.1 Rift Sources

Rift lakes and lacustrine source rocks are observed in all basins in the South Atlantic. Rift sources occur in all rift basins that have been tested by wells. Rift basins have been shown to be major oil sources in the Santos, Campos and Espirito de Santo Basins of Brazil. Rift basins also provide source rocks in the Falklands, Angola and Gabon. Rift penetrations are uncommon in Southwest Africa but several examples include Kudu Field, the A-J1 Well (offshore South Africa) and Falklands basin. Rift basins are commonly observed in offshore Namibia.

2.1.2 Marine Sources

Lower Cretaceous Barremian – Aptian (BA) transgressive marine source rocks are recognized in offshore Namibia. The organic rich marine shales were deposited during initial flooding of South Atlantic and were deposited during greenhouse conditions. The proto-South Atlantic was likely anoxic due to restricted open marine circulation by the Falklands Plateau to the south. This source interval is analogous to early Albian sources north of Walvis Ridge. The BA source interval has been characterized by high levels of maturity where penetrated in offshore Namibia. BA source rocks have been recognized in the HRT Wingat 1 and Murombe 1 wells that are located 100 km basinward from Block 2113A.

Cenomanian – Turonian (CT) source rocks are widely distributed throughout the South Atlantic and are generally anoxic black shales interbedded with lower TOC shales. These sediments were deposited during times of high organic productivity and low circulation or Ocean Anoxic Events (OAE's). CT source rocks have been recognized in wells in offshore Namibia including the Norsk Hydro wells in Block 1911 and the Block 2714 Petrobras Kabeljou 1.

2.1.3 Petroleum Occurrences

Petroleum occurrences in offshore Namibia include oil production or oil shows in 5 offshore Namibia locations. Kudu Field wells tested lacustrine oil and marine condensate; the 1911 10-1 had marine oil shows, the 1911 15-1 had marine oil shows, the 2012 13-1 had marine oil shows and the Wingat 1 well recovered light oil (42º API Gravity).

2.1.4 Nearby Wells and NamibiaSPAN 2D Seismic Data

Two nearby wells reported penetrating high quality source rocks, the Wingat 1 and the Murombe 1 wells, drilled by HRT in 2013 (see Figure 3).

Galp Energia (Partner with HRT, Operator) reported that the Wingat-1 well, drilled in a water depth of 1,005 meters, reached a final depth of 5,000 meters. Information obtained from the well identified two well-developed source rocks …"which are rich in organic carbon and both are within the oil-generating window. Also, the well encountered several thin-bedded-sandy reservoirs that are saturated by oil. Four samples of this oil were collected and the analysis of these samples indicated the presence of light oil, 38º to 42º API, with minimal contamination". The well was plugged and abandoned.

HRT announced that the Murombe-1 exploration well was drilled to a total depth (TD) of 5,729 meters with the objective of penetrating two target reservoirs. The primary target was the Murombe reservoir, a Barremian age turbidite fan system, which from wireline logging confirmed a lack of reservoir quality facies and low porosity. However, a mature Aptian marine source in the "oil window" was encountered above the primary Murombe target confirming the source previously encountered in the Wingat-1 well. The Murombe-1 well was plugged and abandoned.

The Wingat and Murombe wells are located along NamibiaSPAN Line NAM-4000 (see Figure 3). The two source intervals recognized in these wells include the deeper Aptian source and the CT source. Approximately 50 km west of Block 2113A, the interpreted Aptian horizon onlaps basement. The interpreted CT horizon may still be present near Block 2113A, yet proximity of the organic rich interval to terrestrial material at the coastline would oxidize and degrade the source potential.

2.1.5 Tullow, PanContinental and the "Oil Mature Fairway"

Tullow (65% OI), Pancontinental (30%WI) and Paragon (5% WI) currently hold EL 37 which is located to the West and northwest adjacent to PEL 58. Pancontinental is exploring ponded basin floor turbidities, slope fans and channels seen under the company's reconnaissance license. The company believes that EL 0037 is one of the few areas covering an oil generating "sweet spot" where oil prone source rocks are sufficiently buried to generate oil. Pancontinental has interpreted an "Oil Mature Fairway" that extends through EL 0037. The Oil Mature Fairway lies to the eastern side of the axis of the basin and the eastern slope area. Oil migration is interpreted to be predominantly to the East. The area described by Pancontinental as the "Oil Mature Fairway" occurs approximately 60 km from the western boundary of Block 2113A. Hydrocarbons generated within this fairway would be migrating eastward and updip toward Block 2113A (Figure 4).

2.2 The Karoo Supergroup of the Huab Region

The surface geology of the Huab region of northwest Namibia consist of the Proterozoic and Cambrian Swakop Group of the Damara Sequence, which is made up of schist, quartzite, marble and volcanics (Figure 5). North of Block 2113A and just outside Block 2113A to the east are outcrops of Karoo Super Group Sediments. The onshore succession includes several igneous complexes, namely the Etendeka, Brandberg, Messum and Cape Cross, all emplaced at 132 Ma. There are also Damara Granites, dated at 430-560 Ma.

Horsthemke provided a thorough summary of the stratigraphy and facies of the Huab region with his 1991 dissertation. The following summary of his work provides an overview of Karoo sedimentation that is onshore to the east of Block 2113A. Figure 6 is a diagram of the stratigraphy of the Huab Basin after Wanke et al., 2000.

The Karoo succession in the Huab Area provides a record of depositional conditions ranging from glaciation to eolian desert environments. The lithologies of the formations represent time periods and sedimentary environments including glacial clastics of the Permo-Carboniferous Dwyka Formation, fluvial sandstones and carbonaceous shales of the Permian Verbrande Berg Formation, Permian lacustrine, deltaic and fluvial clastics of the Tsarabis Formation, Permian cyclic lacustrine clastics and carbonates of the Huab Formation, Permian lacustrine to deltaic red beds of the Gai-as Formation and Mesozoic alluvial and eolian clastics of the Etjo Sandstone (later authors provide evidence for a Lower Cretaceous age for the Etjo Formation due to facies relationships with the 132 Ma Etendeka volcanics).

Deposition of the Dwyka Formation (the oldest unit of the Karoo Supergroup), was influenced by Permo-Carboniferous glaciation. The basinward prograding ice created a glacier-controlled landscape for later Karoo sedimentation. An east-west trending U-shaped valley and adjoining shallow channels and troughs characterize the relief created by Dwyka glaciation. These depressions are filled with glacial till and periglacial sediments that are preserved as relics with restricted lateral extent. Diamictites demonstrate the influence of glacial outwash, sandstones indicate glacio-fluvial and glacio-deltaic environments and argillaceous rhythmites represent distal deposits in meltwater lakes.

The Verbrande Berg Formation was deposited in a fluvial dominated swamp environment and represents the next stage of Karoo deposition following the Dwyka. Within the Verbrande Berg Formation, individual sandstone bodies occur in successions of argillaceous overbank sediments and represent channel deposits of a meandering fluvial system. The overbank environments are characterized by limnic (lake overturn with outgassing of CO_2) claystones and carbonaceous shales with small coal seams, fossils and sedimentary structures. The sediments of the Verbrande Berg Formation were deposited in shallow open waters, marshy wetlands and woody swamps.

The Tsarabis Formation reflects proximal deposition in a large epeiric sea. Stable hydrologic conditions prevailed after an initial transgression. During Tsarabis deposition, the Huab Basin was divided into a western pelagic to prodeltaic environment, an intermediate deltaic environment and an eastern fluvial environment. As a result, these dominantly clastic deposits are subdivided into silty to argillaceous shales in the western portion of the basin near Block 2113A, arenites of fluvially controlled fan deltas in intermediate areas and coarse sandstones and gravels of a fluvial braided river system in the east.

The succession of Huab Formation sediments exhibits two distinct cycles. At the beginning of each cycle, the sediments display characteristics of a hydrologically closed lacustrine system and carbonate sedimentation. Brief transgressions demonstrate a transition to a more hydrologically open system which became dominated by clastic sedimentation toward the end of each cycle. To the east, the terrestrial environment of the Huab Formation is subdivided into two members, including the lower Probeer Member and the upper Gudaus Member. The Probeer Member consists of ground-water influenced carbonate soils that indicate a semiarid climate, while the deltaic sandstones of the upper Gudaus Member represent stages of high wave energy.

The Gai-as Formation consists of continental red beds that that represent a lacustrine depositional succession. A coarsening and shallowing upward trend is indicated by an upward increase in grain size and characteristic sedimentary structures. Deposition starts with argillaceous pelagic to hemipelagic shales, continues with alternations of prodelta deposits and precipitation from a saline carbonate lake and ends with coarse deposits of a partially vegetated delta plain. In the saline environment of the Gai-as Formation, sediments from four tuffaceous layers have been altered to authigenic analcime and potassium feldspar. Permian sedimentation ended with the deposition of coarse-grained terrestrial red beds deposited under subtropical to arid conditions.

Eolian and alluvial deposits of the Etjo Sandstone Formation represent the Mesozoic stage of sedimentation in the Huab Area. The Etjo Sandstone Formation is divided into the upper eolian Etjo Sandstone and the basal coarse alluvial clastics of the Krone Member. The dip direction of the crossbeds indicates transport from southwest to northeast. The Etjo Sandstone is made up of transverse dunes; to the west near Block 2113A smaller barchanoid dunes with restricted lateral extent indicate higher migration and smaller accumulation rates. This facies relationship has been preserved by basalts of the Etendeka Formation.

2.3 Toscanini 1 Well

The Toscanini 1 well was drilled in 1972, 110 km North of Block 2113. The well penetrated Etendeka volcanics, Lower Cretaceous eolian sandstones of the Etjo Formation, shallow marine and coastal plain sediments of the Karoo Age (Permian) Ecca Group (likely the Verbrande Berg Formation, the Tsarabis Formation and the Huab Formation), Gai As Formation marine carbonates (Permian), chlorite muscovite phyllite schists, polymictic conglomerates, pebbly sandstones, arkose, siltstone, lithic greywacke and dolomite of the Mulden Formation and Toscanini Formation of the Damara Group (Cambrian and Neoproterozoic)(Figure 7).

Due to the stratigraphic relationship of the Etendeka and the Etjo Sandstone, the eolian sands are now considered to be the Twyfelfontein Formation. The 132 Ma age of the Etendeka sheet volcanics and the interfingering nature of the Twyfelfontein eolian sandstones establishes the age of the formation as Valenginian – Hauterivian (Lower Cretaceous). The Toscanini-1 well penetrated 35 m of Twyfelfontein sandstone and 170 m the Ecca Group (Verbrande Berg Formation, the Tsarabis Formation and the Huab Formation) with 120 m carbonaceous shales and 15 m of Artinskian coal.

2.4 EcoAtlantic Activity in the Huab Basin

EcoAtlantic has leased 20,000 km^2 within onshore Blocks 2013B, 2014B & 2114 located in West-Central Namibia adjacent to Nabirm's Block 2113A (see Figure 1). EcoAtlantic's targeted resource is the Karoo coal and shale sequences (Verbrande Berg Formation, the Tsarabis Formation and the Huab Formation) and the resource depth is 700 m to 800 m, consistent with the interpreted depth of possible source rocks within Block 2113A. EcoAtlantic estimates that the shale and coal sequence can be 60m thick and the company has committed to one cored exploration well.

Within the Huab Basin 7 boreholes were drilled from the 1970's through the 1980's. The Toscanini 1 well penetrated a 15m thick coal, the DDH1 well penetrated a 10m thick coal horizon, the DH2 well penetrated a 9m thick coal horizon, the Huab 1-4 well penetrated an 8m thick coal horizon and the Huab 2 penetrated 15.2 m of carbonaceous shale and coal.

EconAtlantic has partnered with Kinley Exploration, a USA based integrated energy consultant. Kinley has extensive experience in unconventional gas exploration and development internationally, and in particular the Karoo coals and shales in Sub-Saharan Africa.

2.5 Karoo Prospectivity in Block 2113A

There is a strong possibility of Karoo sediments offshore in Block 2113A. The Lower Cretaceous Etjo Sandstone, now known as the Twyfelfontein Sandstone, has been mapped extensively onshore and likely extends into the offshore area of Block 2113A. The Twyfelfontein Formation - Verbrande/Tsarabis/Huab Formations would be key reservoir-source rock components of a viable Petroleum System within Block 2113A. Karoo age leads within Block 2113A would be stratigraphic traps around the basement highs. The play idea is based on known geology onshore, yet due to the absence of well penetrations, the offshore play would be high risk. The Twyfelfontein sandstone is interpreted as age equivalent to eolian sandstone reservoirs in Kudu Field (estimated gas reserves at 1.4 Tcf). Grove and Jerrum (2010) indicate that the Twyfelfontein Sandstones have porosities of 20% in outcrop yet can be reduced to 0% porosity as a result of diagenetic effects due contact with and proximity to volcanics.

The Permian Verbrande Berg and Tsarabis Formations have also been mapped in outcrop and contain coals within Huab Area. These Karoo age potential source rocks likely continue offshore into Block 2113A.

The conditions exist for generation of coalbed methane in Block 2113A and adjacent offshore areas. The deepest sediments occurring above basement in Block 2113A are at approximately 800 m (2500 feet). Offshore Namibia is characterized as a Volcanic Margin with high heat flow values and high geothermal gradients. Numerous intrusions within the Huab Region likely occur offshore in Block 2113A and would serve to elevate temperatures locally resulting in higher geothermal gradients. Additionally, deeper burial of Karoo age coals farther offshore of Block 2113A would also elevate geothermal gradients, likely pushing coals to temperatures conducive for gas generation.

3 Seismic Interpretation

3.1 Objectives and Methodology

The objective of the seismic interpretation was to identify key depositional features (reflection types, continuity, terminations, downlap, toplap, onlap), structural features (highs, lows, faults and fault styles including normal, reverse, strike-slip) and anomalous reflection packages. The most significant surface within the dataset is a strong reflector at the top of a thick succession of low frequency reflectors. This succession is interpreted as Basement and ION focused on mapping this surface first.

In the absence of well data within the Nabirm Exploration 2D grid, key regional horizons were identified from one exploration well, the Ranger 2213 6-1.

Utilizing the NamibiaSPAN 2D data, these horizons were correlated into Block 2113A. In addition to these regional horizons, local surfaces were identified from the PEL 58 2D Seismic Survey exploration grid and are described as Surface 1, Surface 2, Surface 3 and Basement. Time structure maps, depth structure maps, isochrons and isopachs have been generated for these key horizons.

3.2 Well Ties

Seven formation tops are recognized in the Ranger 2213 6-1 well including Lower Cretaceous, 2252 meters (m), Post-Rift 1, 2194 m, Post-Rift 2, 1748 m, Cretaceous, 772 m, Lower Paleocene, 668 m, Upper Paleocene, 628 m and Lower Eocene, 520 m. In addition, one key horizon, Cenomanian-Turonian (CT) has been interpreted from wells within the NambiaSpan 2D data set and interpreted near Block 2113A.

No check-shot information or time-depth data were available for the Ranger well, therefore it was necessary to utilize data from the Norsk Hydro 1911 10-1 well, located 350 kilometers (km) northwest and the Petrobras 2714 6-1 well, located 590 km south of 2213 6-1 location (and the Nabirm PEL 58 2D Seismic Survey).

NamibiaSPAN Line NAM-4000 crosses the Ranger 2213 6-1 well location; well formation tops and interpreted horizon surfaces include Basement, Cenomanian-Turonian (CT), Cretaceous, Upper Paleocene and Lower Eocene. These surfaces were interpreted to the easternmost end of NAM-4000 where the approximate location of the horizons may be projected onto the PEL 58 2D seismic survey for a qualitative horizon surface tie.

Figure 8 is a basemap showing the location of lines from the two seismic surveys that were used to tie the Ranger 2213 6-1 well formation tops to seismic line NAM-4000, and NAM-4000 to Line 9 of the Nabirm PEL 58 2D Seismic Survey. Figure 9 is an arbitrary line cross-section (with no seismic) showing NambiaSpan Line 4000 with interpreted horizon surfaces from Well 2213 6-1 formation tops and the projected interpreted horizons relative to interpreted horizons on Nabirm Seismic Survey Line 9.

The regional horizons correlated from surface picks in the Ranger 2213 6-1 well include Water Bottom, Lower Eocene, Upper Paleocene, Lower Paleocene, Cretaceous, CT and Basement. There is no direct tie of these surfaces to the Nabirm PEL 58 2D Seismic Survey area. Based on a projection of the interpreted horizons to the PEL 58 Survey at Line 9, three horizons interpreted in the PEL 58 2D Survey, including Surface 1, Surface 2, and Surface 3 appear to be age equivalent to top Cretaceous and older sediments. The CT horizon from NambiaSpan onlaps or pinchs out before reaching the PEL 58 2D Survey Area. The Basement and Water Bottom horizons from each survey appear to correlate very well.

It is not possible to determine if sediments that onlap basement within the PEL 58 2D Survey Area are Karoo age.

3.3 Seismic Observations

Amplitude balance within the 2D seismic dataset is poor with no consistent response; recognizing anomalous amplitudes is difficult. Because water bottom is not visible there is no clear indication of data polarity; peaks and troughs represent unknown reflection response. Data polarity varies from line to line. Faults have minimal vertical separation yet cause a disruption in downward propagating signal.

A tertiary, cretaceous and possible Karoo sediment wedge occurs between 150 and 300 milliseconds (ms) on the nearshore end of the data (East) and between 750 and 1100 ms on the offshore end of the data (West). The thickness of the sediment wedge ranges from approximately 30 ms to 915 ms.

The Top Basement is a homoclinal surface dipping west with an average dip of less than 1 degree. There are several structural culminations in the southwestern portion of the 2D survey area with two prominent basement structural trends (elongate faulted 3-way and 4-way closures) that extend 10-15 km northwest-southeast (along strike) in the southern half of the survey area.

Numerous reflector terminations onlap the older basement surface, creating possible stratigraphic traps. Stratigraphic terminations indicate the possible development of nearshore bars or strandplains in the shallow section.

Faults exhibit normal throw and become listric with depth. The presences of many faults can create migration pathways and fault traps.

3.4 Representative 2D Seismic Lines

Four representative seismic lines including Line 5 (strike), Line 9 (strike), Line 16(dip) and Line 34 (dip) are shown in Figures 10 – 13. These lines provide examples of seismic data quality and seismic features observed within the 2D Seismic Survey area.

Horizons displayed on the sections include Water Bottom (blue), Surface 1 (purple), Surface 2 (green), Surface 3 (orange), Basement (red) and are discussed further in Section 4.1, Key Horizons.

Faults are black and appear vertical with very small degrees of fault throw or vertical separation.

Nabirm Line 5 (Figure 10) is a strike line located at an intermediate position within the PEL 58 2D Seismic Survey area (see Figure 2). A basement sag or flexure occurs left of the line centerpoint. that is a possible strike-slip fault (into the plane of section). Basement dip is to the Northwest and Karoo, Cretaceous and Tertiary sediments that overlie basement are onlapping to the right (Southeast). Basement multiples proprogate downward throught the section.

Nabirm Line 9 (Figure 11) is a strike line located at the distal, basinward-most position within the Nabirm PEL 58 2D Seismic Survey (see Figure 2). Several basement features occur on the right (Southeast) side of the seismic line. Karoo, Cretaceous and Tertiary sediments that overlie basement are onlapping to the right (Southeast). Basement multiples propagate downward through the section.

Nabirm Line 16 (Figure 12) is a dip line located approximately within the middle of the Nabirm survey (see Figure 2). The line exhibits homoclinal dip toward the Walvis Basin to the West. Possible Karoo, Cretaceous and Tertiary sediments that overlie basement are onlapping to the East. Basement multiples proprogate downward throught the section.

Nabirm Line 34 (Figure 13) is a dip line located in southern survey area (See Figure 2). Notice the homoclinal dip toward the Walvis Basin to the West. Small structural features are present at top Basement from the line centerpoint westward toward the basin. Karoo, Cretaceous and Tertiary sediments that overlie basement are onlapping to the East. Basement multiples proprogate downward throught the section.

4 Mapped Surfaces

4.1 Key Horizons

Key horizons were selected and interpreted based on reflection strength, continuity and their relative position to genetically related successions of sediments. Key horizons include Water Bottom (blue), Surface 1 (purple), Surface 2 (green), Surface 3 (orange) and Basement.

Based on the correlation with the Ranger 2213 6-1 well and the NamibiaSPAN horizons, Surface 1 approximately correlates to top Cretaceous. Surface 2 and Surface 3 are of unknown age, yet based on the NamibiaSPAN horizon interpretation the horizons maybe Campanian, Santonian or Coniacian age. The presence of Karoo age sediments in PEL 58 is hypothesized, yet no direct evidence can be inferred from the 2D seismic data. Karoo age sediments may occur below Surface 3 or may occur as a thin veneer adjacent to basement throughout the survey area.

4.2 Fault Polygons

Faults were picked on all 24 PEL 58 2D Survey lines. The shallow occurrence of sediments above basement, imaging concerns and multiples made picking faults below approximately 1.5 seconds problematic. Faults were picked from the shallowest break of the sediments down to 1.5 seconds. At this shallow depth the faults appear to be vertical and sub-vertical. The 2D grid spacing is 3 km x 4 km. In the case of vertical and near vertical faults, fault intersections (on adjacent strike and dip lines) occur infrequently. Figure 14 is the fault polygon map.

Fault correlations were approximated and corresponding fault polygons were digitized (in map view). The Basement horizon interpretation within the PEL 58 Survey area is the most extensively faulted surface mapped and the fault polygon map represents the top of this horizon.

4.3 Time Structure maps

Five time-structure maps were generated by creating grids from interpreted horizons. The maps include Water Bottom, Surface 1, Surface 2, Surface 3 and Basement (Figures 16 – 21). Hot colors (yellow, orange, red) represent smaller time values (ms) while cool colors (green, light blue, dark blue) represent larger time values (ms).

Figure 15 is the Water Bottom time structure map. Water Bottom extends across the entire survey area. Water bottom was not imaged on the PEL 58 2D Seismic Survey and it was not picked as a seismic surface. These data were acquired as shipborne data during acquisition of the seismic survey. The water bottom depth data has been converted to 2-way time (ms) to create this map.

Figure 16 is the Surface 1 time structure map. Surface 1 is an interpreted seismic surface from the 2D seismic survey area. Like Water Bottom, Surface 1 extends across the entire survey area. The time surface structure of Surface 1 extends from a 2-way time of 240 ms down to 540 ms.

Figure 17 is the Surface 2 time structure map. Surface 2 is an interpreted seismic surface from the 2D seismic survey area. Surface 2 onlaps basement within the PEL 58 2D Seismic Survey area. This onlap is represented by the eastern limit Surface 2 shown in Figure 18. Surface 2 sediments pinch-out at this location and do not extend farther east.

Figure 18 is the Surface 3 time structure map. Surface 3 is an interpreted seismic surface from the 2D seismic survey area. Like Surface 2, Surface 3 onlaps basement within the PEL 2D Seismic Survey area. This onlap is prepresented by the eastern limit of Surface 3 shown in Figure 19. Surface 3 sediments pinch-out at this location and do not extend farther east.

Figure 19 is the Basement time structure map. Basement is an interpreted seismic surface from the 2D seismic survey area. Basement extends across the entire survey area. The Basement surface is exposed 18 km east onshore as surface geology of the Huab region of northwest Namibia. As previously discussed in Regional Geology (Section 2), Basement consists of Proterozoic and Cambrian Swakop Group (Damara Sequence) schist, quartzite, marble and volcanics.

4.4 Isochron Maps

Isochron maps were constructed to illustrated variations in the time thickness of the different interpreted horizons. Isochron maps and their depth equivalent, isopach maps can be used to illustrate subsidence and sediment fill history. The thickness, distribution and implications of the isochron/isopach maps are discussed in section 4.7, Isopach Maps.

The maps were generated by subtracting the time values of shallower horizons from the time values of deeper horizons. Isochron maps were generated for four surfaces including Recent Sediments, Surface 1, Surface 2 and Surface 3 (Figures 21 – 24). Hot colors (yellow, orange, red) represent smaller time values (ms) while cool colors (green, light blue, dark blue) represent larger time values (ms).

Figure 20 is the Recent Sediments Isochron. This isochron map was generated by subtracting Water Bottom Time Structure (ms) from Surface 1 Time Structure (ms). This isochron ranges in thickness from approximately 115 ms in the east, to 350 ms in the west.

Figure 21 is the Surface 1 Isochron Map. This isochron map was generated by subtracting Surface 1 Time Structure (ms) from Surface 2 Time Structure (ms). The surface is thin and ranges from approximately 9 ms in the eastern portion of the survey area to 220 ms in the west.

Figure 22 is the Surface 2 Isochron Map. This isochron map was generated by subtracting Surface 2 Time Structure (ms) from Surface 3 Time Structure (ms). The Surface 2 Isochron map ranges in thickness from 9 ms to 220 ms.

Figure 23 is the Surface 3 Isochron Map. This isochron map was generated by subtracting Surface 3 Time Structure (ms) from Basement Time Structure (ms). The Surface 3 Isochron map ranges in thickness from 9 ms to 225 ms.

4.5 Depth Conversion Methodology

Conversion of time structure maps to depth involved separate calculations for the water column (bathymetry was acquired during seismic acquisition) and the sediments. For each surface including Surface 1, Surface 2, Surface 3 and Basement, the water depth (converted to time) was subtracted. The time surfaces (less water bottom) were then depth converted using a Time-Depth function from the 1911 10-1 well. After each surface was converted to depth, water bottom (in depth) was added to get the final depth structure of each interpreted surface.

4.6 Depth Structure Maps

Five depth structure maps were generated by depth converting time structure grids (created from interpreted horizons). The maps include Water Bottom, Surface 1, Surface 2, Surface 3 and Basement (Figures 24 – 28). Hot colors (yellow, orange, red) represent shallow depths (m) while cool colors (green, light blue, dark blue) represent deeper depths (m).

The Water Bottom depth structure map (Figure 24) was created from shipborne bathymetry data acquired during the acquisition of the PEL 58 2D Seismic Survey. No water bottom reflector was visible on the seismic sections and therefore it not necessary to convert an interpreted water bottom horizon to depth. The water bottom slopes gently toward basin to the west-southwest at an average dip less than 1º.

The Surface 1 depth structure map (Figure 25) exhibits a deepening trend to the Southwest. The surface occurs at approximately 180 m to the west and deepens to more than 400 m in the Southwestern corner of the PEL 58 2D Survey area. From 180 m to 250 m, the surface is rugose and undulating with average dip less than 1º (0.1º). Beyond the 250 m contour, the average slope is still less than 1º (0.3º). Surface 1 continues across the entire survey area and does not onlap basement or pinchout. Small closure(s) are recognized on this surface in the northern survey area, yet are not prospective.

The Surface 2 depth structure map (Figure 26) exhibits a deepening trend to the Southwest (similar to Surface 1). The surface is shallowest in the north survey area (300 m) and is deepest in the Southwest (>525 m). The dip on this surface is not uniform, steepening and flattening at different locations within the survey area. The steepest dips are less than 1º (0.9º). Surface 2 onlaps basement (pinches out) to the east, approximately 5 – 10 km from the eastern edge of the PEL 58 2D Survey area. No significant closures are recognized on Surface 2.

The Surface 3 depth structure map (Figure 27) exhibits a more westerly deepening trend (than Surface 1 and Surface 2). Surface 3 is most shallow to the north (400 m) and deepest to the west and southwest (>675 m). The dip of Surface 3 is not uniform, flattening and steepening at several locations within the survey area. The steepest dips are around 1.5º, but the average dip remains less than 1º. Surface 3 onlaps basement to the east, approximately 15 – 20 km from the eastern edge of PEL 58 2D Survey area. Several small four-way closures occur on this surface but are not prospective.

The Basement depth structure map (Figure 28) exhibits a west-southwesterly deepening trend. The surface is shallowest to the northeast (120 m) and deepest to the southwest (>800 m). The average dip on the basement surface is < 1º. Several structural features have surface dips of 2-3º. Basement continues across the entire PEL 58 2D Survey area, outcropping onshore approximately 20 km east of the survey area. Basement is extensively faulted within the survey area; most faults have little vertical separation and are not significant. Four significant four-way closures are recognized in the southwest part of the survey area. These basement closures have been identified as leads.

4.7 Isopach Maps

Isopach maps are utilized to illustrate subsidence and sediment fill history. Isopach maps were generated by subtracting the depth values of shallower horizons from the depth values of deeper horizons. Isopach maps were generated for four surfaces including Recent Sediments, Surface 1, Surface 2 and Surface 3 (Figures 29 – 32). Two additonal isopachs, Surface 3.5 and Surface 4, were created from the Surface 3 Isopach map. Hot colors (yellow, orange, red) represent thinner depth intervals (m) while cool colors (green, light blue, dark blue) represent thicker sediment intevals (m).

Figure 29 is the Recent Sediments Isopach map. Generally, the Recent Sediments Isopach thickens basinward. The sediments do not thicken uniformly parallel to the Namibia coastline, indicating a more localized basin subsidence history in the south and southwest survey area. This isopach character may also indicate greater sediment supply in the south and southwest survey area with input from a sediment source such as a river mouth with deltaic sediments prograding basinward.

Figure 30 is the Surface 1 Isopach Map. Surface 1 sediments indicate onlap of basement to the east and uniform regional subsidence within the survey area. This isopach character may also be created by an absence of a sediment point source (local sediment supply) and sediments being transported and rework by longshore drift.

Figure 31 is the Surface 2 Isopach Map. Surface 2 Isopach thickening is oriented N-S in the western survey area, suggesting a different subsidence history from Recent Sediments and Surface 1. Localized thickening and thinning indicates sediments continue to fill lows adjacent to basement highs. Sediment supply may have been largely from the east and southeast.

Figure 32 is the Surface 3 Isopach Map. Surface 3 Isopach thickness variations indicate sediment fill around localized basement highs; regional and local basin subsidence history is difficult to assess. The thickening is well developed around several of these recognized basement features.

4.7.1 Additonal Isopach Maps

Due to onlap and the in-fill character (around basement features) of the Surface 3 (and older) sediments, stratigraphic traps may occur within this unit. To illustrate the in-fill nature of the sediments within this depositional cycle, two additional isopachs were created from the Surface 3 Isopach map.

The Surface 3.5 Isopach map (Figure 33) was created by subtracting 25 m from the Surface 3 Isopach to see the character of a thinner, deeper sediment wedge. This sediment wedge onlaps basement approximately 1-2 km basinward (west) of the Surface 3 onlap.

The Surface 4 Isopach map (Figure 34) was created by subtracting 50 m from the Surface 3 Isopach. This sediment wedge onlaps basement approximately 2-10 km basinward (west) of the Surface 3 onlap.

4.7.2 Structural Closure and Stratigraphic traps

In order to approximate a structural surface on the Surface 4 isopach, 50 m was added to the Surface 3 Structure Map (the Surface 4 Isopach Map is 50 m deeper than the Surface 3 Isopach) to create a Surface 4 Structure Map that corresponds to the Surface 4 Isopach (Figure 35).

Two areas within the PEL 58 2D Survey area may be stratigraphically trapped at this level (Figure 36). In the east central survey area, a closing structural contour of -545 m on the Surface 4 Structure Map would create a stratigraphic trap on the Surface 4 Isopach Map, with an updip sediment wedge that onlaps basement. The PEL 58 2D Seismic data ends on the northeast side of this possible stratigraphic trap. The incomplete data set at this location suggests the feature may not seal, and therefore is not be a viable lead.

A second, large stratigraphically trapped sediment wedge is recognized on Figure 36, with a closing contour of -570 m on the Surface 4 Structure Map. The data from the Surface 4 Structure and Isopach maps indicates this feature is a viable lead.

Figure 37 shows the two stratigraphic traps on the Surface 4 Structure Map. Figure 38 is an isopach map of the Surface 4 stratigraphic traps.

5 Potential Fields Interpretation (Gravity & Magnetics)

Accel Services of Houston, Texas utilized shipborne gravity and magnetic data integrating the potential field data with the seismic interpretation. Gravity and magnetic modeling was done to validate the basement interpretation from the Seismic data. Four 2-1/2 dimensional models were built along two strike lines (Figures 39 and 40) and two dip lines (Figures 41 and 42). These models showed that no significant changes needed to be made to the seismically interpreted basement surface.

The models show density and susceptibility of continental crustal rocks in the basement, which are likely intruded by igneous material in places. There is a large variability in susceptibility of these types of rocks, so the magnetic models alone are not completely definitive regarding lithology, but a viable interpretation of these models is geologically reasonable. There are significant, non-two dimensional features in both the gravity and magnetic data, which have been accommodated in the modeling.
No effort was made to model any features in the sedimentary section in detail, only the basement was considered for this work.

6 Hydrocarbon Prospectivity - Block 2113A Leads

6.1 Leads vs. Prospects

A prospect is defined as potential accumulation of hydrocarbons that is sufficiently well defined to represent a viable drilling target. A lead is a potential area where one or more hydrocarbon accumulations are currently poorly defined and require more data acquisition and/or evaluation in order to be classified as a prospect.

The geologic features identified within Block 2113A must be better defined with more geologic and geophysical data before being drilled. Therefore, the features identified are characterized as leads.

6.2 Identified Leads

Six leads have been identified within the 2D seismic survey area of Block 2113A. There are four structural leads, one stratigraphic lead and one possible amplitude anomaly lead, also stratigraphically trapped. Figure 43 shows the location of the six leads within the PEL 58 2D Seismic Survey area.

6.3 Structural Closure Leads

The structural leads are prominent four-way closures that may be unfaulted or faulted. These features occur within the basement section, at the top of basement underlying the onlapping Tertiary, Cretaceous and possible Karoo sediments. The four leads considered most prospective were chosen based on a minimum size of 4 $km^{2,}$ approximately 1000 acres.

Lead 1 (Figures 44 and 45) is a prominent structural feature on the basement surface, approximately 4 km across at its widest point. The structure is faulted, yet vertical separation along the fault is minimal. The closing contour occurs at approximately -490 m subsea (SS); column height is 70 m. The area of closure on the feature is 1858 acres (7.52 km^2) (Figure 45, Strike Line 9).

Lead 2 (Figures 44 and 45) is a broad structural feature on basement, approximately 7.5 km in length and 2.5 km in width, with 4 low-relief culminations. This feature does not appear to be faulted. The closing contour occurs at -550 m SS; column height is 35-40 m. The area of closure is 2689 acres (10.89 km^2) (Figure 45, Strike Line 9).

Lead 3 (Figures 44 and 46) is a faulted four-way culmination on the basement surface, located west of Lead 2. The feature is approximately 3.5 km in length and 2.5 km in width. The structure is faulted, but vertical separation is small. Closure occurs at -550 m SS and column height is 45-50 m. The closure area is 1292 acres (5.23 km^2) (Figure 46, Dip Line 30).

Lead 4 (Figures 44 and 47) is a four-way culmination on basement, located northwest of Lead 2. The feature is approximately 3.5 km in length and 1.5 km in width. The structure is unfaulted and the closing contour occurs at -570 m; column height is approximately 50 m. Closure area for this feature is 982 acres (3.98 km2) (Figure 47, Dip Line 26).

6.4 Stratigraphic Lead

A stratigraphic lead, Lead 5, is present where the Cretaceous, Tertiary or Karoo age sediments thin and onlap basement and is structurally closed by the overlying structural surface. The lead is recognized due to onlap and the in-fill character of Surface 4 sediments around basement features (see Section 4.71). The prospective sediment wedge onlaps basement approximately 2-10 km basinward (west) of the Surface 3 onlap and pinchout.

Lead 5 is a large stratigraphic feature located east and north of Leads 2 and 4 (Figure 43). The feature is 18 km in length and 7 km in width. The feature is unfaulted and the closing contour occurs at -570 m SS (see Figure 36, Surface 4 Isopach Map). Column height is 50m and closure area is 14,713 acres (59.6 km^2) (Figure 48 and Figure 49, Dip Line 26).

6.5 Amplitude Anomaly Lead

Amplitude balance within the Nabirm 2D seismic dataset is poor with no consistent response. An Automatic Gain Control (AGC) operator was applied to the processed data in order to balance amplitude response sufficiently to map reflections. Water bottom is not visible and there is no indication of data polarity, so seismic peaks and troughs represent unknown acoustic impedance.

Lead 6 is an anomalous amplitude that is recognized in the southernmost 2D survey area (Figure 50). Dip Line 36 (Figure 51) shows this anomalous amplitude feature. The anomalous event occurs within a succession of onlapping reflectors that terminate or pinchout against the basement surface (see Figure 51, SP 4000, Line 35). The event is a weak peak over a strong trough. If data polarity were SEG normal (zero phase), the peak would represent an increase in acoustic impedance or a positive reflection coefficient (hard lithology response). The actual data polarity was not provided, however, therefore the feature has been identified as an anomalous seismic amplitude that occurs in a structural and stratigraphic position favorable for stratigraphic trapping of hydrocarbons.

Lead 6 (Figures 50 and 51) is 10 km in length and 8 km in width. The feature appears unfaulted. There does not appear to be a consistent downdip limit which corresponds to a closing structural contour. Column height is approximately 100 m and closure area is 15,314 acres (62 km^2).

7 Risk Assessment

7.1 Methodology

Exploration risk is determined by assessment of prospect specific risk elements including trap, reservoir, seal and source (hydrocarbon charge). The probability of each risk element has been assessed individually.

7.1.1 Probability

The probability of geologic success (Pg) is a value that is based on objective knowledge, historical data, extrapolations and subjective judgements of geological information. The Pg will vary from prospect to prospect, and is defined as the product of the component probabilities of geological risk elements. As mentioned above, the four risk elements are trap, reservoir, seal and source. The risk element probabilities are estimated with respect to presence and effectiveness and then multiplied to get prospect risk, known as Pg.

Data control is crucial for the establishing reliable geological models for prospects and is a critical parameter for performing risk assessment. Table 1 provides guidelines for assigning prospect risk based on available data, existing analogs and proven models.

Pg	Available Data	Analogs or Models	Proven Models
1.0	Absolute Certainty; Data quality and control excellent.	Only possible models applicable; Unfavorable models impossible.	Identical geologic information found immediately adjacent to area; Verified by excellent well and seismic.
0.9		The model is likely an absolute certainty; Unfavorable models impossible.	
0.8	Condition is probable; data quality and control good; Most likely interpretation.	Model is very likely; Only minor chance that unfavorable model can occur.	Similar geological factor successfully tested by wells in the trend. Lateral continuity is probable as indicated by good well and seismic control.
0.7		Model is likely to very likely; Unfavorable models can be applied.	
0.6	Condition is probable or data control and quality fair; Favorable interpretation.	The model is more likely than all other unfavorable models.	Similar geological factor is known to exist within the trend; Lateral continuity is probable as indicated by limited well and seismic data.
0.5		Likely model, however, unfavorable are also likely.	
0.4	Condition is possible or data control and quality poor to fair; Less favorable interpretation possible.	Unfavorable models are more likely than applied model.	Similar geological factor may exist within the trend; Valid concepts, but poor data indicates possible presence of the feature.
0.3		The model is questionable; unfavorable models are likely to very likely.	
0.2	Condition is virtually to absolutely impossible; Data control and quality excellent	The model is unlikely and very questionable. Unfavorable models are very likely.	The geological factor is not known to exist within the trend; Conditions are verified by well and seismic control.
0.1		The model is unlikely and highly questionable. Unfavorable models are very likely to certain.	

Table 1. Qualitative description of relative probability scale of risk elements including Trap, Reservoir, Seal and Source (modified from CCOP 2004).

7.1.2 Trap

The trap is the stratigraphic or structural feature that ensures the juxtaposition of reservoir and seal such that hydrocarbons remain trapped in the subsurface.

The traps identified within PEL 58 include both structural and stratigraphic types. There are four leads with structural traps; Leads 2 and 4 are four-way dip closures while leads 1 and 3 are faulted four-way closures (see Figure 44). The structural features exist in both time and depth and the certainty of occurrence is high. The estimated Pg for the structural features is 0.9.

There are two stratigraphic traps identified within PEL 58, Lead 5 and an amplitude feature, Lead 6 (that is likely stratigraphically trapped).

Lead 5 may occur within the area identified, yet data quality is poor to fair. The actual integrity of the trapping geometry is postulated, yet occurs in an updip and thinning succession of sediments where the stratigraphic unit thins and pinches out (see Figure 49). The estimated Pg of Trap for Lead 5 is 0.5.

Lead 6 is an anomalous amplitude feature with its eastern edge also occurring in an updip and thinning succession of sediments where the stratigraphic unit thins and pinches out (see Figure 51). The estimated Pg of Trap for Lead 6 is 0.5.

7.1.3 Reservoir

The reservoir is a porous and permeable lithological unit that holds hydrocarbons. Analysis of reservoirs requires an assessment of their occurrence, distribution, porosity and their permeability. Since no direct analogs are available within PEL 58 it is necessary to look to the nearest occurrence(s) of outcrops or wells that may be postulated analogs.

Possible reservoir analogs occur within the onshore area of PEL 58. These analogs are the Lower Cretaceous Twyfelfontain eolian sandstones. Reservoir quality is unknown; Grove and Jerrum (2010) observed 20% porosities in outcrop within the Huab Basin onshore. Adjacent wells including the Murombe 1, Wingat 1 and Ranger 2213 6-1 penetrated some Cretaceous age coarse clastics, yet limited reservoir sands. The Ranger well reported gravels, conglomerates, sandstones, claystones and granite wash; no porosity or permeability information is available. The reference wells mentioned above did not penetrate basement.

Probable Cretaceous and Tertiary reservoir sediments deposited within PEL 58 are nearshore marine barrier bars, strandplains and deltaic sediments. The distribution, quality and presence of these potential reservoirs sands is unknown.

Leads 1 – 4 are structural leads that occur at the top of basement, therefore Cretaceous and Tertiary shallow marine clastic reservoirs are unlikey to occur below this surface and be structurally trapped. Fractured basement and granite wash (eroded basement sediments) are probable reservoirs that occur within the sediment succession prior to deposition of possible Karoo and younger sediments. The estimated Pg of Reservoir for Leads 1 - 4 is 0.4.

The reservoir intervals of Leads 5 and 6 occur within the Cretaceous and Tertiary sediments of Block 58. Lead 5 occurs at the base of the stratigraphic succession that onlaps basement and may have Lower Cretaceous eolian sandstones as seen onshore in the Huab Basin (Twyfelfontein Formation). The estimated Pg of Reservoir for Lead 5 is 0.6.

Lead 6 is an anomalous seismic amplitude event; its extent has been determined by the mapped and projected occurrence of the anomaly on the PEL 58 2D Survey data. An anomalous seismic response is usually indicative of lithology and/or fluid type. Where data polarity is known the presence of anomaly may be used to increase or reduce reservoir quality Pg.

Lead 6 occurs higher within the Cretaceous and Tertiary sediment succession within Block 58; it may be a hydrocarbon charged nearshore marine sandstone unrecognized in offset wells or unpenetrated within the block. The estimated Pg of Reservoir for Lead 6 is 0.6.

7.1.4 Seal

The seal is a low permeability unit that impedes the escape of hydrocarbons from the reservoir rock. Seals include shales, evaporites and other impermeable rocks. Quantitative analysis of seals involves assessment of their thickness and extent; no seal assessment has been conducted in Block 58 due to an absence data.

The sediments that overlie Leads 1-4 onlap from the basin (west) to the basin margin (east). The parallel continuous character of the seismic reflectors indicates marine deposition. These sediments probably include highstand shales deposited as the basin filled and basin margin was transgressed. Because the leads are four-way structural closures, a top seal is necessary while a lateral seal is not.

Leads 2 and 4 are unfaulted four-way closures. The estimated Pg of Seal for Leads 2 and 4 is 0.7. Leads 1 and 3 are faulted four-way closures. The faulting across the four-way closures increases the likelihood of seal failure. The estimated Pg of Seal for Leads 1 and 3 is 0.5.

Leads 5 and 6 are stratigraphic leads; both top and lateral seals are critical for entrapment. These two leads are unfaulted features and the updip pinchout is recognizable on seismic. The estimated Pg of Seal for stratigraphic Leads 5 and 6 is 0.6.

7.1.5 Source (Presence/Generation/Migration)

Source rocks are organic rich sediments containing organic matter capable of generating hydrocarbons. The presence of source rock depends on local stratigraphy, paleogeography and sedimentology; source rocks are deposited under unique conditions. Upwelling of cold, oxygen poor currents, restricted marine conditions and restricted lacustrine environments may all result in deposition and preservation of organic matter.

Oil generation generally occurs from 60° to 120°C; gas generation continues up to 200°C. In order to determine the likelihood of oil or gas generation, the thermal history of the source rock must be calculated. This is performed with a geochemical analysis of the source rock and basin modelling.

Hydrocarbons move to reservoirs along migration pathways. These pathways may be faults (migration across stratigraphic layers) or interstratal (migration along stratigraphic layers - within sands or along unconformities).

7.1.5.1 Source Presence

No marine our lacustrine source rocks have been identified in Block 58. East of Block 58 within the Huab Basin, the Permian Ecca Group (Verbrande Berg Formation, Tsarabis Formation and Huab Formation) has documented coal deposits in outcrop. The Toscanini 1 well, 110 km north of Block 58, found 120 m carbonaceous shales and 15m of Artinskian coal within the Ecca Group.

Barremian–Aptian (BA) transgressive marine source rocks are recognized in offshore Namibia. The organic rich BA marine shales were deposited during initial flooding of South Atlantic and were deposited during greenhouse conditions. BA source rocks have been recognized in the HRT Wingat 1 and Murombe 1 wells ~100 km basinward from Block 2113A. The quality of the source intervals identified in these wells is unknown; Tower Resources reported on their website that an "announcement dated 22 May 2013 from HRT Participações em Petróleo S.A. stated that the Wingat 1 well recovered four 450 cl samples of light 38 to 42 degree API oil from thin sands of undisclosed age. It drilled through two 'well-developed source rocks, which are rich in organic carbon and are within the oil-generating window'". This source interval onlaps basement (on 2D seismic from NamibiaSPAN) approximately 60 km west of PEL 58 and does not extend into the block.

Cenomanian – Turonian (CT) source rocks are widely distributed throughout the South Atlantic and are generally anoxic black shales. These sediments were deposited during times of high organic productivity and low circulation. CT source rocks have been recognized in the Norsk Hydro wells in Block 1911 and the Block 2714 Petrobras Kabeljou 1. The NamibiaSPAN preliminary mapped CT horizon onlaps basement several kilometers basinward (west) of PEL 58 and does not extend into the block.

7.1.5.2 Source Maturity

The deepest sediments within PEL 58 that occur above basement are at approximately 800 m (2500 feet). Using an estimated geothermal gradient of 25ºC/km, deltaT is 20ºC. With a surface temperature of 30ºC, the estimated temperature at an 800 m sediment depth would be 55ºC. This is above the 60ºC temperature needed to initiate the thermal maturation process of the source interval (oil generation occurs from 60° to 120°C). Higher temperatures occur with deeper burial and as mentioned above, marine source intervals are known to occur farther offshore and may be mature and generating hydrocarbons.

The factors that influence the distance hydrocarbons can migrate are complexly interrelated. The dominant factors controlling long distance hydrocarbon migration include volume of generated hydrocarbons, efficient expulsion, high-quality carrier beds, uninterrupted up-dip pathways and a high-quality regional seal. The conditions controlling long distance migration may be satisfied within the Walvis Basin and its adjacent margin resulting in hydrocarbon migration into PEL 58.

Generation of coalbed methane in PEL 58 and adjacent offshore areas is possible. Offshore Namibia is characterized as a volcanic margin with high heat flow values and high geothermal gradients. Numerous intrusions within the Huab Region likely occur offshore in PEL 58 and would serve to elevate temperatures locally resulting in higher geothermal gradients. Additionally, deeper burial of Karoo Age coals farther offshore of PEL 58 would also elevate geothermal gradients, likely pushing coals to temperatures conducive for gas generation.

7.1.5.3 Migration Pathways

The interpreted Basement is extensively faulted, yet only a few faults continue into the Cretaceous and Tertiary sediment wedge. These faults could serve as migration pathways from source intervals occurring offshore and basinward of PEL 58 (within the Cretacous section). Long distance migration may allow the hydrocarbons to migrate along unconformities or well-developed highstand marine shales (high-quality regional seals) and then up through the section (along faults) and into younger reservoirs.

Leads 1 – 4 are structural features at the top of basement. These features occur structurally higher, yet stratigrapically lower (older) than possible offshore marine source intervals. Because of this juxtaposition, younger, deeper mature source intervals may possibly charge the older, shallower basement features (with ideal generation, migration and trap timing).

An additional possible source, Karoo age coals, may be present, yet would require even higher temperatures than kerogen (organic matter found in source rocks) to generate gas (100°C and higher). These Karoo coals would have to occur much farther offshore to be mature (deeper burial), relying on long distance migration to charge PEL 58 reservoirs.

The limited information and risk associated with Source (presence/maturity/migration) makes the Pg of Source for Leads 1 - 4 0.4.

Leads 5 and 6 are stratigraphically trapped in the updip position, yet open downdip. If a source interval basinward (west) is generating hydrocabons, these reservoirs could be charged. The probability of Source (presence/maturity/migration) for Leads 5 and 6 is 0.5.

7.2 Pg Summary

	Trap Pg	Reservoir Pg	Seal Pg	Source Pg	Lead Pg
Lead 1	0.9	0.4	0.5	0.4	0.072
Lead 2	0.9	0.4	0.7	0.4	0.10
Lead 3	0.9	0.4	0.5	0.4	0.072
Lead 4	0.9	0.4	0.7	0.4	0.10
Lead 5	0.5	0.6	0.6	0.5	0.09
Lead 6	0.5	0.6	0.6	0.5	0.09

Table 2. Individual risk element Pg values for PEL 58 leads and Pg summary.

8 Volumetric Estimation

8.1 Methodology

8.1.1 Lognormal Distribution

The statistical distribution used to describe independent variables in nature is the lognormal distribution. This type of distribution with the mode (most likely value) skewed to the left is frequently observed in nature. The origin of this distribution comes from the "central limit theorem" which indicates that a log normal distribution always results when the observed quantity is the product of two or more independent distributions. Because geologic parameters used to determine hydrocarbon resource numbers (area, net pay thickness, porosity, hydrocarbon saturation, formation volume factor and recovery factor) are independent, a lognormal distribution best characterizes each of these parameters.

8.1.2 Monte Carlo Simulation

The Monte Carlo procedure utilizes independent cumulative probability distributions (of geologic parameters) to arrive at a prospect resource estimate. This approach is more robust than using a deterministic approach (that involves multiplying the best estimate for each geologic parameter to obtain a single resource value) because other conditions are recognized including upside, downside, most likely and mean resource values.

8.2 Reserves and Resources

8.2.1 Definition of Reserves

The Society of Petroleum Engineers (SPE) define Reserves as "those quantities of petroleum claimed to be commercially recoverable by application of development projects to known accumulations under defined conditions." Petroleum quantities must fit four criteria to be classified as Reserves. They must be (1) discovered through one or more exploratory wells, (2) recoverable using existing technology, (3) commercially viable, and (4) remain in the ground.

There are three classifications for reserves: proved, probable and possible. Proved Reserves are those with a "reasonable certainty" (a minimum 90% confidence) of being recoverable under existing economic and political conditions. Probable Reserves are hydrocarbon quantities with a 50% confidence level of recovery. Possible Reserves are hydrocarbon quantities with a minimum 10% confidence level of recovery.

8.2.2 Definition of Resources

SPE defines two categories of Resources: contingent and prospective. Contingent Resources are quantities of hydrocarbons estimated, as of a given date, to be potentially recoverable from known accumulations, but the projects are not yet considered mature enough for commercial development due to one or more contingencies. Prospective Resources are quantities of hydrocarbons estimated to be potentially recoverable from undiscovered accumulations by application of future development projects.

The identified leads within PEL 58 are immature and not ready for commercial development; the hydrocarbons are potentially recoverable from undiscovered accumulations and are characterized as Prospective Resources.

8.3 PEL 58 Lead Geologic Parameters

Geologic parameters used to determine hydrocarbon resources for the Block 2113A leads include area (acres), net pay thickness (feet), porosity (fraction), hydrocarbon saturation (1-Sw, fraction), formation volume factor (rcf/scf) and recovery factor (fraction).

There are no discoveries or production within the prospective stratigraphic intervals of Block 2113A or adjacent areas to apply as analogs. The nearest non-commercial discovery is at the Wingat 1 well, 100 km west; reported reservoir intervals penetrated (Aptian?) onlap west of Block 2113A. The Ranger 2213 6-1 well is located 35 km southwest has cuttings and core descriptions, but no quantitative geologic information is available. The Toscanini 1 well is located 110 km North of Block 2113A has lithologic descriptions, but no quantitative geologic information is available.

8.3.1 Area

Area has been measured directly in SMT/Kingdom by digitizing the lowest closing contour of the structural and stratigraphic features. This deterministic value has been used as a guide for creating a lognormal distribution of possible outcomes of reservoir area (P10, P90, Pmean). The lead areas are show in Table 3.

Nabirm Leads	Lead Area (Acres)
Structural Lead 1	1858
Structural Lead 2	2689
Structural Lead 3	1292
Structural Lead 4	982
Stratigraphic Lead 5	14713
Amplitude Lead 6	15314

Table 3. Nabirm Lead Areas.

8.3.2 Net Pay Thickness

The net pay thickness represents the thickness of porous reservoir within the gross reservoir interval. Column height was assumed to be maximum reservoir thickness and net pay thickness was estimated by assuming a .30 net to gross ratio.

8.3.3 Porosity

Porosity has been estimated based on predicted depositional models and sediment age. Within leads 1 – 4, reservoir occurs below or just above the basement surface. Fractured crystalline basement or granite would likely have low porosities; overlying possible Karoo age sediments (Twyfelfontein Eolian Sandstone) have maximum porosities of 20%.

Leads 5 and 6 occur within the overlying Tertiary, Cretaceous or possible Karoo age sediments. Minimal porosity loss is postulated with shallow burial and younger geologic age sediments (due to compaction and diagenesis). Cumulative probabilities include porosities that are predicted to be as high as 32%.

8.3.4 Hydrocarbon Saturation (So, Sg)

The range of hydrocarbon saturation values (Sg) have been estimated based on experience in reservoirs of similar depth and age. Separate hydrocarbon saturation probability distributions values have been generated for each lead.

8.3.5 Formation Volume Factor (Bo, Bg)

FVF has been calculated based on pressure and depth; since the prospective reservoir intervals are very shallow, the FVF's values are low. Separate oil and gas probability distributions of FVF values have been generated for each lead.

8.3.6 Recovery Factor (RF)

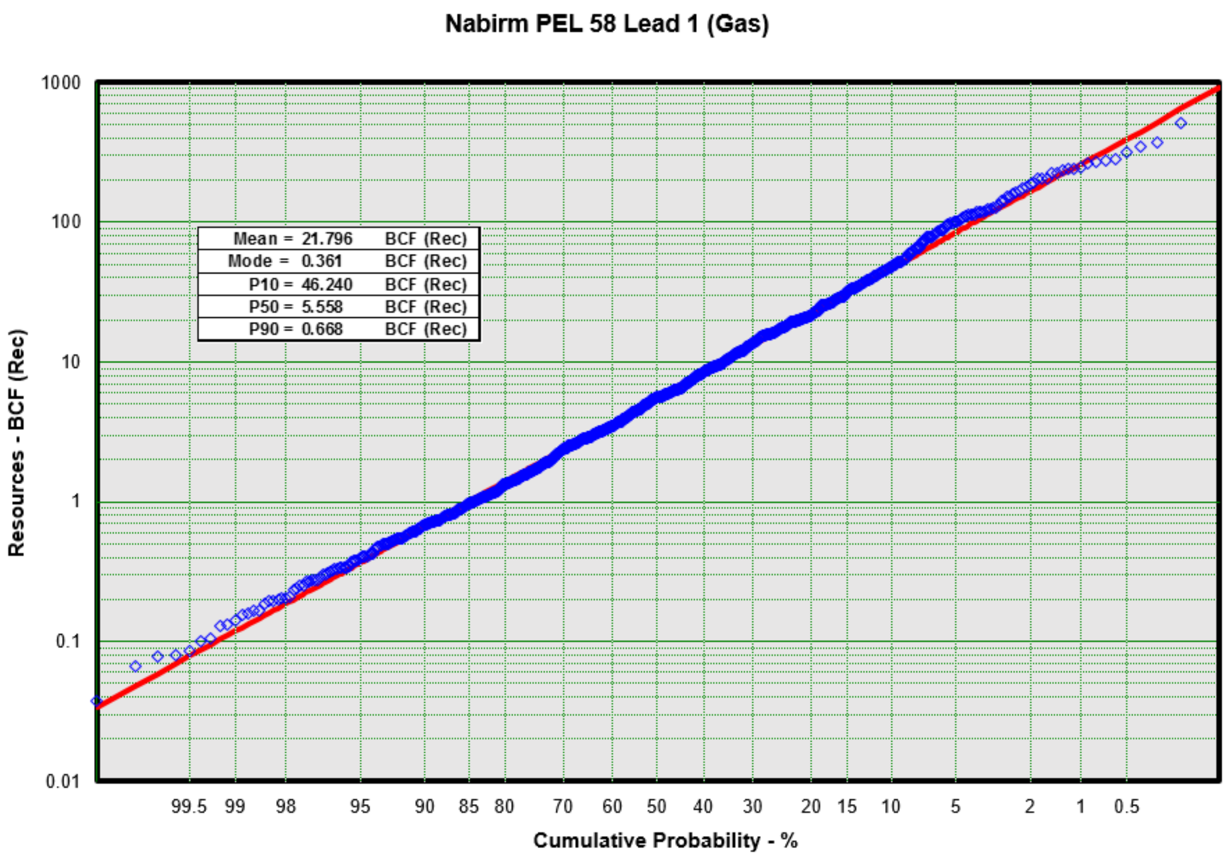
Gas reservoirs are known to have higher recovery factors (RF), typically 50% - 80%; oil reservoirs typically have RF values ranging from 10 – 35%. Separate oil and gas probability distributions of RF values have been generated for each lead.

8.4 PEL 58 Lead Parameter Distributions and Volumetrics

Lead 1 Parameter Probability Distributions (Gas)

Area (Acres)	Net Pay (feet)	Porosity	Sg	Bg	RF(gas)
Mean = 1,648.9	Mean = 70.0	Mean = 0.13	Mean = 0.76	Mean = 0.0176	Mean = 0.72
Mode = 69.9	Mode = 41.9	Mode = 0.11	Mode = 0.73	Mode = 0.0175	Mode = 0.67
P90 = 89.5	P90 = 27.9	P90 = 0.08	P90 = 0.61	P90 = 0.0169	P90 = 0.53
P50 = 575.0	P50 = 59.0	P50 = 0.13	P50 = 0.75	P50 = 0.0176	P50 = 0.70
P10 = 3,694.5	P10 = 124.8	P10 = 0.20	P10 = 0.92	P10 = 0.0183	P10 = 0.93

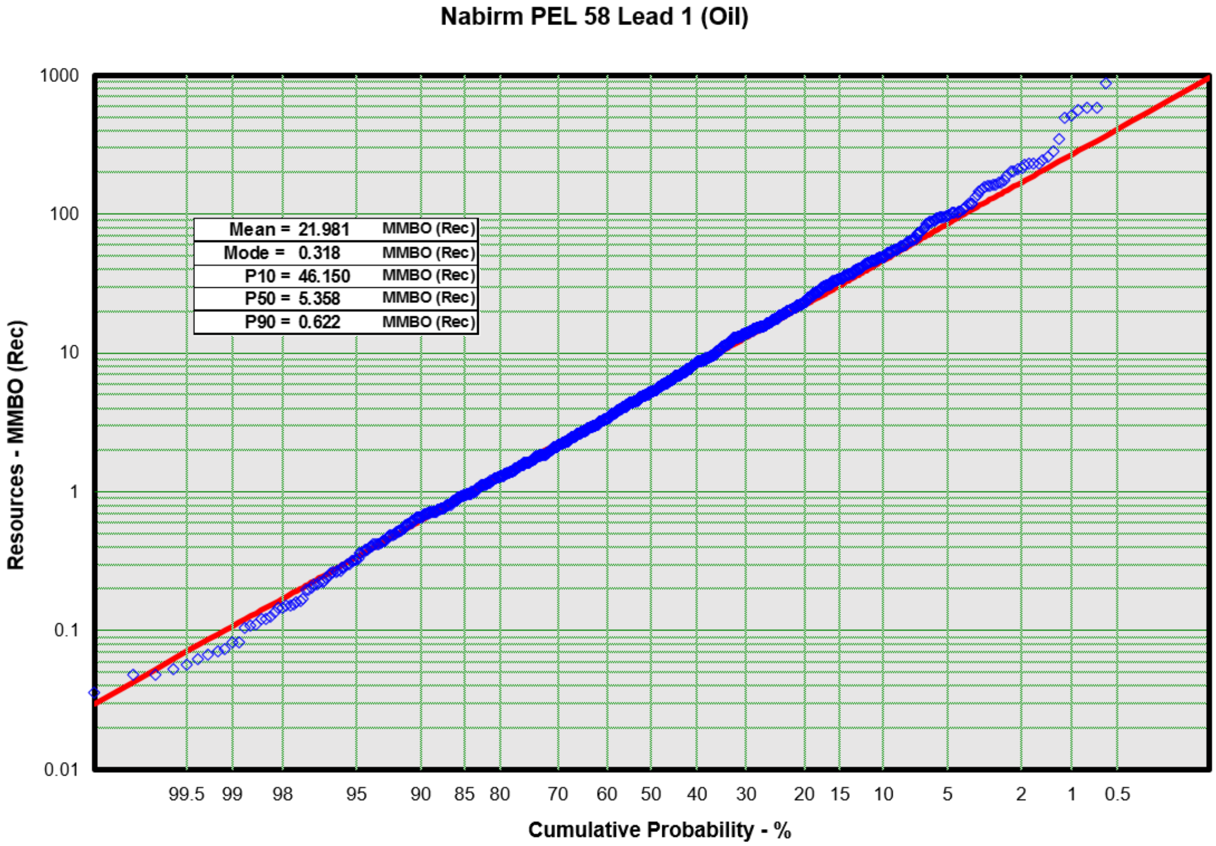
Lead 1 Volumetrics (Gas)



Lead 1 Parameter Probability Distributions (Oil)

Area (Acres)	Net Pay (feet)	Porosity	So	Bo	RF(oil)
Mean = 1,648.9	Mean = 70.0	Mean = 0.13	Mean = 0.76	Mean = 1.07	Mean = 0.25
Mode = 69.9	Mode = 41.9	Mode = 0.11	Mode = 0.73	Mode = 1.07	Mode = 0.15
P90 = 89.5	P90 = 27.9	P90 = 0.08	P90 = 0.61	P90 = 1.05	P90 = 0.10
P50 = 575.0	P50 = 59.0	P50 = 0.13	P50 = 0.75	P50 = 1.07	P50 = 0.21
P10 = 3,694.5	P10 = 124.8	P10 = 0.20	P10 = 0.92	P10 = 1.10	P10 = 0.44

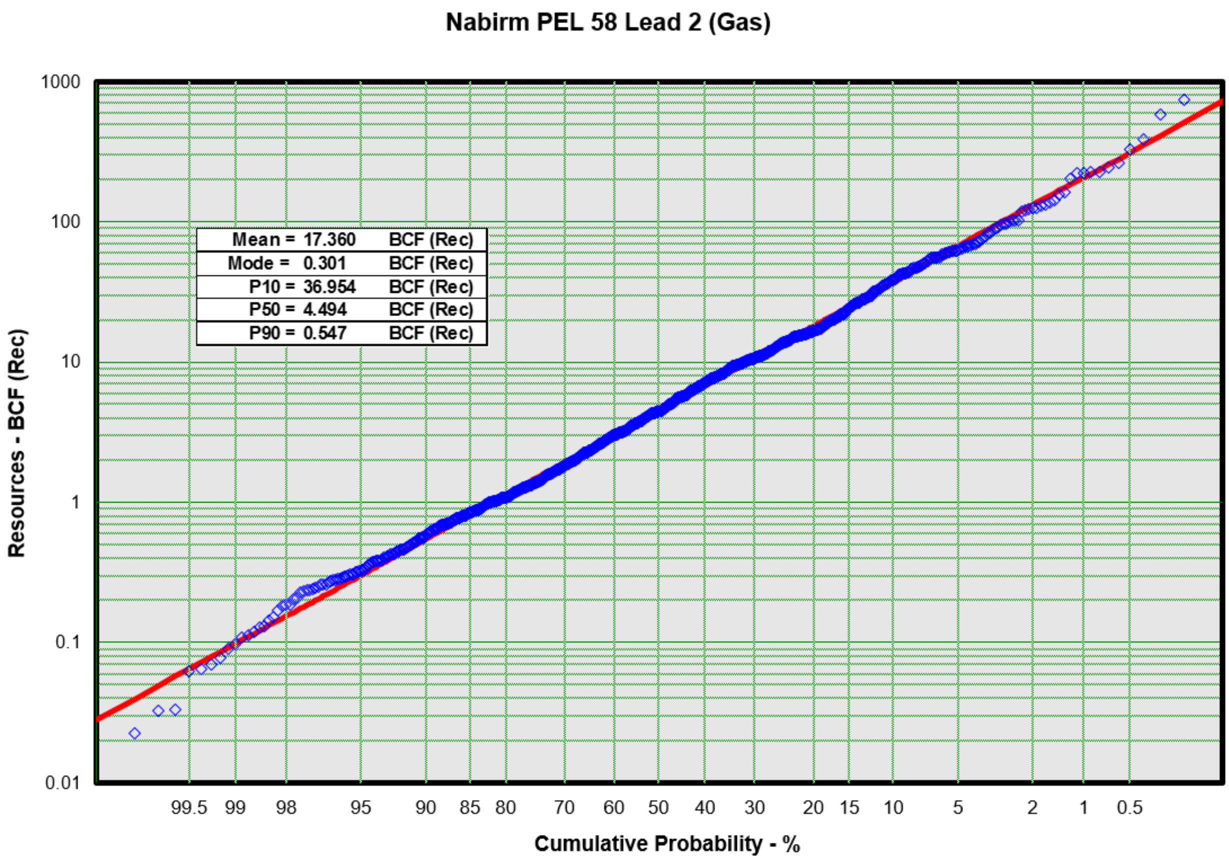
Lead 1 Volumetrics (Oil)



Lead 2 Parameter Probability Distributions (Gas)

Area (Acres)	Net Pay (feet)	Porosity	Sg	Bg	RF(gas)
Mean = 2,317.9	Mean = 39.7	Mean = 0.13	Mean = 0.76	Mean = 0.0176	Mean = 0.72
Mode = 110.3	Mode = 22.4	Mode = 0.11	Mode = 0.73	Mode = 0.0175	Mode = 0.67
P90 = 135.3	P90 = 14.9	P90 = 0.08	P90 = 0.61	P90 = 0.0169	P90 = 0.53
P50 = 840.0	P50 = 32.8	P50 = 0.13	P50 = 0.75	P50 = 0.0176	P50 = 0.70
P10 = 5,215.2	P10 = 72.3	P10 = 0.20	P10 = 0.92	P10 = 0.0183	P10 = 0.93

Lead 2 Volumetrics (Gas)



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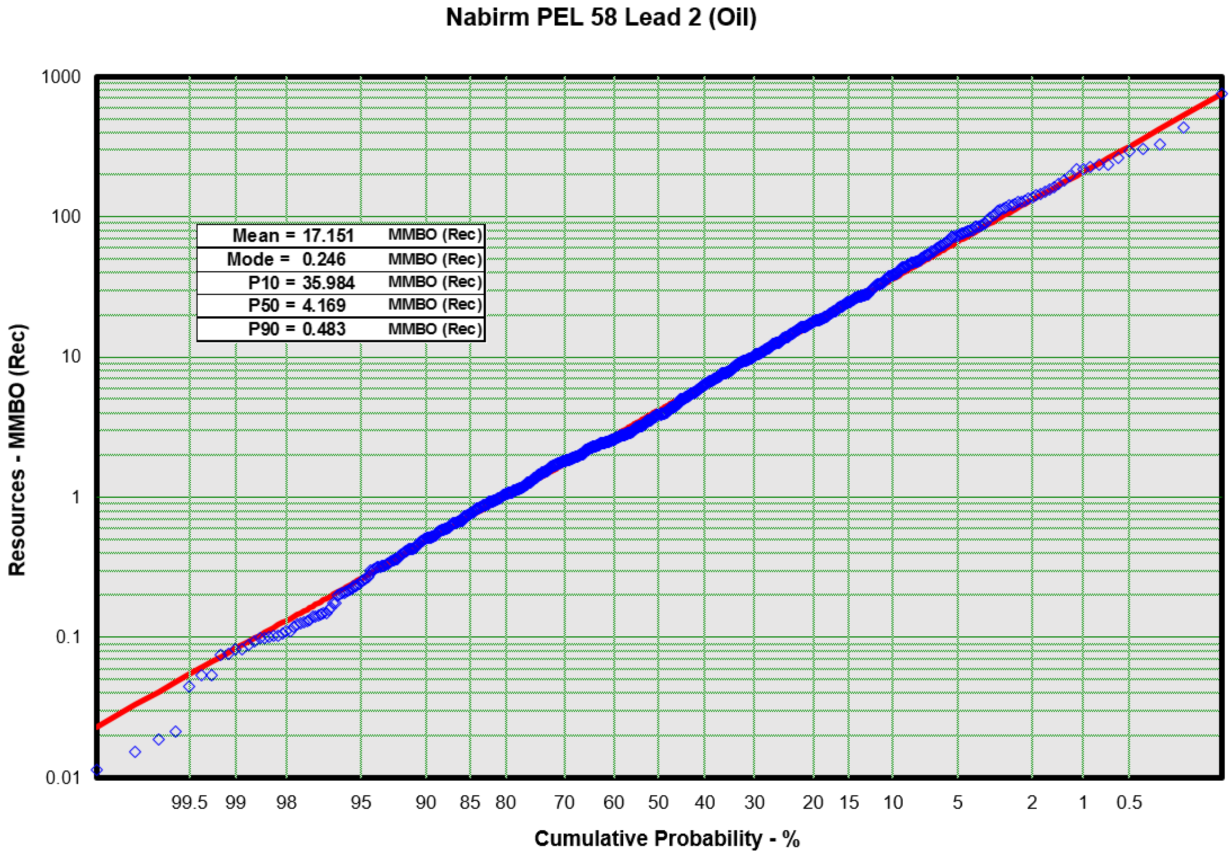
Lead 2 Parameter Probability Distributions (Oil)

Area (Acres)	Net Pay (feet)	Porosity	So	Bo	RF(oil)
Mean = 2,322.5	Mean = 39.7	Mean = 0.13	Mean = 0.76	Mean = 1.07	Mean = 0.250
Mode = 109.9	Mode = 22.4	Mode = 0.11	Mode = 0.73	Mode = 1.07	Mode = 0.150
P90 = 135.1	P90 = 14.9	P90 = 0.08	P90 = 0.61	P90 = 1.05	P90 = 0.100
P50 = 840.0	P50 = 32.8	P50 = 0.13	P50 = 0.75	P50 = 1.07	P50 = 0.211
P10 = 5,224.6	P10 = 72.3	P10 = 0.20	P10 = 0.92	P10 = 1.10	P10 = 0.445

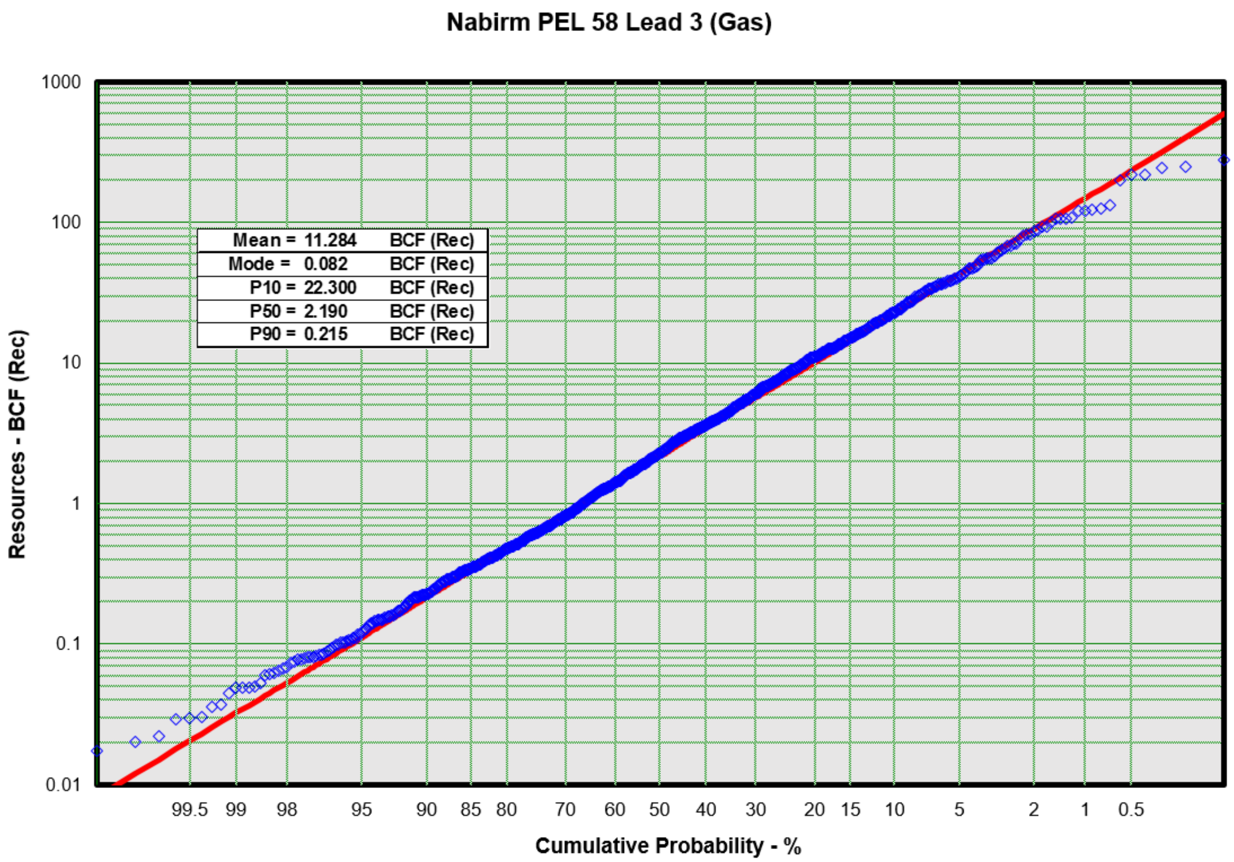
Lead 2 Volumetrics (Oil)



Lead 3 Parameter Probability Distributions (Gas)

Area (Acres)	Net Pay (feet)	Porosity	Sg	Bg	RF(gas)
Mean = 1,290.0	Mean = 49.9	Mean = 0.13	Mean = 0.76	Mean = 0.0176	Mean = 0.72
Mode = 48.4	Mode = 13.9	Mode = 0.11	Mode = 0.73	Mode = 0.0175	Mode = 0.67
P90 = 64.9	P90 = 10.0	P90 = 0.08	P90 = 0.61	P90 = 0.0169	P90 = 0.53
P50 = 432.0	P50 = 32.6	P50 = 0.13	P50 = 0.75	P50 = 0.0176	P50 = 0.70
P10 = 2,875.8	P10 = 106.4	P10 = 0.20	P10 = 0.92	P10 = 0.0183	P10 = 0.93

Lead 3 Volumetrics (Gas)



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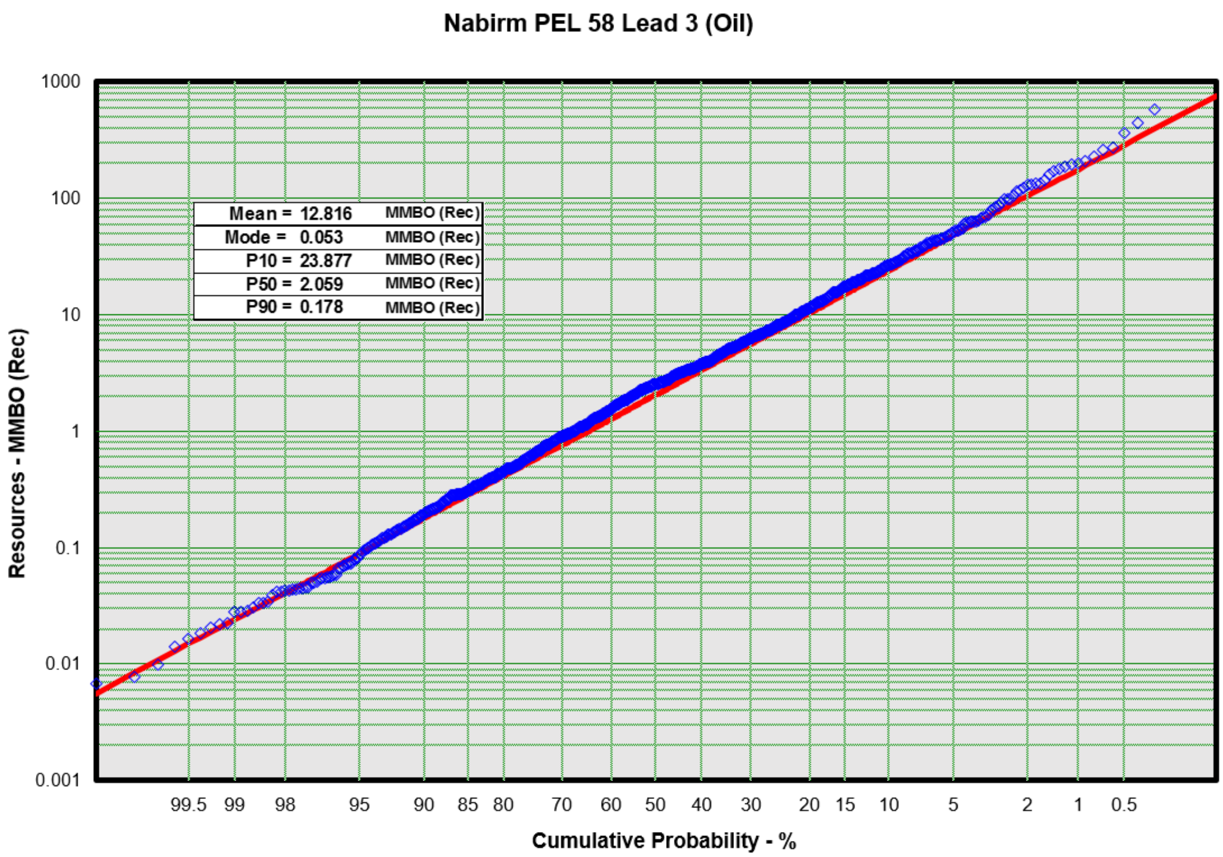
Lead 3 Parameter Probability Distributions (Oil)

Area (Acres)	Net Pay (feet)	Porosity	So	Bo	RF(oil)
Mean = 1,291.3	Mean = 49.9	Mean = 0.13	Mean = 0.76	Mean = 1.07	Mean = 0.250
Mode = 48.3	Mode = 13.9	Mode = 0.11	Mode = 0.73	Mode = 1.07	Mode = 0.150
P90 = 64.8	P90 = 10.0	P90 = 0.08	P90 = 0.61	P90 = 1.05	P90 = 0.100
P50 = 432.0	P50 = 32.6	P50 = 0.13	P50 = 0.75	P50 = 1.07	P50 = 0.211
P10 = 2,878.3	P10 = 106.3	P10 = 0.20	P10 = 0.92	P10 = 1.10	P10 = 0.445

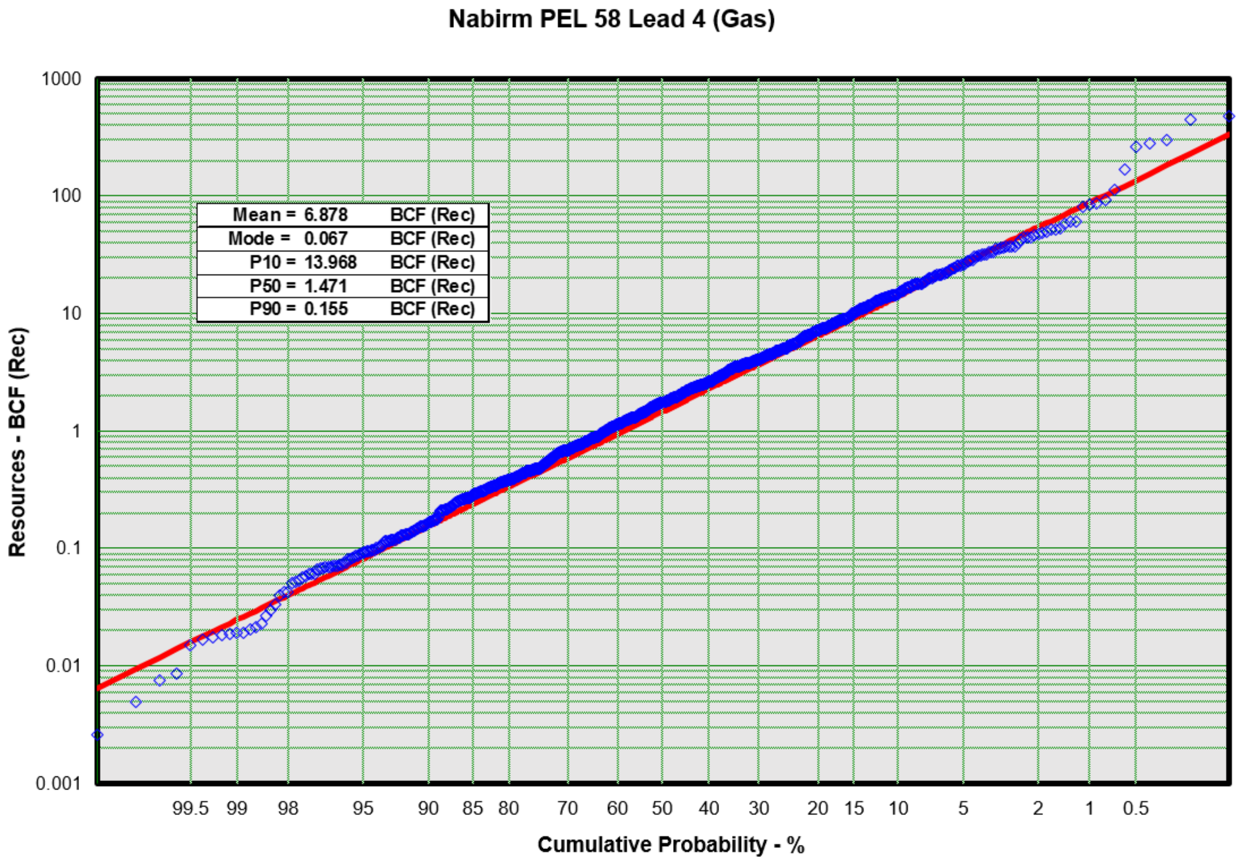
Lead 3 Volumetrics (Oil)



Lead 4 Parameter Probability Distributions (Gas)

Area (Acres)	Net Pay (feet)	Porosity	Sg	Bg	RF(gas)
Mean = 983.9	Mean = 49.9	Mean = 0.13	Mean = 0.76	Mean = 0.0176	Mean = 0.72
Mode = 36.5	Mode = 13.9	Mode = 0.11	Mode = 0.73	Mode = 0.0175	Mode = 0.67
P90 = 49.1	P90 = 10.0	P90 = 0.08	P90 = 0.61	P90 = 0.0169	P90 = 0.53
P50 = 328.0	P50 = 32.6	P50 = 0.13	P50 = 0.75	P50 = 0.0176	P50 = 0.70
P10 = 2,192.0	P10 = 106.4	P10 = 0.20	P10 = 0.92	P10 = 0.0183	P10 = 0.93

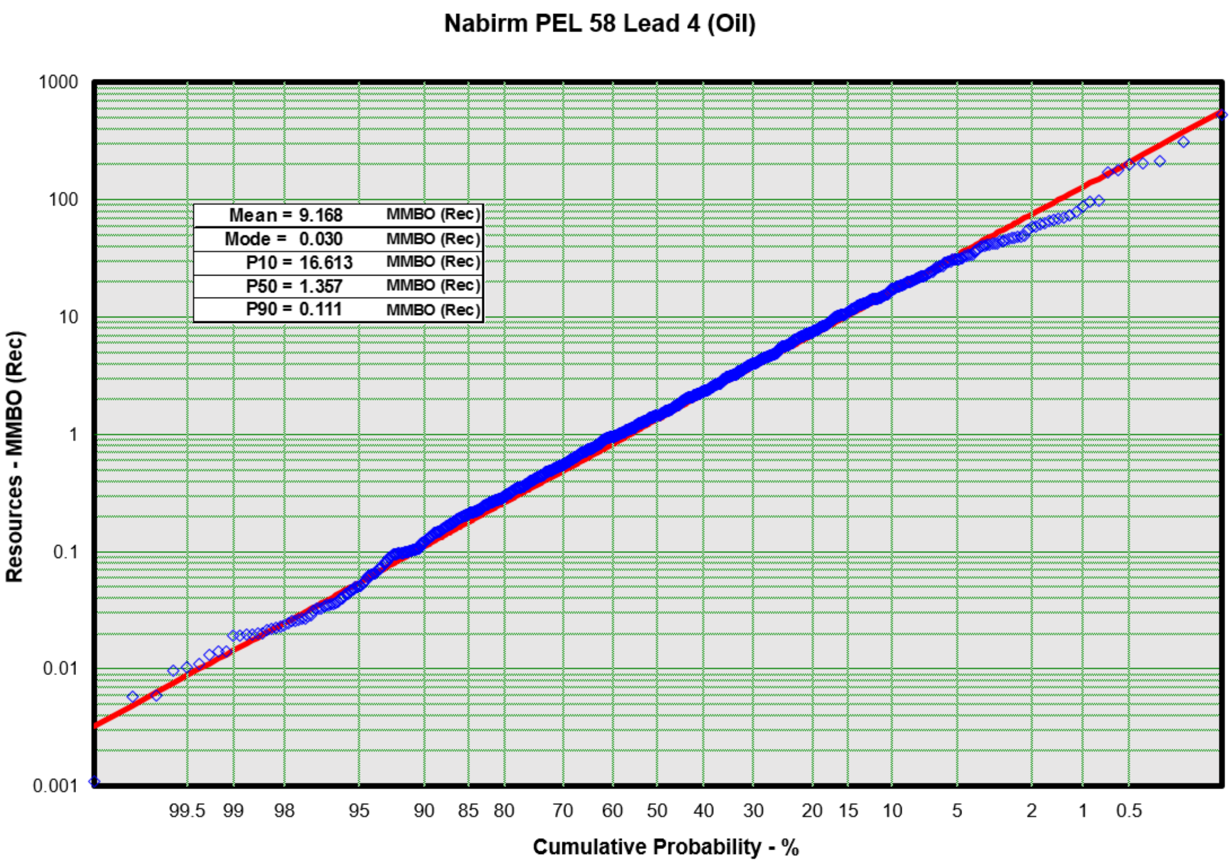
Lead 4 Volumetrics (Gas)



Lead 4 Parameter Probability Distributions (Oil)

Area (Acres)	Net Pay (feet)	Porosity	So	Bo	RF(oil)
Mean = 983.9	Mean = 49.9	Mean = 0.13	Mean = 0.76	Mean = 1.07	Mean = 0.250
Mode = 36.5	Mode = 13.9	Mode = 0.11	Mode = 0.73	Mode = 1.07	Mode = 0.150
P90 = 49.1	P90 = 10.0	P90 = 0.08	P90 = 0.61	P90 = 1.05	P90 = 0.100
P50 = 328.0	P50 = 32.6	P50 = 0.13	P50 = 0.75	P50 = 1.07	P50 = 0.211
P10 = 2,192.0	P10 = 106.3	P10 = 0.20	P10 = 0.92	P10 = 1.10	P10 = 0.445

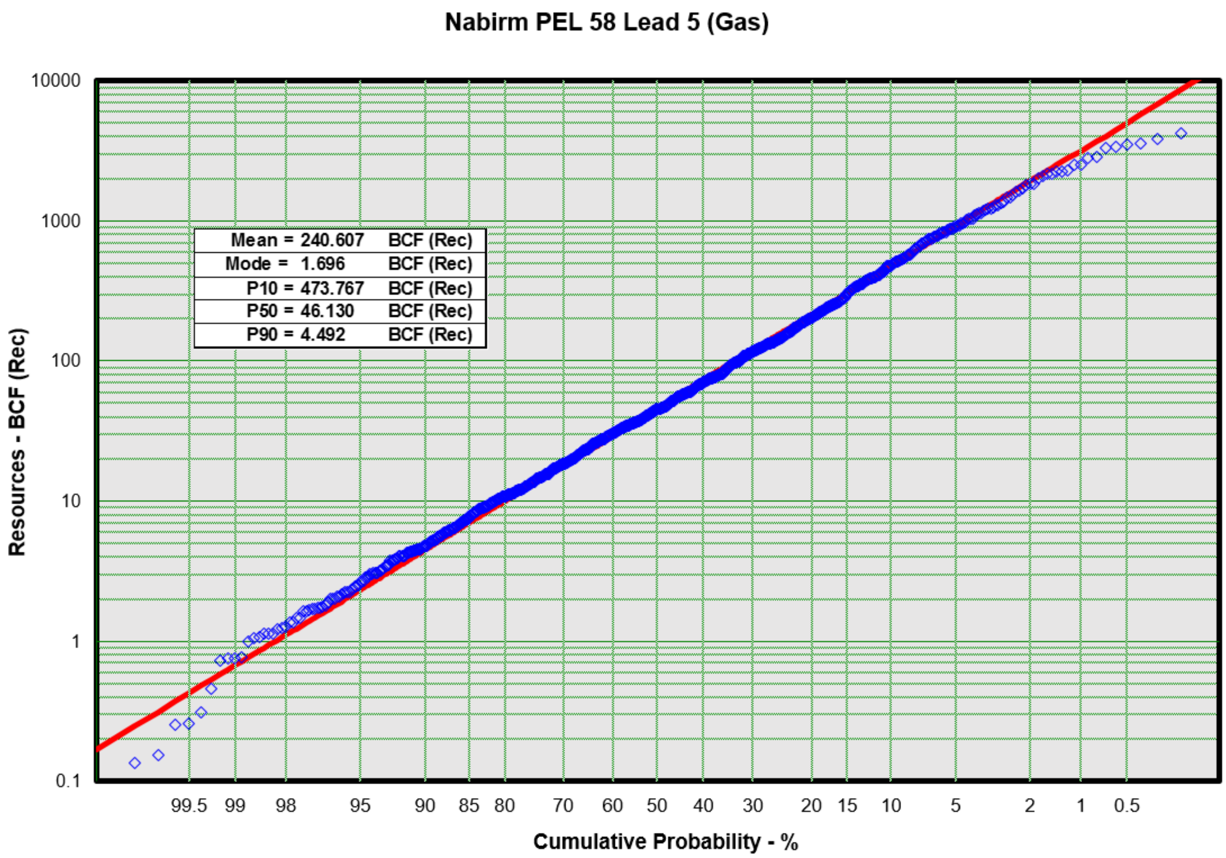
Lead 4 Volumetrics (Oil)



Lead 5 Parameter Probability Distributions (Gas)

Area (Acres)	Net Pay (feet)	Porosity	Sg	Bg	RF(gas)
Mean = 12,956.2	Mean = 49.9	Mean = 0.23	Mean = 0.76	Mean = 0.0176	Mean = 0.72
Mode = 542.8	Mode = 13.9	Mode = 0.21	Mode = 0.73	Mode = 0.0175	Mode = 0.67
P90 = 697.9	P90 = 10.0	P90 = 0.17	P90 = 0.61	P90 = 0.0169	P90 = 0.53
P50 = 4,500.0	P50 = 32.6	P50 = 0.22	P50 = 0.75	P50 = 0.0176	P50 = 0.70
P10 = 29,015.9	P10 = 106.4	P10 = 0.29	P10 = 0.92	P10 = 0.0183	P10 = 0.93

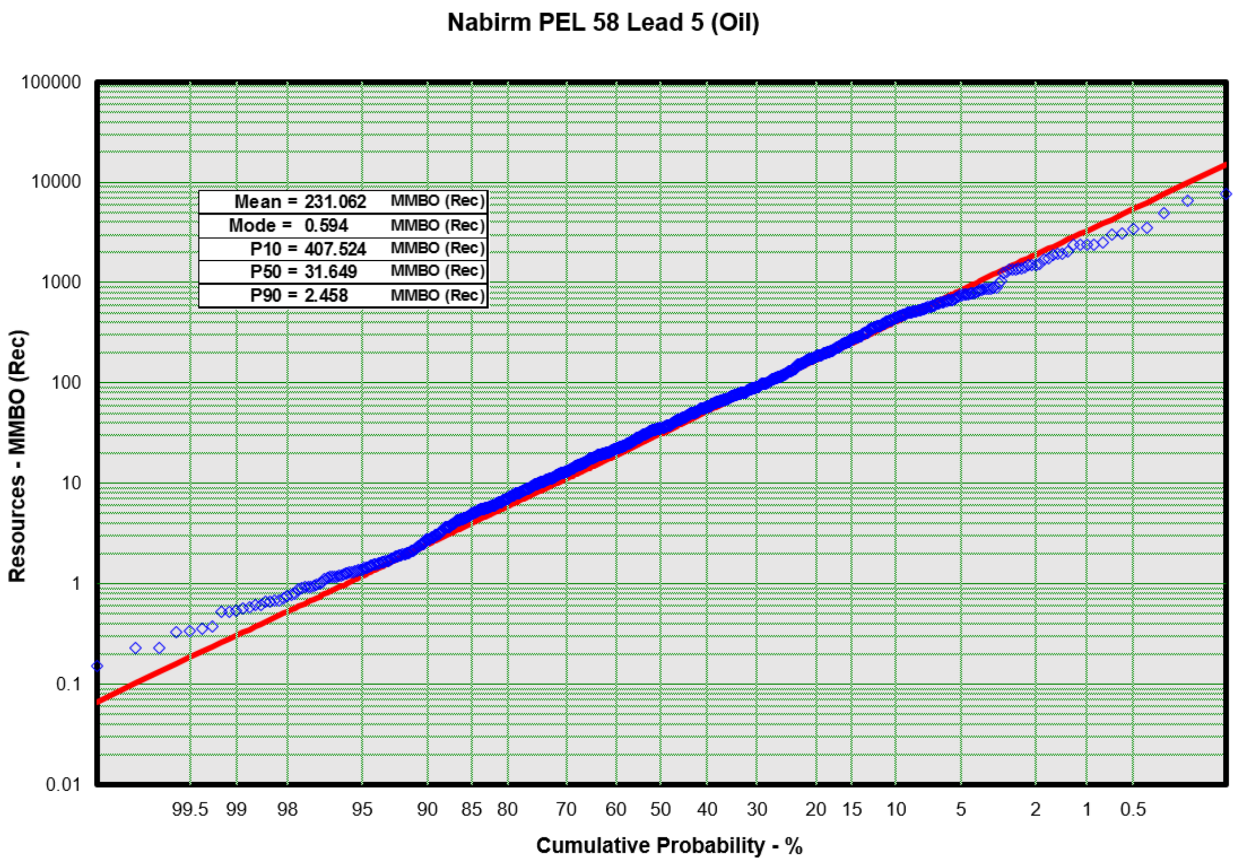
Lead 5 Volumetrics (Gas)



Lead 5 Parameter Probability Distributions (Oil)

Area (Acres)	Net Pay (feet)	Porosity	So	Bo	RF(oil)
Mean = 12,956.2	Mean = 49.9	Mean = 0.23	Mean = 0.76	Mean = 1.07	Mean = 0.250
Mode = 542.8	Mode = 13.9	Mode = 0.21	Mode = 0.73	Mode = 1.07	Mode = 0.150
P90 = 697.9	P90 = 10.0	P90 = 0.16	P90 = 0.61	P90 = 1.05	P90 = 0.100
P50 = 4,500.0	P50 = 32.6	P50 = 0.22	P50 = 0.75	P50 = 1.07	P50 = 0.211
P10 = 29,015.9	P10 = 106.3	P10 = 0.30	P10 = 0.92	P10 = 1.10	P10 = 0.445

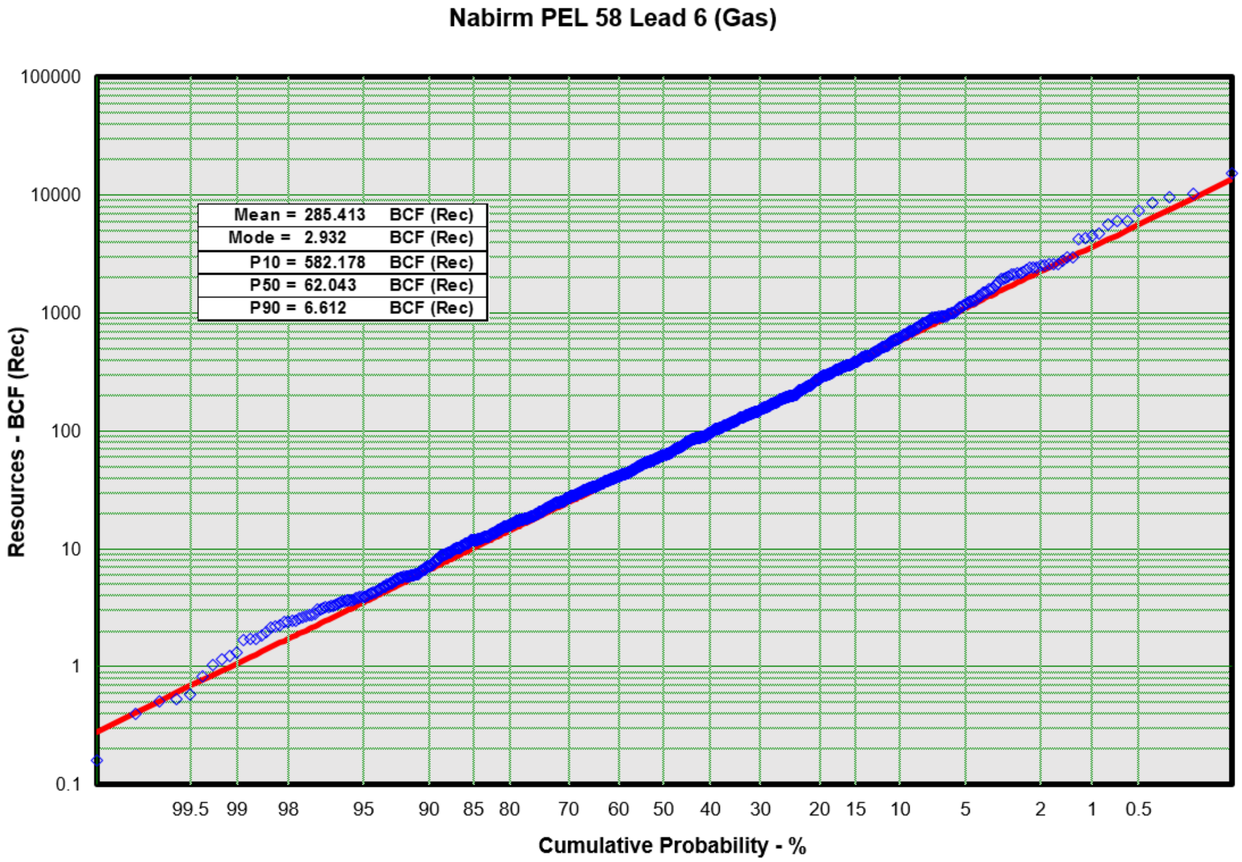
Lead 5 Volumetrics (Oil)



Lead 6 Parameter Probability Distributions (Gas)

Area (Acres)	Net Pay (feet)	Porosity	Sg	Bg	RF(gas)
Mean = 12,956.2	Mean = 69.0	Mean = 0.23	Mean = 0.76	Mean = 0.0176	Mean = 0.72
Mode = 542.8	Mode = 23.2	Mode = 0.21	Mode = 0.73	Mode = 0.0175	Mode = 0.67
P90 = 697.9	P90 = 16.1	P90 = 0.17	P90 = 0.61	P90 = 0.0169	P90 = 0.53
P50 = 4,500.0	P50 = 48.0	P50 = 0.22	P50 = 0.75	P50 = 0.0176	P50 = 0.70
P10 = 29,015.9	P10 = 142.9	P10 = 0.29	P10 = 0.92	P10 = 0.0183	P10 = 0.93

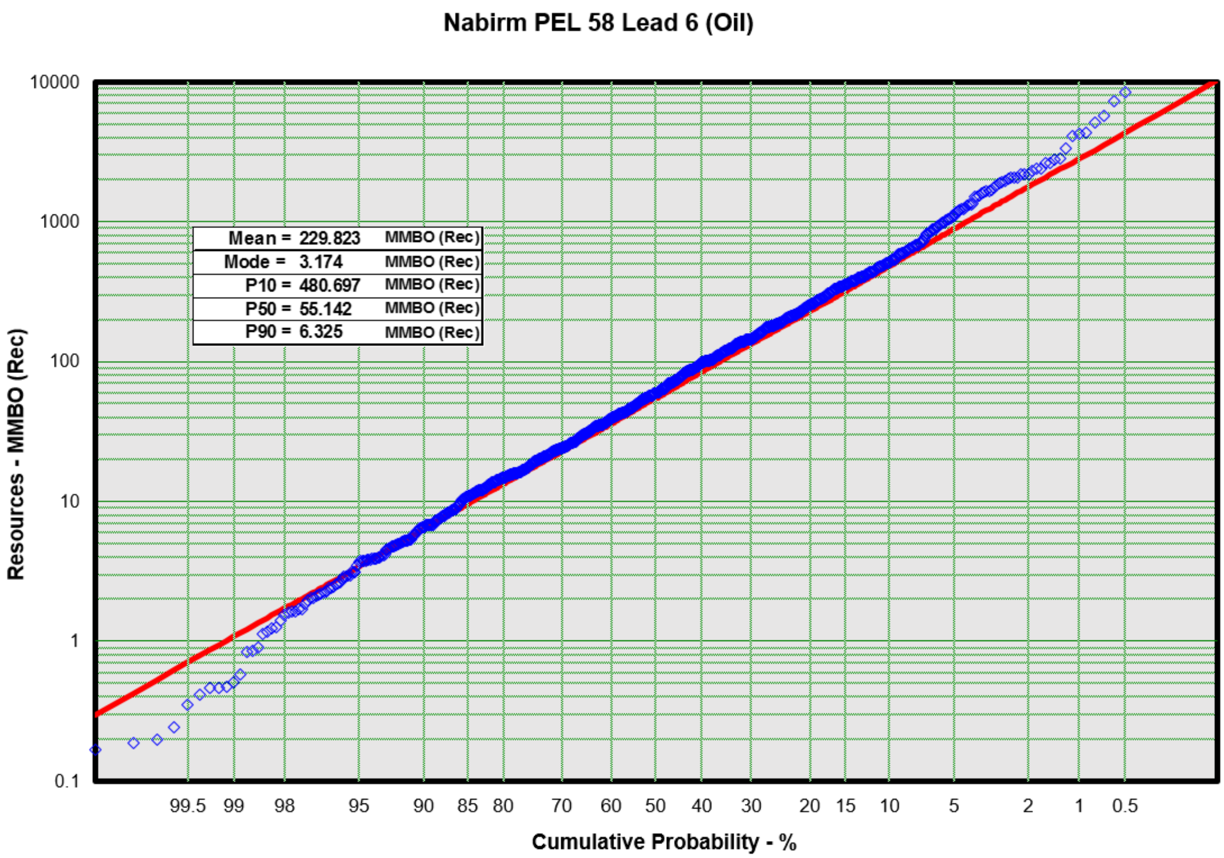
Lead 6 Volumetrics (Gas)



Lead 6 Parameter Probability Distributions (Oil)

Area (Acres)	Net Pay (feet)	Porosity	So	Bo	RF(oil)
Mean = 12,956.2	Mean = 69.0	Mean = 0.23	Mean = 0.76	Mean = 1.07	Mean = 0.250
Mode = 542.8	Mode = 23.2	Mode = 0.21	Mode = 0.73	Mode = 1.07	Mode = 0.150
P90 = 697.9	P90 = 16.1	P90 = 0.16	P90 = 0.61	P90 = 1.05	P90 = 0.100
P50 = 4,500.0	P50 = 48.0	P50 = 0.22	P50 = 0.75	P50 = 1.07	P50 = 0.211
P10 = 29,015.9	P10 = 142.9	P10 = 0.30	P10 = 0.92	P10 = 1.10	P10 = 0.445

Lead 6 Volumetrics (Oil)



8.5

8.6 PEL 58 Risked Recoverable Resource Summary

	Unrisked Oil (MMBO)			Risked Oil (MMBO)			Unrisked Gas (BCF)			Risked Gas (BCF)		
	P90	**P10**	**Pmean**	**P90**	**P10**	**Pmean**	**P90**	**P10**	**Pmean**	**P90**	**P10**	**Pmean**
Lead 1	0.62	46.15	21.98	0.06	4.15	1.98	0.67	46.24	21.80	0.06	4.16	1.96
Lead 2	0.48	35.98	17.15	0.04	3.24	1.54	0.55	36.95	17.36	0.05	3.33	1.56
Lead 3	0.18	23.88	12.82	0.02	2.15	1.15	0.22	22.30	11.28	0.02	2.01	1.02
Lead 4	0.11	16.61	9.17	0.01	1.50	0.83	0.16	13.97	6.88	0.01	1.26	0.62
Lead 5	2.46	407.52	231.06	0.22	36.68	20.80	4.49	473.77	240.61	0.40	42.64	21.65
Lead 6	6.33	480.70	229.82	0.57	43.26	20.68	6.61	582.18	285.41	0.60	52.40	25.69
Total	**10.2**	**1010.8**	**522.0**	**0.9**	**91.0**	**47.0**	**12.7**	**1175.4**	**583.3**	**1.1**	**105.8**	**52.5**

Table 4. Nabirm Lead Unrisked Recoverable Oil, Risked Recoverable Oil, Unrisked Recoverable Gas, Risked Recoverable Gas and Totals for PEL 58.

9 Basin Modeling

9.1 Basin Model Objectives

A 3D Basin Model has been generated by DSP Geosciences. The objective of the Basin Model was to provide an overview of Namibian margin hydrocarbon maturation with a focus on Nabirm PEL 58, Block 2113A. At this time there are limited grids surfaces from the NamibiaSPAN seismic dataset Regional Interpretation; also there are limited thermal calibration points along the Namibia margin. A thorough literature review has been conducted and an ArcMap project and TRINITY grids have been created.

9.1.1 Overview

The study area is located within the Walvis Basin of offshore Namibia (Figure 52). There are three grids that have been used in the 3D Basin Model, including Top Moho, Basement and Cretaceous – Tertiary Boundary.

The only established production in offshore Namibia occurs to the south within the Orange Basin at Kudu Field. Kudu Field is a large gas accumulation with 1-4 TCF of gas in Lower Cretaceous eolian dunes. Source rocks for the hydrocarbon accumulation are Lower Cretaceous. Oil has also been produced from syn-rift reservoirs of the AJ-1 well in South Africa.

9.1.2 Namibia Offshore Basins

Hydrocarbon discoveries within offshore Namibia have been limited to gas in northern Orange Basin (Bray et al., 1998, Figure 53). The Wingat-1 light oil test in the Walvis Basin demonstrates the potential for non-gas accumulations. The well tested 38-42 API oil in thin, sandy lenses within the Aptian source rock (Hodgson and Intawong, 2013). Aptian source rock has been proven along the entire coast through the Orange Basin. CT source rock (approximately at the Cretaceous – Tertiary boundary) is questionable in quality and thickness south or the Walvis ridge.

Figure 54 shows the evolution of the Namibia margin from Jurassic (150 Ma) to Present Day.

A comparison of Petroleum Systems from the Santos and Campos Basins of Brasil with the Namibia offshore basins is shown in Figure 55. This diagram demonstrates similar stratigraphy and age relationships within these basins. Cenomanian source rocks, although speculated as significant in Namibia, are unproven, but have potential. Aptian-Albian source rocks are the major contributor in South Africa. Barremian source rocks produce in syn-rift lakes (AJ-1 well, South Africa), but are largely untested on the Namibian coastline.

Serica Energy (2014) published a schematic cross-section of offshore Namibia Atlantic Margin - Luderitz Basin (Figure 56) that demonstrates the different plays recognized including syn-rift play, clastic shelf play, gravity toe-thrust play, carbonate shelf play, post-rift canyon channel turbidite play and carbonate platform play.

9.1.3 Preliminary NamibiaSPAN Horizons for the 3D Basin Model

The surfaces used in the 3D Basin Model, including Top Moho, Basement and the Cretaceous – Tertiary Boundary are preliminary horizon picks from the NamibiaSPAN PSTM 2D seismic data set. The CT horizon has not yet been mapped throughout the NamibiaSPAN area; a CT "proxy" horizon has been modeled at the middle of the Cretaceous to Basement sediment interval (Figure 57). Currently, the preliminary Basement horizon pick from NamibiaSPAN represents the base of the Cretaceous – Tertiary basin fill. Beneath this horizon there are possible syn-rift sediments, marine sediments, Seaward Dipping Reflectors (SDRs), volcanics and crystalline basement. The final PSDM horizon interpretation will provide a more thorough interpretation of lithologies that can be modeled (in the 3D Basin Model). The Basement Vitrinite Reflectance Map (Ro) will locally reflect Aptian source rocks overlying SDRs (outboard) and potential base Barremian rifts.

9.1.4 Stratigraphy

Generalized stratigraphy and source rock intervals of offshore Namibia are shown in Figure 58. The Aptian marine source is believed to be main source interval for known hydrocarbon accumulations within offshore Namibia. CT marine source rocks have been identified, yet there could be maturity risk. Neocomian syn-rift lacustrine source rocks are inferred but not proven along the Namibia margin. Permian Artinskian pre-rift sources are also postulated and occur in the Huab Basin onshore from Block 2113A and in the Toscinini 1 well to the north. Orange Basin Chronostratigraphy and source rock intervals are shown in Figure 59 (Kuhlman et al., 2011).

9.1.5 Maps used in the Basin Model

Four preliminary depth maps were used in the basin model. The Moho depth map, the Basement depth map (Figure 60), and the Cretaceous-Tertiary Boundary depth map (Figure 61) are primary products generated from horizon interpretation of the NamibiaSPAN 2D seismic data set. The Mid Cretaceous proxy map was created by approximating a surface midway between top Basement and the Cretaceous-Tertiary Boundary (Figure 61).

Potential Fields data used in the 3D Basin Model, including Magnetics and Gravity are shown in Figure 62. An interpreted Crustal Boundary is shown on the Potential Fields maps.

Temperature data are shown in Figure 63. Essentially no reliable temperature data is available within the Nabirm AOI. All IHS Energy reported field temperature data is only available for the Orange Basin. The Kudu Gas Field models provide a good calibration to a 30-35ºC/km gradient; this result is similar to prior regional work by authors from other projects.

9.1.6 Model Results

Two Heat Flow maps were generated within the 3D model including 1) Heat Flow derived from gravity data, and 2) Heat Flow derived from Moho depth (Figure 64). The two heat flow maps show similar results, yet the gravity derived heat flow values are lower in the southwestern part of Block 2113A than the Moho derived heat flow values. Mello et al., 2011 calibrated measured heat flow values from the Namibia margin (Figure 65) to measured data in Kudu Field. A gradient of 35 C/KM (this study), yields similar results in the Kudu area for the NamibiaSPAN top Basement grid.

Oil generation begins at a maturity value (Ro) of 0.6, continuing to generate oil up to a Ro of 1.3. Gas is generated from a 1.3 Ro through 1.75 Ro. Rocks with maturity values in excess of 1.75 Ro are considered overmature.

Figure 66 shows the maturity maps for two modeled surfaces, the Cretaceous-Tertiary and the Mid-Cretaceous proxy (based on a geothermal gradient of 35ºC/km and corresponding heat flow). The shallower Cretaceous-Tertiary map demonstrates that this surface is immature, with a maturity value less than 0.5 Ro. The Mid-Cretaceous proxy map maturity values reach Ro's of 0.65 – 0.80 in the western region of the AOI, indicating possible oil generation. The Mid-Cretaceous proxy horizon occurs above (shallower than) the CT source interval; the deeper CT horizon would be more mature due to its deeper depth.

The CT source rock (Figure 67) only has proven, high TOC marine, algal prone source north of the Walvis Ridge. The CT source data has been aliased along the coast to a continental facies in deltas. The CT deep water condensed section is mostly untested. The Hodgson and Intawong (2013) report of good CT source show no real data

Maturity (Ro) at the Basement horizon indicates oil and gas generation is possible (if source intervals are present) in the western portions of the Nabirm Block 2113A 3D Basin Model AOI. Within Block 2113A, Basement is immature where maturity is below 0.65 Ro. Approximately 20-60 km west, sediments at the same depth as basement are in the oil generation window (>0.65 Ro); farther west modeled maturity values indicate gas is being generated (>1.3 Ro; Figure 68, left image). Figure 68 (right image) illustrates the direction of possible hydrocarbon migration with migration vectors that flow to basement highs (possible traps) in Block 2113A. The hydrocarbons would be subject to long distance migration (20k or more); existing traps would require lateral and vertical migration pathways. The orange colors depict the possibility of gas as an end-stage migration product. The accumulations could also be oil.

The location of gridded seep data (HRT, 2011) and Basement maturity correlate well (Figure 69); i.e., where the Basement horizon sediments are in the oil generation window, sea surface oil seeps are recognized.

Figure 70 is a structural section across the 3D Basin Model AOI and into Block 2113A. The cross-section shows the sea floor, Cretaceous-Tertiary Boundary, Mid-Cretaceous proxy and Basement surfaces. The location of the Murombe and Wingat wells are shown, and the interval where oil was recovered from the Wingat well. Top early oil generation, top peak oil generation and the gas window are shown. A migration vector from the oil generation window is shown moving updip and landward toward Block 2113A. This migration model relies on lateral and vertical migration to basement highs. The best trapping potential occurs downdip in stratigraphic traps, or pinch-outs around basement horst blocks.

9.2 Basin Model Conclusions

The conclusions of the 3D Basin Modeling indicate that there is a proven, working Aptian-Barremian petroleum system in both syn-rift and early transgressive rift-to-drift flooding event in offshore Namibia. The Cenomanian - Turonian source rock appears thermally immature over most of the area. Additionally, there is limited evidence of thick CT source rock development with high TOC. Oil and gas shows and production correlate best with Aptian and older source intervals.

Maturation modeling within the 3D Basin Model AOI indicates that a Mid-Cretaceous proxy surface has maturation values indicating early maturity in the western AOI; the actual mapped CT horizon will occur deeper and be more mature. Maturity at the Basement horizon level indicates oil and gas generation is possible (if source intervals are present) in the western portions of the Nabirm Block 2113A 3D Basin Model AOI. Possible hydrocarbon migration and migration vectors flow to basement highs in Block 2113A. Long distance migration (20k or greater) would be necessary to charge traps in Block 2113A.

10 Conclusions & Recommendations

10.1 Seismic Data and Interpretation

The objective of the seismic interpretation was to identify key depositional features (reflection types, continuity, terminations, downlap, top lap, onlap), structural features (highs, lows, faults and fault styles including normal, reverse, strike-slip) and anomalous reflection packages. Key horizons were selected based on reflection strength, continuity and their relative position to genetically related successions of sediments. Time structure maps, depth structure maps, isochrons and isopachs were generated for key horizons including Surface 1, Surface 2, Surface 3 and Basement.

Utilizing the correlation of well 2213 6-1 with NamibiaSPAN horizons, Surface 1 approximately correlates to top Cretaceous. Surface 2 and Surface 3 are of unknown age, yet based on the NamibiaSPAN horizon interpretation the horizons maybe Campanian, Santonian or Coniacian age. Karoo age sediments may occur below Surface 3 or may occur as a thin veneer adjacent to basement throughout the survey area.

Time structure maps, isochrons, depth structure maps and isopachs were created for the Block 2113A 2D survey area. Additional isopach maps were created to identify possible stratigraphic traps above basement.

10.2 Petroleum Charge

Offshore Namibia is an oil-prone area with multiple recognized marine and lacustrine source rocks. Source rock type, richness, distribution and level of maturity are favorable for the generation and expulsion of significant volumes of oil. Three source intervals have been identified in offshore Namibia: rift (lacustrine), Lower Cretaceous Barremian-Aptian (marine) and Cenomanian-Turonian (marine) sources. Pre-rift (Karoo) source intervals are likely present and may generate gas, yet the offshore data is inadequate to assess their contribution.

Exploration in blocks adjacent to PEL 58 has identified an "oil mature fairway". Hydrocarbons generated within this fairway would be migrating eastward and updip toward Block 2113A. In onshore blocks, exploration is focused on Karoo age sediments.

10.3 Reservoir

There is a high likelihood of Karoo sediments in Block 2113A. The Lower Cretaceous Twyfelfontein Sandstone has been mapped extensively onshore and likely extends into the offshore area. The Twyfelfontein Formation - Verbrande/Tsarabis/Huab Formations would be key reservoir-source rock components of a viable Petroleum System within Block 2113A.

10.4 Lead Risk and Volumetrics

Exploration risk is determined by assessment of lead specific risk elements including trap, reservoir, seal and source. The probability of geologic success (Pg) is based on objective knowledge, historical data, extrapolations and subjective judgements of geological information. The Pg will vary from lead to lead and is defined as the product of the component probabilities of geological risk elements.

Volumetric estimation was performed using lognormal distributions to quantify geologic parameters, reservoir parameters and to understand upside, downside, most likely and mean resource values. Monte Carlo processes were used to combined cumulative probability distributions of geologic parameters and calculate hydrocarbon volumes (oil and gas).

10.5 Hydrocarbon Maturity and Migration

3D Basin Modeling was performed within an area of interest (AOI) including Block 2113A. The objective of the Basin Model was to provide an overview of Namibian margin hydrocarbon maturation with a focus on Nabirm PEL 58, Block 2113A. The surfaces used in the 3D Basin Model, including Top Moho, Basement and Cretaceous– Tertiary Boundary are preliminary horizon picks from the NamibiaSPAN PSTM 2D seismic data set. The CT horizon has not yet been mapped throughout the NamibiaSPAN area. A CT "proxy" horizon was modelled at the middle of the Cretacous to Basement sediment interval. Model results indicate that the Cretaceous-Tertiary surface is immature with a maturity value less than 0.5 Ro. The Mid-Cretaceous proxy map maturity values reach 0.65 – 0.80 in the western region of the AOI, indicating possible oil generation. Basement horizon maturity indicates oil and gas generation is possible in the western portions of the AOI. Within Block 2113A, Basement is immature. 20-60 km west, sediments are in the oil generation window and farther west still, modeled maturity values indicate gas is being generated. It is possible that hydrocarbon migration, with migration vectors that flow to basement highs in Block 2113A, has occurred.

10.6 Petroleum Leads

Six leads have been identified within the 2D seismic survey area of Block 2113A. There are four structural leads, one stratigraphic lead and one possible amplitude anomaly lead, also stratigraphically trapped. The structural leads are prominent four-way closures that may be unfaulted or faulted. These features occur within the basement section, at the top of basement underlying the onlapping Tertiary, Cretaceous and possible Karoo sediments. The stratigraphic lead occurs where the Cretaceous, Tertiary or Karoo age sediments thin and onlap basement and is structurally closed by the overlying structural surface. One anomalous amplitude lead is recognized in the southernmost 2D survey area.

10.7 Prospect/Lead Economics: Future Work

The OOIP and OGIP prospective resource estimates contained herein will form the basis of an economic evaluation of identified Leads. To carry out this evaluation, however, the following additional information is required:

- Recoverable resource estimates;
- Field development plans;
- Production profiles;
- Opex profiles;
- Capex profiles;
- Commodity price decks; and

- Fiscal terms.

An economic analysis of the PEL 058 Lead portfolio will be carried out as part of the future work program.

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