FORM 51-102F3

MATERIAL CHANGE REPORT

Item 1 – Name and Address of Company

Eco (Atlantic) Oil & Gas Ltd. (the "Company")
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Item 2 – Date of Material Change

February 18, 2014

Item 3 – News Release

A news release announcing the material change was disseminated via Canada Newswire on February 18, 2014.

Item 4 – Summary of Material Change

The Company has received an updated independent Lead Report, attached hereto (the "Report"), for Block 2012A (the "Cooper Block") in the Walvis Basin, offshore Namibia, supporting a P_{50} Best Estimate of 4.5 billion barrels of gross prospective oil over the existing targets.

Item 5 – Full Description of Material Change

The Company has received the Report for the Cooper Block in the Walvis Basin, offshore Namibia. The Report was prepared by Gustavson Associates LLC ("Gustavson") of Colorado, USA, in accordance with Canadian National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") and supports a P_{50} Best Estimate of 4.5 billion barrels of gross prospective oil over the existing targets.

The Report evaluated an additional 700 Klms of 2D Seismic Data recently acquired by the Company. Gustavson completed an assessment of the Gross Prospective Unrisked Resource as of February 18, 2014. The Report is based upon interpretation of over 1,450 line kilometers of 2D seismic and an analysis of the recent detailed report completed by PGS on the Cooper Block. The Report updates Gustavson's original lead report for Cooper Bock, dated February 1, 2012.

The Report has produced seven leads. Based on probabilistic analysis, the Gross Prospective Unrisked Resources for the seven leads are summarized below:

	Oil in Place[1] (MMBO)[2]			Prospective Oil Resources (MMBO) [2]		
Lead	**Low Estimate (P_{90})**	**Best Estimate (P_{50})**	**High Estimate (P_{10})**	**Low Estimate (P_{90})**	**Best Estimate (P_{50})**	**High Estimate (P_{10})**
A (Campanian)	413.0	784.0	1,369.6	90.8	179.9	327.9
B (Albian)	1,317.3	2,478.5	4,271.3	290.2	569.4	1,029.8
C (Campanian)	1,658.8	3,528.0	6,797.4	368.7	812.2	1,662.2
D (Maastrichtian)	544.2	1,128.3	2,160.0	120.4	256.6	516.4
Flat (Campanian)	339.3	628.4	1,104.8	73.0	143.8	265.0
Campanian Fan	4,939.1	9,512.1	17,596.3	1,083.5	2,177.0	4,208.2
Albian Channel	942.6	1,744.2	2,979.9	208.4	394.4	711.4
Total	**10,154.3**	**19,803.5**	**36,279.4**	**2,235.1**	**4,533.3**	**8,720.9**

(1) Oil in place does not represent a recoverable volume.
(2) Million barrels of oil

The Cooper license covers 5,800 square kilometers (1,433,000 acres) and is situated within the Walvis Basin, offshore Namibia. Eco Atlantic holds a 70% working interest in the Cooper license, Azimuth Ltd. hold 20% working interest, and the National Petroleum Corporation of Namibia (NAMCOR) hold a 10% working interest. The estimates in the Report have been prepared in accordance with the definitions and guidelines set forth in NI 51-101. The estimates do not include considerations for the risk of failure in exploring for these resources.

"Prospective resources" are defined as those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. Prospective resources have both an associated chance of discovery (geological chance of success) and a chance of development (economic, regulatory, market, facility, corporate commitment or political risks). The chance of commerciality is the product of these two risk components. The prospective resource estimates referred to herein have not been risked for either the chance of discovery or the chance of development. There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The Low Estimate represents the P_{90} values from the probabilistic analysis (i.e. the value is greater than or equal to the P_{90} value 90% of the time), while the Best Estimate represents the P_{50} values and the High Estimate represents the P_{10}. Actual resources may be greater or less than those calculated.

Statements relating to "resources" and "prospective resources" are deemed to be forward-looking statements, as they involve the implied assessment that the resources described exist in the quantities predicted or estimated. This assessment is based on a number of assumptions, such as geological, technological and engineering estimates, and is subject to a variety of risks, uncertainties and other factors that could cause actual results to differ materially from those anticipated in the estimates. These uncertainties and risks include, but are not limited to: (1) the fact that there is no certainty that the zones of interest will exist to the extent estimated or that the zones will be found to have oil and/or natural gas with characteristics that meet or exceed the minimum criteria to make it commercially recoverable to the extent estimated; (2) the number of competitors in the oil and gas industry with greater technical, financial and operations resources and staff; (3) potential liabilities for pollution or hazards against which the company cannot adequately insure or which the company may elect not to insure; (4) contingencies affecting the classification as reserves versus resources which relate to the following issues as detailed in the Canadian Oil and Gas Evaluation Handbook: ownership considerations, drilling requirements, testing requirements, regulatory considerations, infrastructure and market considerations, timing of production and development, and economic requirements; and (5) other factors beyond the Company's control.

Item 6 – Reliance on subsection 7.1(2) of National Instrument 51-102

Not applicable

Item 7 – Omitted Information

Not applicable

Item 8 – Executive Officer

Gil Holzman, President and Chief Executive Officer of Eco (Atlantic) Oil & Gas Ltd. is knowledgeable about the material change and this report and may be contacted at (416) 361-2211.

Item 9 – Date of Report

February 26, 2014

Leads for Cooper Block (2012A) Offshore Namibia

Prepared According to National Instrument 51-101

Date of this Report: February 18, 2014

Prepared for:

Eco Namibia (PTY), Ltd

and

Kinley Exploration LLC

Prepared By:

GUSTAVSON ASSOCIATES
5757 CENTRAL AVE. SUITE D BOULDER, COLORADO 80301 USA

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E-mail: gustavson@gustavson.com

Leads for Cooper Block (2012A) Offshore Namibia

Prepared According to National Instrument 51-101

Date of this Report: February 18, 2014

Prepared for:

Eco Namibia (PTY), Ltd

ECO OIL & GAS LTD.

and Kinley Exploration LLC

Prepared By:

Letha C. Lencioni
Registered Petroleum Engineer
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1. EXECUTIVE SUMMARY

The subject area is located in the offshore of Namibia which is on the west coast of southern Africa situated south of Angola, north of South Africa, and west of Botswana. Eco Namibia (PTY), Ltd (ECO) acquired the licenses to four blocks in the Namibian offshore. This report describes an update to the preliminary assessment of the hydrocarbon potential of Block 2012A, named Cooper Block. The Cooper Block is within the Walvis Basin in water depths ranging from 10 to 500 meters. This report is an update and revision to the report dated July 15, 2011 titled "Leads for Cooper Block (2012A) Offshore Namibia" prepared for ECO Oil and Gas (Services) Namibia (PTY), Ltd and Kinley Exploration LLC. This update is based on new data provided by the Client. These new data include additional seismic data, the correction of the location of the key well, and an interpretation by Petroleum Geo-Services (PGS) done on behalf of the Client.

The data provided include speculative 2D seismic data and reports from five wells that were drilled in the vicinity of the block. The interpretation of over 1,450 line kilometers of 2D seismic data that was acquired by TGS in late 1992 over Cooper Block has produced seven leads. The leads are called A, B, C, D, Flat, Campanian Fan, and Albian Channel. Leads A, B, C, D, and Flat are interpreted as structures with associated faults, and Leads Campanian Fan and Albian Channel are interpreted to be stratigraphic traps. The faults in the structural leads are interpreted to extend down into the Turonian- and Aptian-aged source rock. The leads are interpreted to be within Mid to Upper Cretaceous aged strata that would be a marine sand-shale sequence. Additionally, the structures that set up these leads persist down through the Lower Cretaceous section and may lead to additional potential reservoirs. The total potential gross reservoir section from the Late through Early Cretaceous is estimated to be 1,500 meters thick and would most likely be sourced by Turonian and Aptian aged rocks. Oil seeps have been observed in the area and HRT Namibia has observed oil shows recently in the Wingat-1 well in Block 2212 which is approximately 210 kilometers (130 miles) south of the Cooper Block. The Wingat well also identified two well-developed source rocks, including an Aptian source rock, which were reported to both be in the oil generating window. The oil from this well was described as light oil at 41° API with a GOR of 1,193 scf/bbl. In addition there is the potential for Albian-aged reef carbonate plays similar to those discovered in the Santos Basin in the offshore of Brazil.

The current Cretaceous leads range in size from 2 to 1,113 square kilometers with gross thicknesses ranging from 60 to 280 meters thick at a depth of 1,250 to 2,850 meters. The hydrocarbon generated by the local source rocks is expected to be 40 ° API oil with an Associated Gas Oil Ratio (GOR) of 1,200 cubic feet per barrel[1]. Based on probabilistic estimates, the gross unrisked Prospective Resources for the five leads are listed below in Table 1-1.

Table 1-1 Gross Prospective Unrisked Resource Estimates by Lead

	Oil in Place, MMBO			**Prospective Oil Resources, MMBO**		
Lead	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A (Campanian)	413.0	784.0	1,369.6	90.8	179.9	327.9
B (Albian)	1,317.3	2,478.5	4,271.3	290.2	569.4	1,029.8
C (Campanian)	1,658.8	3,528.0	6,797.4	368.7	812.2	1,662.2
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Flat (Campanian)	339.3	628.4	1,104.8	73.0	143.8	265.0
Campanian Fan	4,939.1	9,512.1	17,596.3	1,083.5	2,177.0	4,208.2
Albian Channel	942.6	1,744.2	2,979.9	208.4	394.4	711.4
Total	10,154.3	19,803.5	36,279.4	2,235.1	4,533.3	8,720.9

(MMBO = million barrels of oil)

Note that these estimates do not include consideration for the risk of failure in exploring for these resources. Prospective Resources are defined as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and

[1] Based on press release from HRT Wingat-1 well analysis

development and may be sub-classified based on project maturity."[2] There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The Low Estimate represents the P_{90} values from the probabilistic analysis (in other words, the value is greater than or equal to the P_{90} value 90% of the time), while the Best Estimate represents the P_{50} and the High Estimate represents the P_{10}.[3]

The geologic history of the area includes the time period when the separation of the South American continent from the African continent occurred. Many oil and gas fields have been discovered on both sides of the Atlantic Ocean in western Africa as well as Brazil. The Santos Basin in the offshore of southern Brazil has had a number of commercial hydrocarbon discoveries recently and could be considered the mirror image of the Walvis Basin in Namibia where Cooper Block is located.

ECO's future planned expenditures for this project include a budget over the next six years estimated to be US$131,750,000. The next phase of the exploration of this block would include the acquisition of new 2D and 3D seismic data. ECO would then drill a well to test the ideas presented in this report. The current interest in this block is 70% ECO, 20% Azimuth Ltd and 10% NAMCOR. Azimuth Ltd will fund 40% of the 3D seismic acquisition costs.

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[2] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook, Second Edition*, Volume 1, September 1, 2007, pg 5-7.
[3] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook, Second Edition*, Volume 1, September 1, 2007, pg 5-7.

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3. INTRODUCTION

3.1 AUTHORIZATION

Gustavson Associates LLC (the Consultant) has been retained by Eco Namibia (PTY), Ltd and Kinley Exploration LLC collectively known as ECO (the Client, ECO) to prepare an updated Report under Canada's National Instrument 51-101, *Standards of Disclosure For Oil and Gas Activities*, regarding the Block 2012A (Cooper Block) concession position in the offshore of the country of Namibia.

3.2 INTENDED PURPOSE AND USERS OF REPORT

The purpose of this Report is to support the Client's potential filing with the Toronto Stock Exchange (TSX).

3.3 OWNER CONTACT AND PROPERTY INSPECTION

This Consultant has had frequent contact with the Client. This Consultant has not personally inspected the subject property.

3.4 SCOPE OF WORK

This Report is intended to describe and quantify the Lead Prospective Resources contained within Cooper Block that are subject to a petroleum license agreement with the Namibian government.

3.5 APPLICABLE STANDARDS

This Report has been prepared in accordance with Canadian National Instrument 51-101. The National Instrument requires disclosure of specific information concerning prospects, as are provided in this Report.

3.6 ASSUMPTIONS AND LIMITING CONDITIONS

The accuracy of any estimate is a function of available time, data and of geological, engineering, and commercial interpretation and judgment. While the interpretation and estimates presented herein are believed to be reasonable, they should be viewed with the understanding that additional analysis or new data may justify their revision. Gustavson Associates reserves the right to revise its opinions, if new information is deemed sufficiently credible to do so.

3.7 INDEPENDENCE/DISCLAIMER OF INTEREST

Gustavson Associates LLC has acted independently in the preparation of this Report. The company and its employees have no direct or indirect ownership in the property appraised or the area of study described. Ms. Letha Lencioni is signing off on this Report, which has been prepared by her as a Qualified Reserves Evaluator, with the assistance of others on Gustavson's staff. Our fee for this Report and the other services that may be provided is not dependent on the amount of resources estimated.

4. DISCLOSURES REGARDING LEADS

4.1 LOCATION AND BASIN NAME

The subject area is located in the offshore in the country of Namibia which is on the west coast of southern Africa situated south of Angola, north of South Africa, and west of Botswana (Figure 4-1).

Figure 4-1 Map of the Country of Namibia (Trek, 2008)

The Cooper Block is located in the northern part of the Walvis Basin as seen in Figure 4-2 which is located in the offshore of Namibia on the west coast of southern Africa.

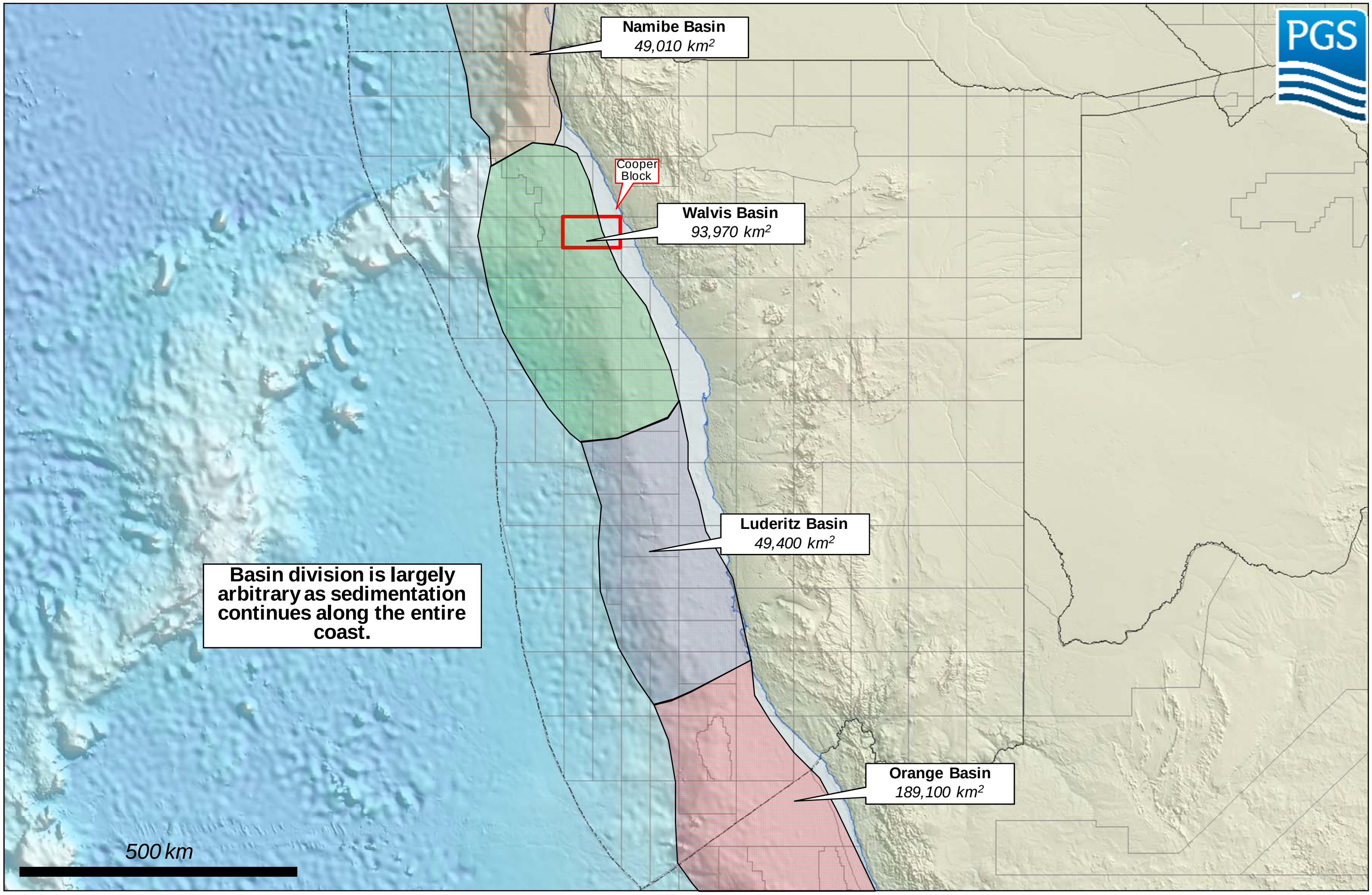


Figure 4-2 Map Showing Location of Cooper Block within the Walvis Basin (after PGS 2013)

4.2 BATHYMETRY

The Cooper Block is located in an area where the water depth ranges from less than 100 meters to over 500 meters (Figure 4-3). All of the lead areas are within the 200 to 500 meter water depth range.

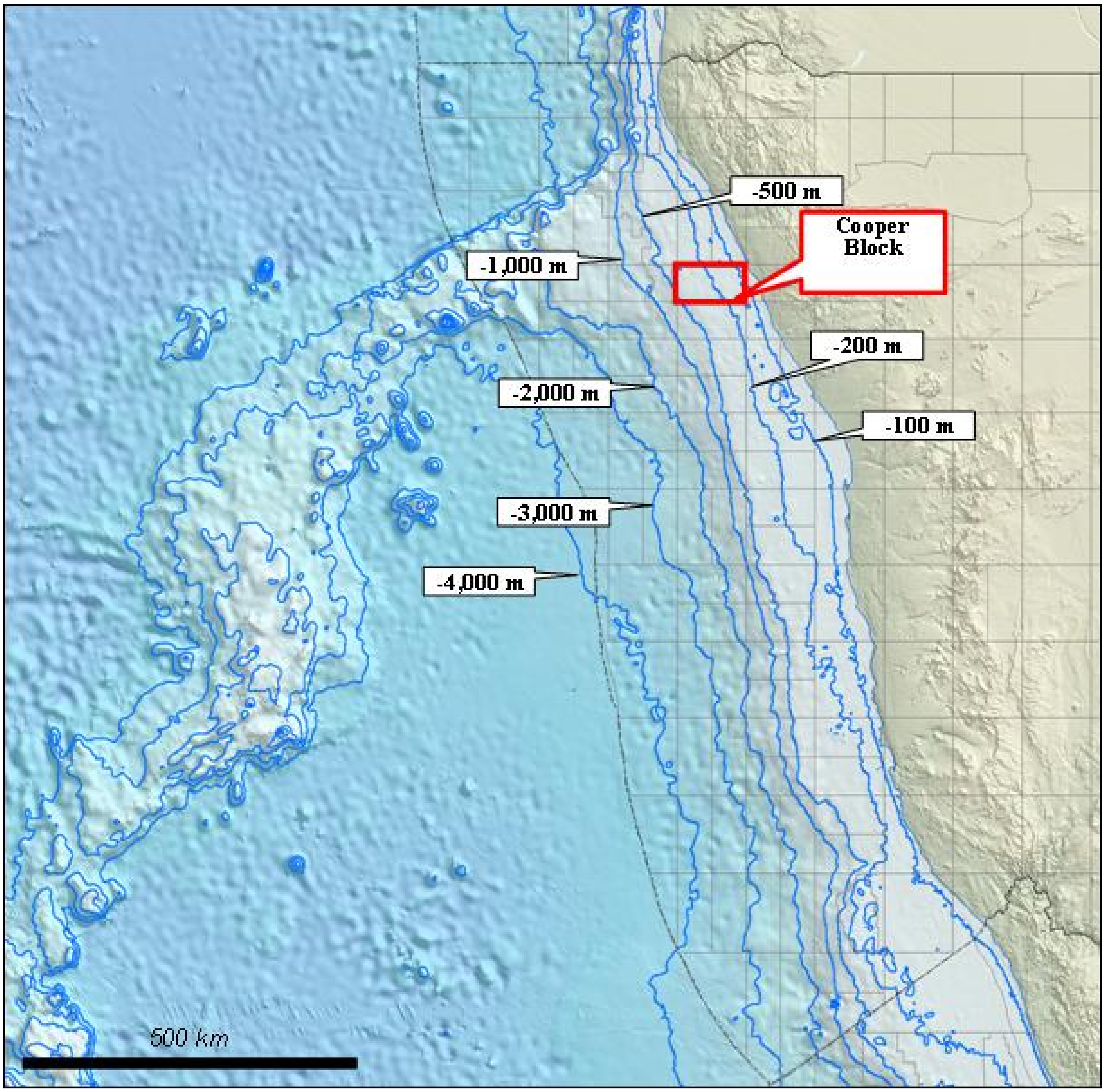


Figure 4-3 Bathymetry Map for the Offshore of Namibia near Cooper Block (after PGS 2013)

4.3 GROSS AND NET INTEREST IN THE PROPERTY

Eco Namibia Ltd. owns 70% of the working interest in the license with Azimuth Ltd. Owning 20% of the working interest and NAMCOR, the National Petroleum Corporation of Namibia, holding the remaining 10%.

4.4 EXPIRY DATE OF INTEREST

The expiration date for the Exploration License 0030 in Cooper Block (Block 2012 A) is four years from the date of issue, specifically March 14, 2015. ECO has the ability to extend this date of expiration if desired through a permit renewal prior to the expiration date.

4.5 DESCRIPTION OF TARGET ZONES

The interpretation of over 1,450 kilometers of 2D seismic data in offshore Namibia acquired by TGS in late 1992 over Cooper Block has shown excellent Eocene, Upper Cretaceous Maastrichtian, and Lower Cretaceous Albian/Aptian reflectors that are tied back to the 2012/13-001 well. These reflectors have been mapped throughout the project area and form the basis for geologic horizon identification. The Leads identified as A, B, C, D, and Flat are structural in nature, fault bounded and have structural closure in all cases of over 75 meters in the Late Cretaceous section and Leads Campanian Fan and Albian Channel are interpreted to be stratigraphic traps in the Late and Early Cretaceous section (Figure 4-4). The faults in the structural leads are interpreted to extend down into the Turonian aged source rock.

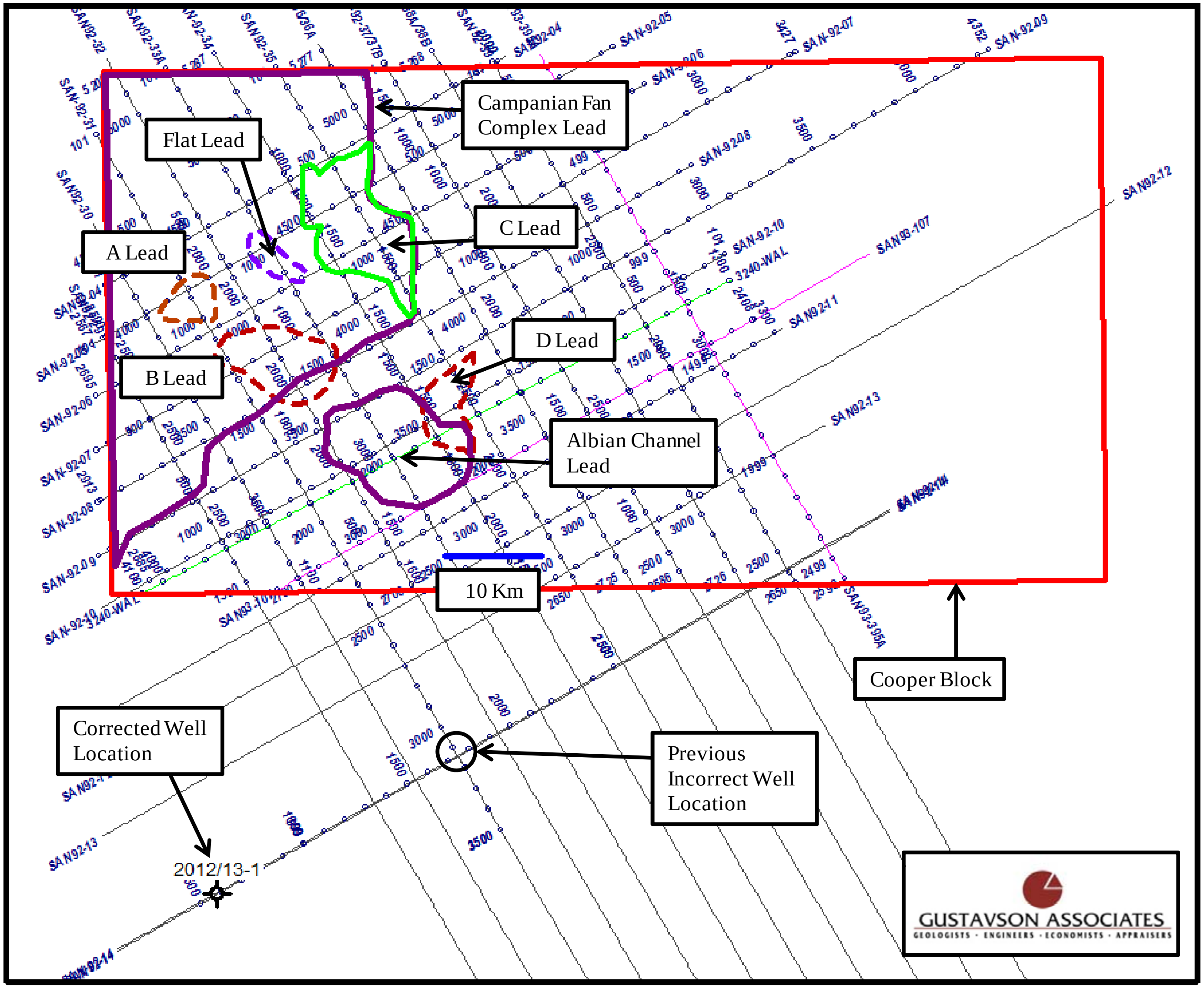


Figure 4-4 Location of Leads in the Southwestern Area of Cooper Block, Namibia

These structures persist down through the Early Cretaceous in most cases but these intervals were not included in the preliminary areas. The zones of interest are defined as the Early through Late Cretaceous. The Sasol 2012/13-1 well location, which was based on preliminary information, was found to be incorrect based on the Final Well Report from Sasol recently obtained from the Client. The well has been correctly positioned approximately 30 kilometers to the west southwest of the previous location along seismic line SAN-92-14. The repositioning of the well changed the ages of the Leads from the previous report; however, the structural leads A, B, C, D, and Flat are essentially in the same place time-wise on the seismic data.

4.6 DISTANCE TO THE NEAREST COMMERCIAL PRODUCTION

Oil is being produced in the offshore of Angola approximately 600 kilometers to the north from multiple fields and gas has been produced from the Kudu Field approximately 900 kilometers to the south of Cooper Block in the offshore of Namibia.

4.7 PRODUCT TYPES REASONABLY EXPECTED

Oil of 40 degrees API with associated gas is the expected hydrocarbon type to be found in these leads due to the Turonian–Cenomanian aged source rock being just within the hydrocarbon generating window. The HRT Wingat well drilled approximately 210 kilometers (130 miles) south of the Cooper Block also identified a well-developed Aptian source rock, which was reported to be in the oil generating window. The oil from this well was described as light oil at 41^{o} API with a 1,193 scf/bbl GOR. A preliminary study by PGS based on geothermal gradients derived from the existing well information indicates that the Turonian- to Cenomanian-aged source rock could be in the oil window in the western part of the Cooper Block and the Aptian-aged source rock could be within the oil window throughout most of the block.

4.8 RANGE OF POOL OR FIELD SIZES

The seven leads have minimum to maximum areas of closure ranging from 2 to 1,113 square kilometers with gross thicknesses ranging from 60 to 280 meters. The gross thickness for the

Campanian is estimated from the isopach map derived from the seismic (Figure 5-14). The size of the resource accumulations within these leads ranges from a Low Estimate of 73 MMBO for the Flat lead up to a High Estimate of 4,208 MMBO for the Campanian Fan lead.

4.9 DEPTH OF THE TARGET ZONE

These leads are estimated to occur at a depth range of 1,250 to 2,850 meters with a normal pressure and temperature gradient. This is based on a time-depth relationship from the Block 1911/10-1 well which had a check-shot included in the data provided and the tie to the Sasol 2012/13-1 well.

4.10 IDENTIFY AND RELEVANT EXPERIENCE OF THE OPERATOR

Eco Namibia is a wholly owned subsidiary of Eco (Atlantic) Oil & Gas Ltd ("ECO"). Eco (Atlantic) Oil & Gas Ltd is an integrated oil and gas exploration company which was founded in 2008 and is headquartered in Toronto, Ontario, Canada, with offices in the British Virgin Islands and Windhoek, Namibia. ECO is focusing its efforts on the new energy plays in Namibia. In the offshore of Namibia, ECO holds license blocks (Figure 4-5) (2213A and 2213B/Sharon License, 2012A/Cooper License, 2111B and 2211A/Guy License) which cover more than 25,000 square kilometers (6,177,000 acres). ECO also holds a transition license on the Skeleton Coast of Namibia that is both onshore Huab Basin and extends offshore Walvis Basin. This License #31 named "Daniel" includes Blocks 2114, 2013B and 2014B which comprise a total of 20,000 km^2 (Acres: 4,942,000). The directors of ECO have varied experience over the mining and petroleum exploration industries, including multi-commodity resource development, geotechnical analysis, and investment.

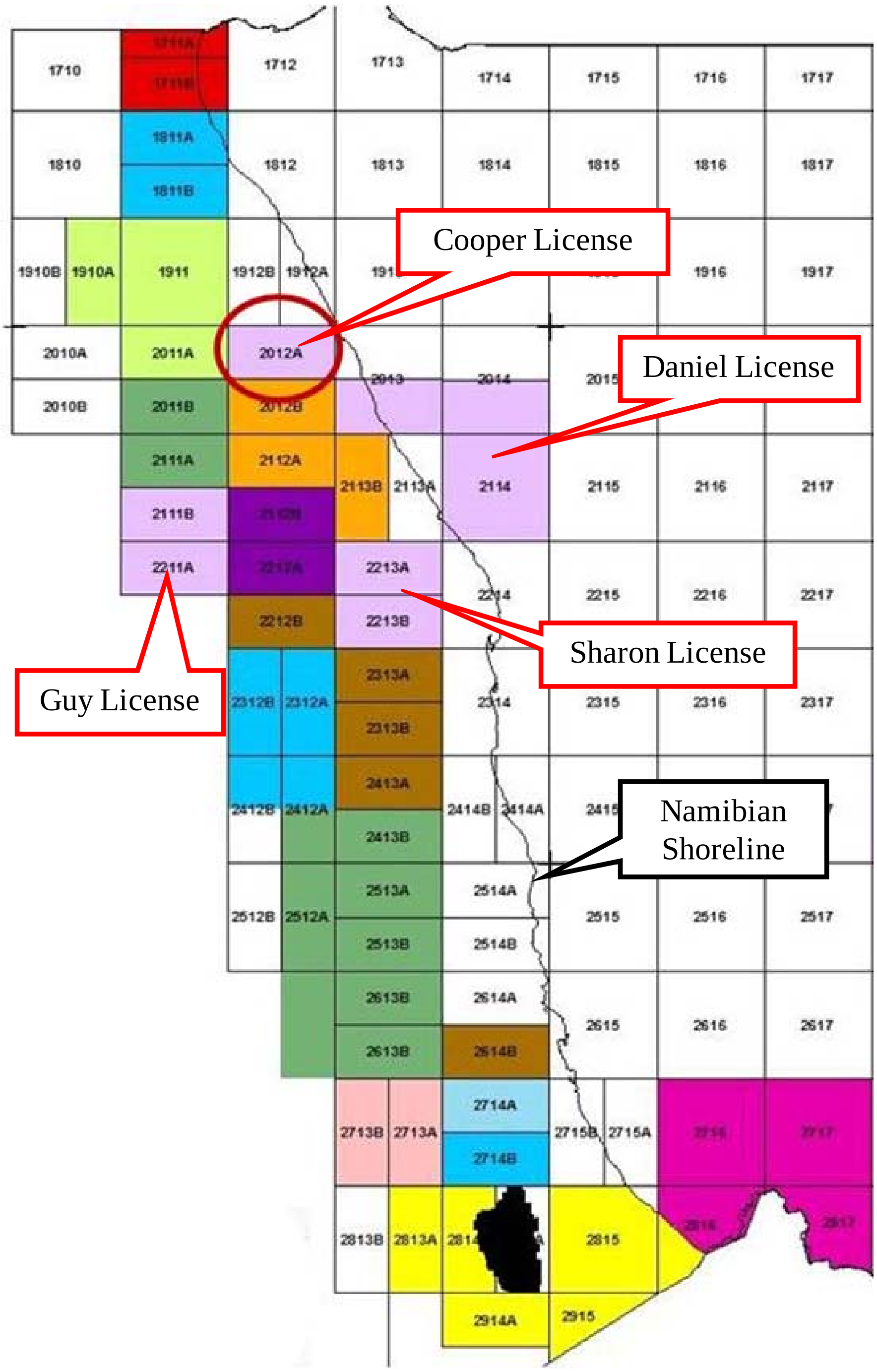


Figure 4-5 Eco Namibia Licenses

4.11 RISKS AND PROBABILITY OF SUCCESS

Due to the paucity of available data, the subject leads have a high level of risk. The database is limited to sparse 2D seismic data coverage and very few wells in the area. The lead section, Upper to Lower Cretaceous, had not been evaluated in detail in the wells drilled in the area. The quantification of risk or the chance of finding commercial quantities of hydrocarbons in any single lead for this play can be characterized with the following variables:

Structure: defined as the presence of a structure or stratigraphic feature that could act as a trap for hydrocarbons;
Seal: defined as an impermeable barrier that would prevent hydrocarbons from leaking out of the structure;
Reservoir: defined as the rock that is in a structurally favorable position having sufficient void space present whether it be matrix porosity or fracture porosity to accumulate hydrocarbons in sufficient quantities to be commercial; and
Presence of Hydrocarbons: defined as the occurrence of hydrocarbon source rocks that could have generated hydrocarbons during a time that was favorable for accumulation in the structure.

Table 4-1 shows the range of the Probability of Success (POS) or favorability that the above defined variables would occur. The Overall POS is the product of all four variables.

Table 4-1 Range of the Probability of Success (POS)

Probability of Success (POS)	Range % Min	Max	Comments
Structure	50	80	Seismic data indicates the presence of structures
Seal	20	50	Typical shale layers
Reservoir	10	50	Assumed to be similar to other areas in the world
Presence of HC	10	50	Production in Angola, Brazil, seeps
Overall	**0.1**	**10.0**	The product of the above factors

The predominant risks relate to the presence of an intact seal, the timing of source maturation, and the presence of an effective reservoir sufficient for the creation of commercial accumulations of oil and gas. This range of risk values is typical of leads to wildcat exploratory prospects where data is scarce.

4.12 FUTURE WORK PLANS AND EXPENDITURES

The total future budget over the next six years is estimated by ECO to be US$131,750,000. The first phase of exploration, during the first year from the effective date of the license agreement, included a desktop study that was estimated to cost US$550,000. ECO acquired and reviewed all available information and assessed that information to complete the study.

The second phase in 2014 and 2015 will include the acquisition of 500 square kilometers of 3D seismic data within the license block after potential drilling targets have been selected. The anticipated budget for this phase, which includes seismic acquisition, processing and interpretation, is US$5,200,000.

Phase three entails the drilling of an exploratory well which will be drilled to a depth that has will be defined from the 3D seismic interpretation. A rig will be contracted in 2015 and drilling will commence in 2015. The budget for exploratory drilling is US$122,750,000.

A two-year renewal of the license is planned for 2015 to continue the resource, production, and engineering assessments with a budget of US$750,000. The license will then be renewed for an additional two years to acquire an additional 500 square kilometers of seismic data and conduct additional geologic and target assessments with a budget of US$2,500,000.

4.13 MARKET AND INFRASTRUCTURE

Oil is being produced in the offshore of Angola to the north from multiple fields and gas has been produced from the Kudu Field to the south in the offshore of Namibia. The market and infrastructure near the license area will have to be developed as exploration continues.

5. GEOLOGY

5.1 STRUCTURE

During the Triassic Period, Africa and South America were connected as a part of Gondwana. Gondwana began to rift or spread apart during the Jurassic Period and the South Atlantic margin started to open. The Namibian offshore basins were formed in this passive margin during the opening of the South Atlantic and the continental break up. The basins were further developed while the continents continued to drift apart from each other during the Cretaceous Period until Recent time. The opening and the rift to drift configuration of the South Atlantic margin is depicted in Figure 5-1, from Versfelt (2010). The yellow box highlights Namibia along with the Santos Basin in Brazil, which is considered an analogous play area. A detailed map of the opening of the South Atlantic in the area of interest in offshore Namibia and the Santos Basin in Brazil is shown in Figure 5-2. The Santos Basin has had a number of commercial hydrocarbon discoveries recently and could be considered the mirror image of the Walvis Basin in Namibia.

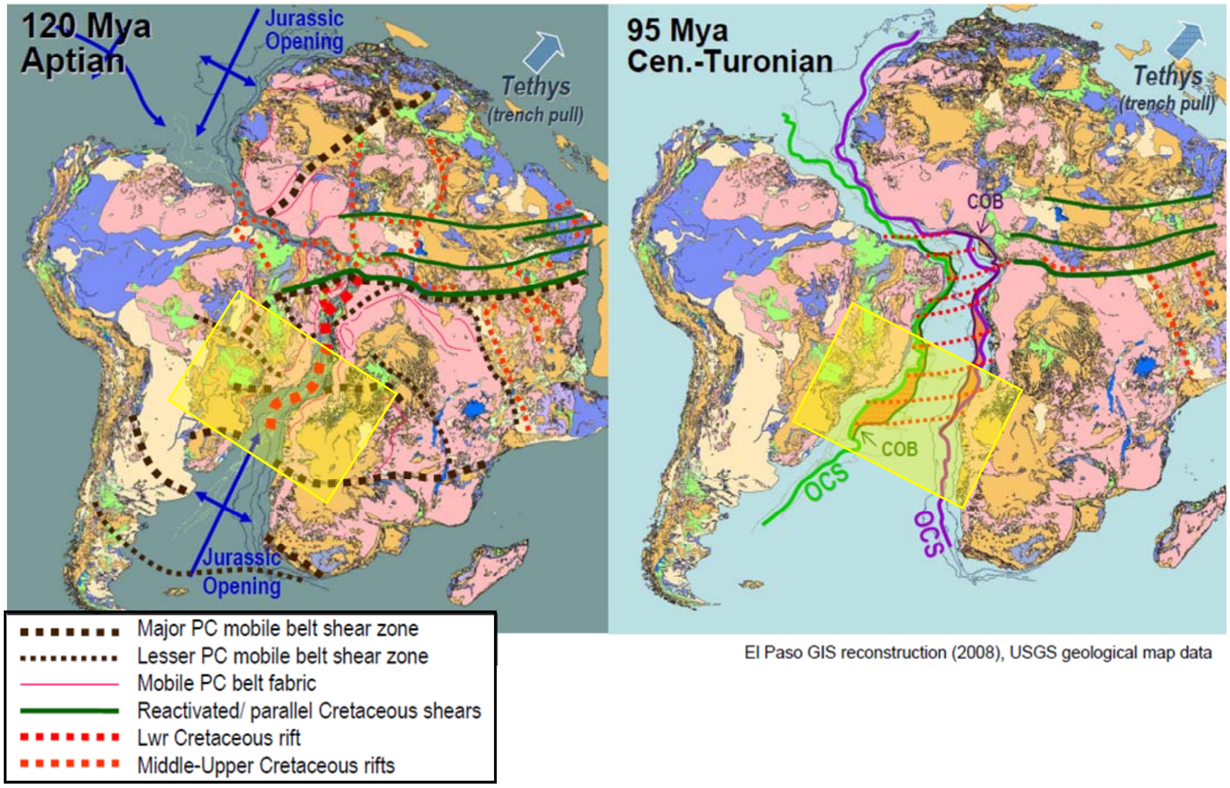


Figure 5-1 Diagram of the Opening of the South Atlantic Margin

(Versfelt, 2010) Highlighted is Namibia and Brazil

Cretaceous to Tertiary sediments were deposited over early Cretaceous rift sediments to form the basin system that extends along offshore Namibia. A distinct hinge line separates the area of thin late drift sediments from the zone of rapid sediment thickening to the west. The hinge line also marks the wedge-out of the syn-rift sediments. The rift zone is characterized by tilted blocks bounded mostly by landward dipping normal faults. This series of tilted blocks runs the entire length of the margin. The rift section passes westward into a thick wedge of westward dipping reflectors. These seismic reflectors are thought to be volcanic and precursors to oceanic spreading. The reflectors overlie the western edge of the syn-rift section and pass westward into oceanic basement.

The sedimentary basins in offshore Namibia are illustrated in Figure 5-3 where the area of interest is within the Walvis Basin.

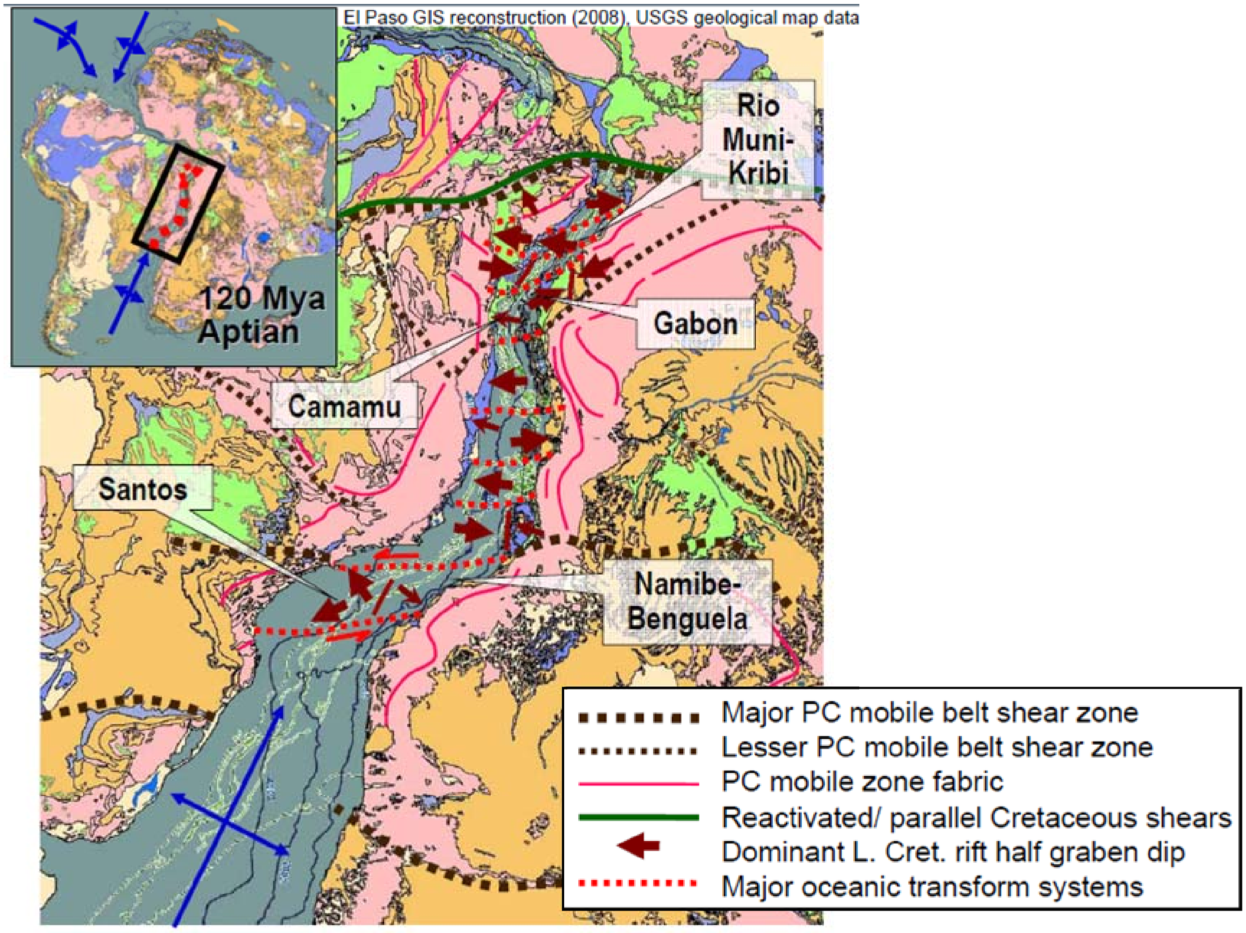


Figure 5-2 Close-up of the Subject Area during the Opening of the South Atlantic Margin
(Versfelt, 2010)

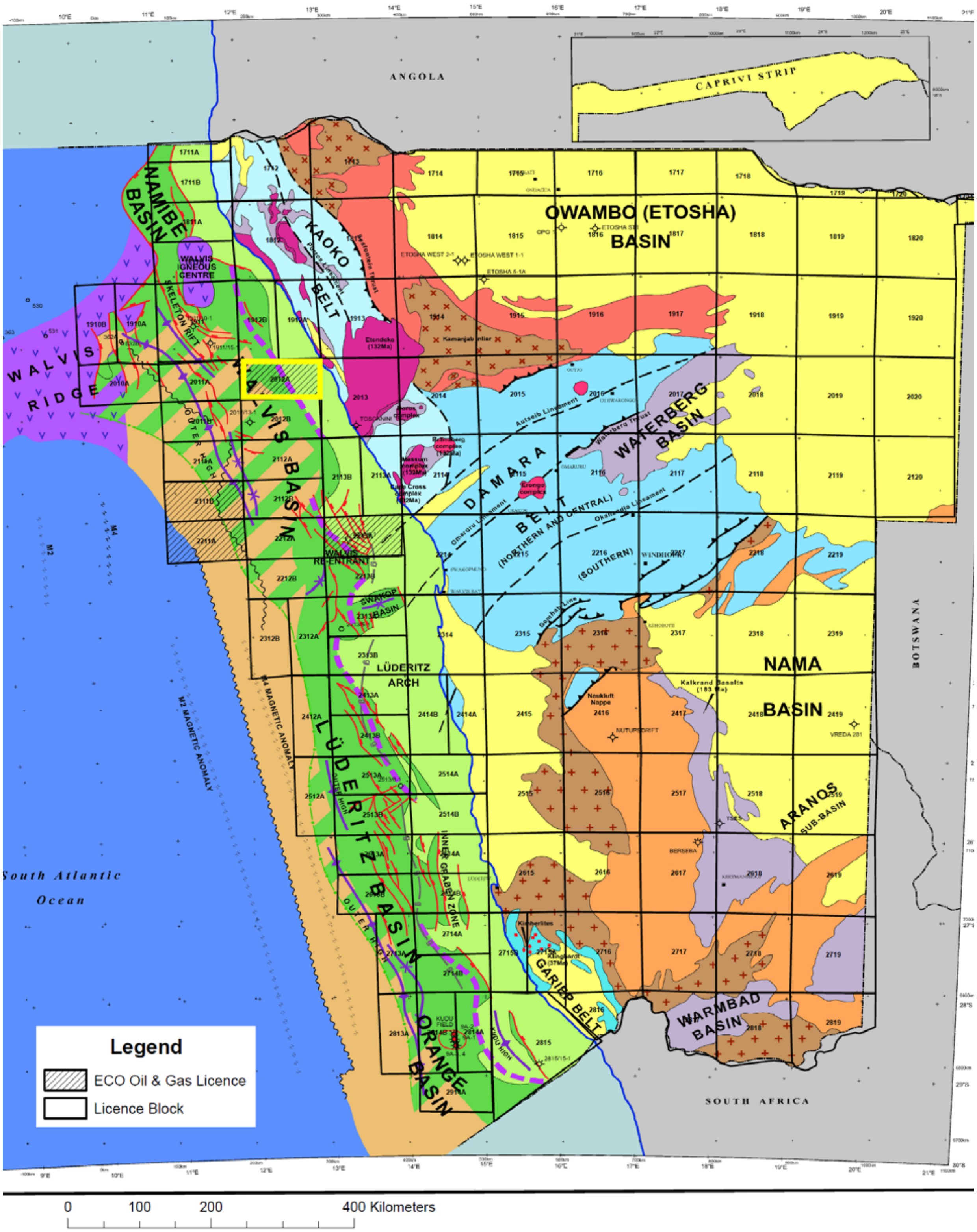


Figure 5-3 Sedimentary Basins in Offshore Namibia
(Bray, Lawrence, Swart, 1998) Yellow box highlights Cooper Block.

5.2 STRATIGRAPHY

The basin system in offshore Namibia consists of four tectono-stratigraphic units - Permo-Carboniferous pre-rift Karoo section, Early Cretaceous syn-rift section, Late Barremian/Cenomanian early drift section, late drift section - separated by three unconformities - base rift unconformity, base drift unconformity, Tertiary unconformity. Figure 5-4 is a generalized stratigraphic chart of the area showing age, rift stage, stratigraphy, oil and gas shows, and potential source rock intervals. The early Cretaceous syn-rift section is comprised of aeolian sandstones and basalts. The uppermost part of this section is penetrated at the Kudu Field in southern offshore Namibia. The base drift unconformity, which separates the early Cretaceous syn-rift section from the late Barremian/Cenomanian age early drift section, is the transition from non-marine to marine sediments. The late Barremian/Cenomanian age early drift section consists of marine claystone sequences which include organic rich intervals. The late drift section is Turonian to Recent in age and is the main part of the basin fill. This section is dominantly a progradational sequence and is divided into the lower and upper units by the Tertiary unconformity (Bray, Lawrence, Swart, 1998).

5.3 PETROLEUM SYSTEM

In a frontier exploration area, any information on the petroleum system is applied or modeled to the extent possible. However, there is usually very limited data of this sort in sparsely explored areas and consequently, petroleum companies primarily target anticlines and fault traps for exploratory drilling.

Petroleum systems are based on the factors affecting hydrocarbon accumulations including[4]:

1. trap (a structure or limit to the quality of the reservoir rock that is capable of holding hydrocarbons) – this block has at least five structures.
2. reservoir rock (one or more rock layers that has sufficient porosity and permeability to store hydrocarbons) – the Cretaceous strata are expected to be sand and shale with sufficient porosity and permeability to store hydrocarbons.

[4] Magoon, 1988

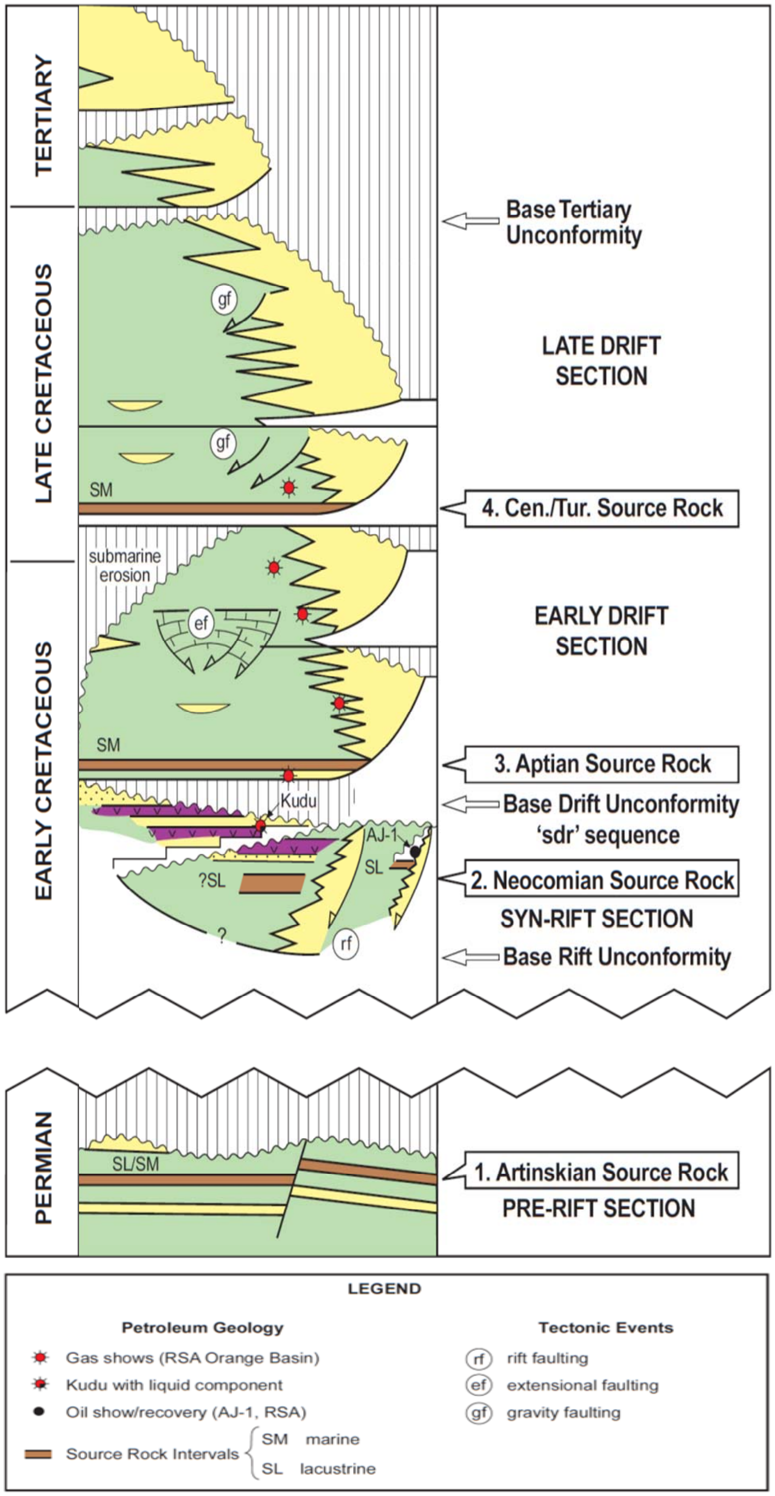


Figure 5-4 Generalized Stratigraphic Chart of Offshore Namibia
(Bray, Lawrence, Swart, 1998)

3. source rock (a rock layer in the region that has sufficient organic content to provide for hydrocarbons) – the Cenomanian – Turonian source rock (Number 4 in Figure 5-4) was noted by Shell to be an excellent source rock.
4. maturation (the burial of the source rock sufficient to generate hydrocarbons from the organic material within the source rock) – the Cenomanian–Turonian source rock (Number 4 in Figure 5-4) should be in the early oil window at this time.
5. migration (the path of movement of the generated hydrocarbons from the source rock to a trap), seal (a layer that is impermeable to hydrocarbon and prevents the hydrocarbon from escaping the trap) – faults that would act as migration pathways have been identified on the seismic data. These faults extend from the Cenomanian–Turonian source rock (Number 4 in Figure 5-4) up into the lead structures.
6. timing (the events must occur in the correct order to create and preserve a hydrocarbon accumulation) – the generation of hydrocarbons would have occurred recently, most likely after the structures were formed.

5.4 SOURCE ROCKS

Shell, in their Shark Well Proposal, noted that 270 meters of good to excellent oil prone source rock was logged in the Block 1911/ 10-1 Well drilled by Norsk Hydro in 1995. These included Turonian shales (W4 Group) seen at a depth of 3,334 to 3,646 meters and Cenomanian shales (W3 Group) encountered at a depth of 3,646-3,856 meters. The deposition of these sediments coincided with the mid-Cretaceous ‘oceanic anoxic event’.

Early Aptian source rock[5] was deposited when restricted marine conditions prevailed. The Aptian section in the Kudu wells contains a marine oil prone source rock approximately 140 meters thick. This same source is located on Cooper Block, Figure 5-5, down-dip to the leads. The HRT Wingat well drilled approximately 210 kilometers (130 miles) south of the Cooper Block also identified a well-developed Aptian source rock, which was reported to be in the oil generating window. The oil from this well was described as light oil at 41° API with a GOR of 1,193 scf/bbl. Oil of 40 ° API with associated gas is the expected hydrocarbon type to be found

[5] Oil & Gas Journal – August 1998 – R. Bray, S. Lawrence, R. Swart

in these leads due to the Turonian–Cenomanian aged source rock and the Aptian source rock being just within the hydrocarbon generating window. A preliminary study by PGS based on geothermal gradients derived from the existing well information indicates that the Turonian–Cenomanian aged source rock could be in the oil window in the western part of the Cooper Block and the Aptian aged source rock could be within the oil window throughout most of the block.

The Sasol well identified source rocks in the Upper Cretaceous Santonian to Cenomanian interval from 3,285 to 3,657 meters and in the Turonian – Cenomanian section a very good oil-prone source rock occurred from 3,500 to 3,650 meters.

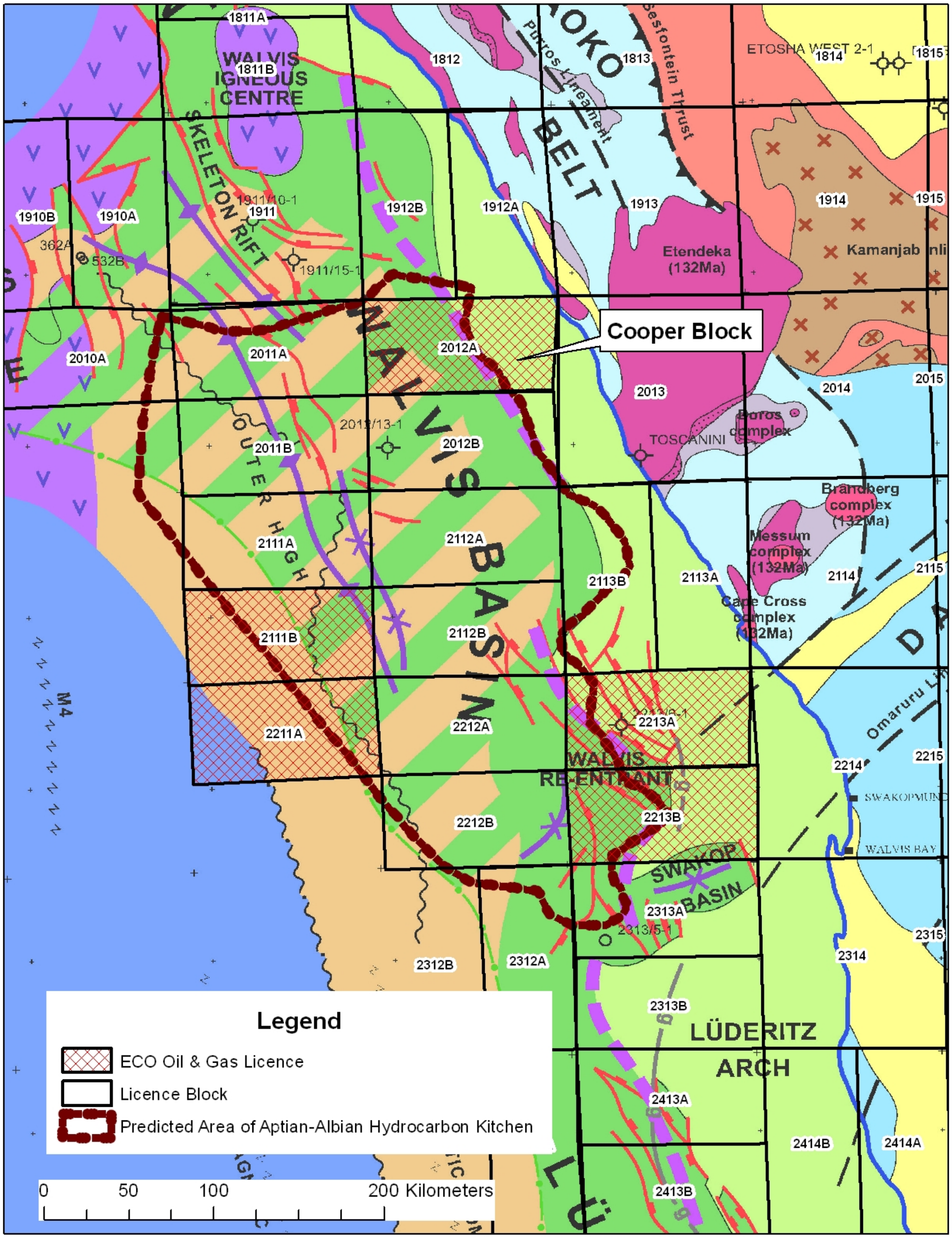


Figure 5-5 Extent of Albian-Aptian Source Rock

5.5 GENERATION AND MIGRATION

Oil would be generated from the Turonian and Cenomanian shales below and downdip of the lead traps and would migrate along faults that intersect both the source rock at depth and the lead section. These faults are not observed to have reached the ocean bottom.

5.6 RESERVOIR ROCKS

The Sasol 2012/13-1 well, drilled to the south of Cooper block, found deep-sea turbidite sands in the Maastrichtian to Campanian (Cretaceous) section. This interval occurred from 2,660 to 2,994 meters and was 334 meters in gross thickness. Sidewall core samples had a porosity of 21%.

The HRT Wingat-1 well found several thin bedded oil saturated sands found with 41 degree API oil with a 1,193 GOR within the Cretaceous section. The Murombe-1 well encountered 36 meters of net sand with an average porosity of 19%.

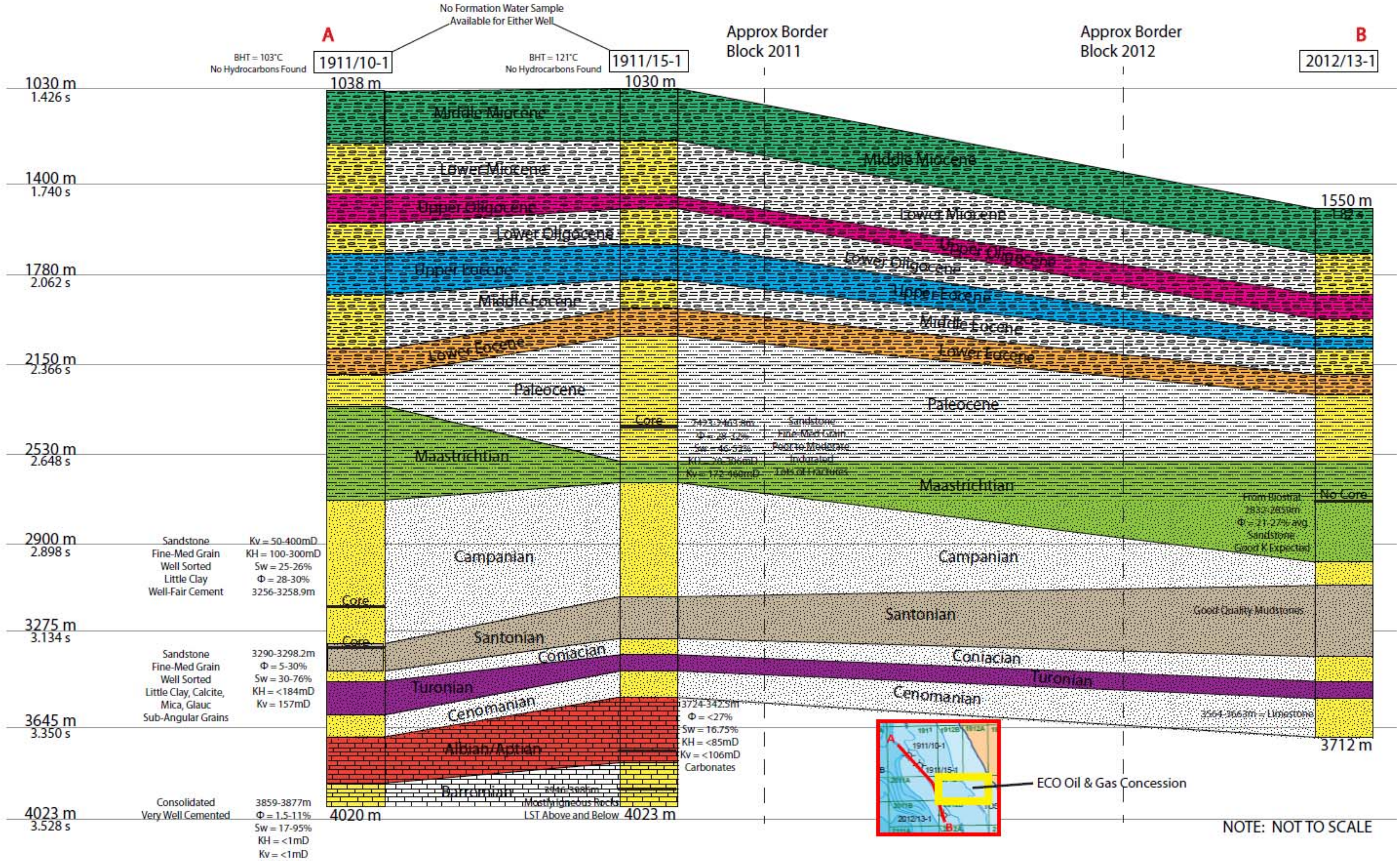


Figure 5-6 Cross-section through Wells near Cooper Block

5.7 TRAPS AND SEALS

Structural and fault traps as well as stratigraphic traps with shale layers as a seal form the leads identified on the 2D seismic data. These seals have not been observed in the few wells drilled in the area and the structures are based on seismic time maps.

5.8 ANALOGOUS FIELD

The Santos Basin in Brazil consists of drift and rift sections that are of similar age to the drift and rift sections of offshore Namibia. Volcanism was present during formation, much like the early Cretaceous syn-rift section in Namibia. Albian/Aptian carbonates are also present in the Santos Basin like in the early drift section in Namibia (UFRJ and Gustavson, 1999). The Tupi Oil Field in the Santos Basin, discovered in 2006, is estimated to contain up to 8 billion barrels of recoverable oil (Fessler, 2011).

5.9 EXPLORATION HISTORY

The offshore of Namibia is an underexplored area with only 20 shallow shelf wells drilled in an area of more than 500,000 square kilometers (Figure 5-7). Five of these wells are located in the southern part of the offshore area in Kudu Field which was drilled in1974 and is the only discovery so far. Offshore leases were first offered in 1968 and 1972 and by 1975 approximately 33,000 line kilometers of 2-D seismic data were shot, but only one well was drilled.[6] A United Nations mandate in 1976 voided all concessions granted to foreign companies by the government of South Africa, which had control over the Namibian area, and for the next 10 years there was virtually no oil or gas activity until in 1987 and 1988. At that time, two more wells in Kudu were drilled for Namcor. In 1989 Intera, ECL, and Halliburton Geophysical Services Inc. shot a 10,600 line kilometer regional speculative seismic survey off Namibia. This was followed up with an infill survey of some 3,500 line kilometers and additional speculative surveys shot in early to mid-1990 by TGS and Western. A total of six wells have been drilled in the vicinity of

[6] NAMIBIA, PRACTICALLY UNEXPLORED, MAY HAVE LAND, OFFSHORE POTENTIAL; Apr 8, 1991; M.P.R. Light, H. Shimutwikeni

Cooper Block. The 1911/15-1 well was drilled in early 1994 and the 1911/10-1 well was drilled in early 1995 by Norsk Hydro Namibia. The Ranger Oil Namibia Ltd 2213/6-1 was drilled in early 1995, the Sasol 2012/13-1 well located to the south of Cooper Block was drilled in early 1997 and in 2013 HRT drilled 2 wells in block 2212A the Wingat-1 and the Murombe-1.

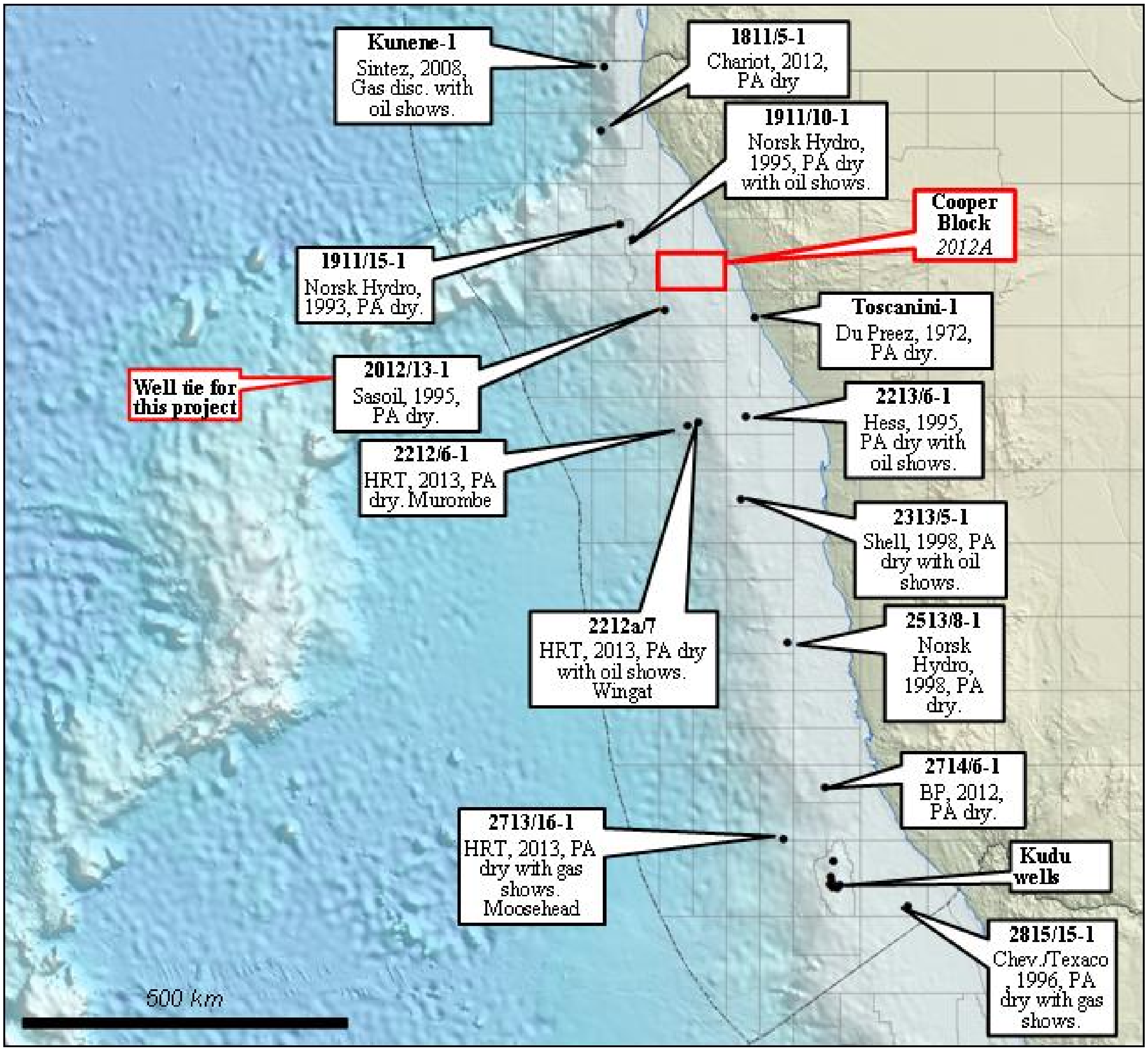


Figure 5-7 Offshore Namibia Well Locations

Recently, Offshore Namibia is attracting significant international interest as an emerging oil and gas province in southwest Africa. Several Blocks have been licensed in the past year with Pancontinental Oil & Gas NL having selected approximately 17,295 square kilometers covering Blocks 2012B, 2112A and 2113B. HRT Participações em Petróleo S.A. acquired 5,278 square kilometers of 3D seismic over their blocks 2112B and 2212A which are located approximately 120 kilometers south of the Cooper Block. Further south, Serica Energy Namibia B.V licensed Blocks 2512A, 2513A, 2513B and 2612A which covers an area of approximately 17,400 square kilometers and Spectrum, in partnership with CGGVeritas and the National Petroleum Corporation of Namibia (NAMCOR), has commenced a new 2D multi-client seismic survey of around 7,000 km covering both held and open blocks.

In 2012, Chariot drilled the Tapir South-1 well to a depth of 4,879 meters north of the Walvis Ridge and found wet Upper Cretaceous sandstones. Chariot also drilled a well to the south of Cooper in block 2714A and encountered source rocks in the Cretaceous section. In 2013, HRT drilled 2 wells in block 2212A the Wingat-1 and the Murombe-1. The Wingat well had oil shows and found source rocks reportedly in the oil window. In block 2713 northwest of KUDU field, HRT drilled the Moosehead-1 which encountered 100 meters of carbonates and ‘wet’ gas shows were seen along with a well-developed Aptian age source rock. Oil seeps have been observed in the offshore area near the Cooper Block.

5.10 CONTRACT AREAS

The contract area is located in the offshore of Namibia, totaling 5,000 square kilometers. Exploration License Agreement number 0030 for the Cooper Block is made with the *Republic of Namibia Ministry of Mines and Energy*, dated March 14, 2011 effective until March 14, 2015. Table 5-1 lists the location coordinates of the license area while Figure 5-8 shows the location of the license area.

Table 5-1 Coordinates of Cooper Block

Label	**Latitude**	**Longitude**
A	20° 00’ 000”	12° 00’ 000”
B	20° 30’ 000”	12° 00’ 000”
C	20° 30’ 000”	13° 00’ 000”
D	20° 00’ 000”	13° 00’ 000”

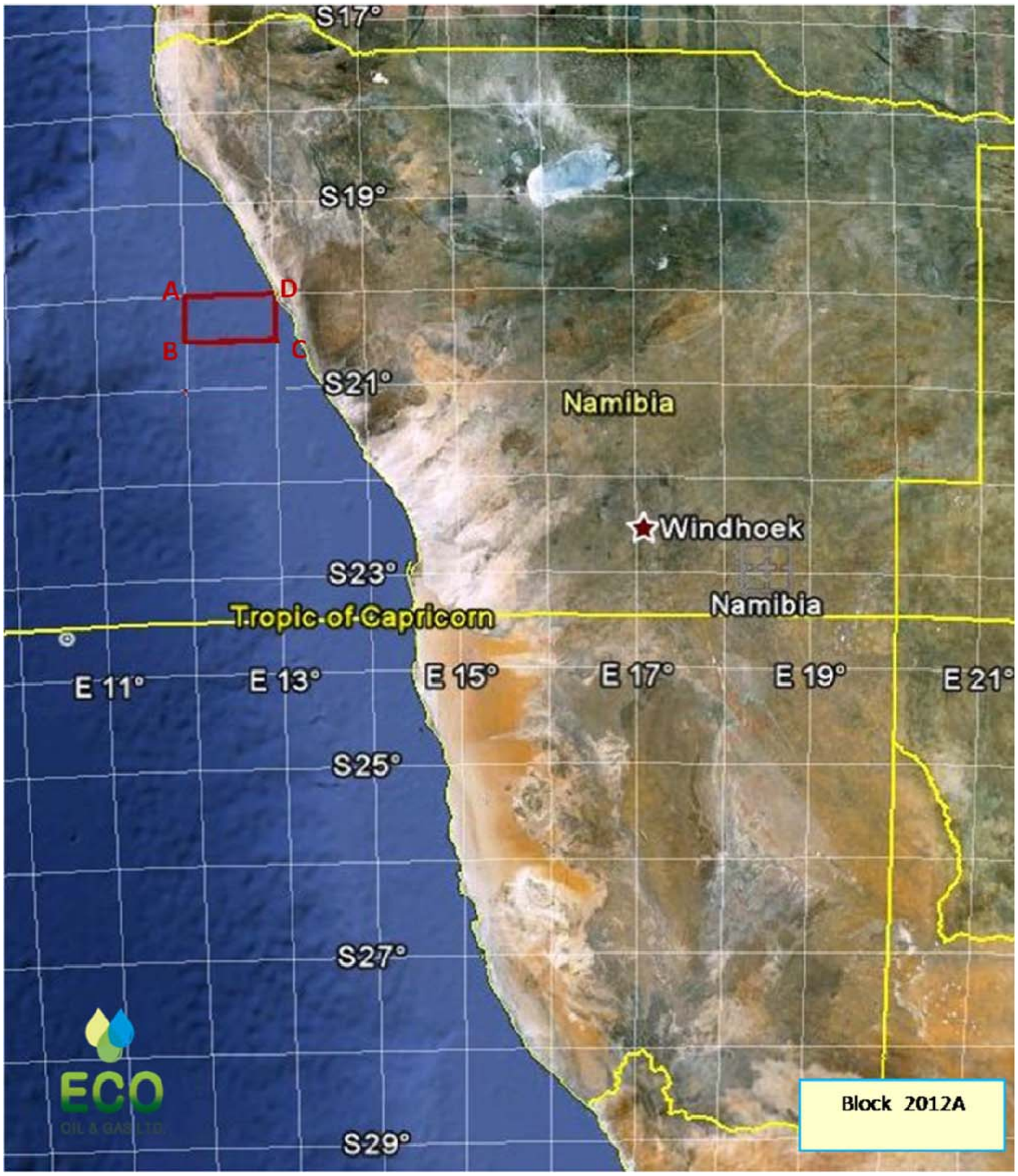


Figure 5-8 Location of Cooper Block

5.11 MINIMUM WORK OBLIGATIONS

The minimum work obligations and expenditures for the Cooper Block license are summarized in Table 5-2 according to the *Petroleum Agreement Between The Government of the Republic of Namibia and ECO Oil and Gas Namibia (PTY) LTD.*:

Table 5-2 Minimum Work Obligations

Minimum Exploration Work **INITIAL EXPLORATION PERIOD (4 YEARS)**	*Minimum Exploration Expenditure*
PHASE I DESKTOP STUDY – YEAR 1 Acquire and review all available information for this license based on information in Namibia and through internationally based research libraries including available geophysical studies, local and regional well logs and basin interpretation. Assess information and complete the Company's interpretation and selection of regional targets and definition of 3D parameters.	US $550,000
PHASE II SEISMIC ACQUISITION SURVEY – YEARS 2 & 3 The Company will complete a survey of 500 square kilometers of 3D Seismic with each license after regional target selection.	US $5,200,000
PHASE III DRILLING EXPLORATORY WELL – YEARS 3&4 Assuming a target has been defined after interpretation of the 3D survey, a well will be committed to be drilled on each license. The well will be drilled to depth to intersect the targets determined in the 3D processing. Based on the current processing schedule, the company will contract a rig in year three and drill in year four. If the company is awarded more than one license it is anticipated the same rig would be used for the committed drilling and our timing for completion of drilling the wells would be adjusted accordingly.	US $122,750,000
IST RENEWAL EXPLORATION PERIOD(2 YEARS)	
PHASE IV RESOURCE ASSESSMENT & PRODUCTION ASSESSMENT - YEAR 5	US $250,000
PHASE V OFFTAKE/PRODUCTION ENGINEERING ASSESSMENT & PLANNING - 1ST RENEWAL PERIOD, YEAR 6	US $500,000
SECOND RENEWAL EXPLORATION PERIOD(2 YEARS)	
PHASE VI ADDITIONAL SEISMIC ACQUISITION SURVEY OF 500 KM^2 **, GEOLOGICAL ASSESSMENT AND TARGET ASSESSMENT -, YEARS 7 & 8**	US $2,500,000

5.12 LEADS

The interpretation of over 1,450 kilometers of 2D seismic data in offshore Namibia acquired by TGS in late 1992 over Cooper Block has produced seven leads. The leads are called A, B, C, D, Flat, Campanian Fan, and Albian Channel. Leads A, B, C, D, and Flat are interpreted as structures with associated faults and Leads Campanian Fan and Albian Channel are interpreted to be stratigraphic traps (Figure 5-9). The faults in the structural leads are interpreted to extend down into the Turonian-aged source rock. The estimated reservoir parameters of the leads are discussed in Section 6.2.

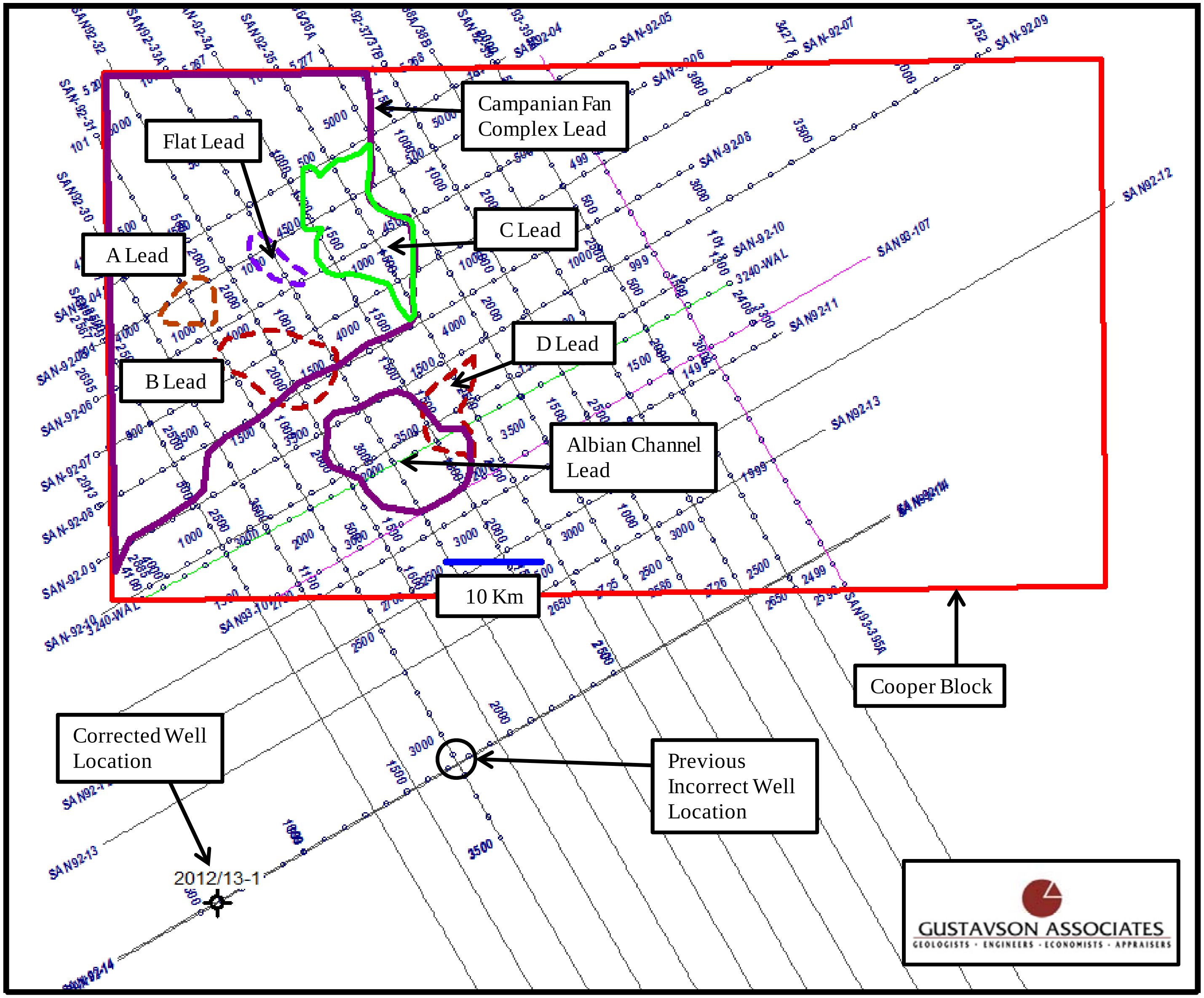


Figure 5-9 Locator map for Leads on Cooper Block

5.12.1 Campanian-Age Leads A, C, Flat, and Fan Complex

There are four leads identified from the seismic data in the northwest corner of the Cooper Block in Campanian-age strata. These are A Lead, C Lead, Flat Lead, and Fan Complex Lead (Figure 5-10). This feature was interpreted by PGS as being Maastrichtian in age, but Gustavson has interpreted this interval to be Campanian in age based on the tie with the Sasol well. In the previous report, Gustavson had identified the A, C, and Flat Leads as being Oligocene- through Eocene-aged which was based on the incorrect Sasol well location.

The Campanian Fan horizon includes Leads A, C, and Flat (Figure 5-10) and appears to dip generally to the southwest but appears to be a complicated interval. The complexity is interpreted as sediment deformation and the nature of this interval is shown on the seismic line that defines Lead A (Figure 5-11). The deformation may be due to slumping, sediment loading, differential compaction, turbidite deposition or other gravity processes. To the east the deformed interval is interpreted to be absent.

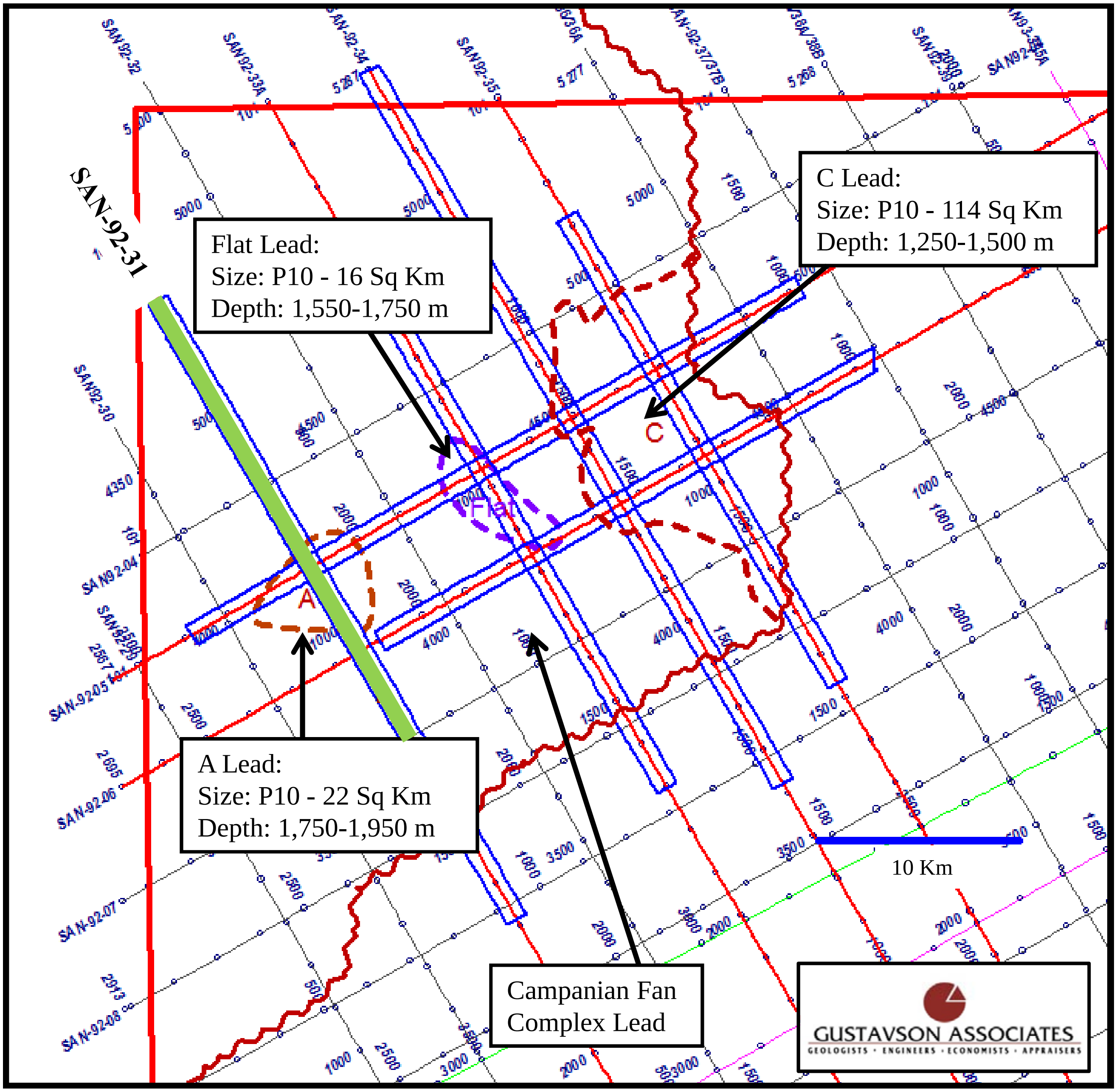


Figure 5-10 Map Showing the Locations of the Campanian Age Cooper Block Leads and Seismic Data Base

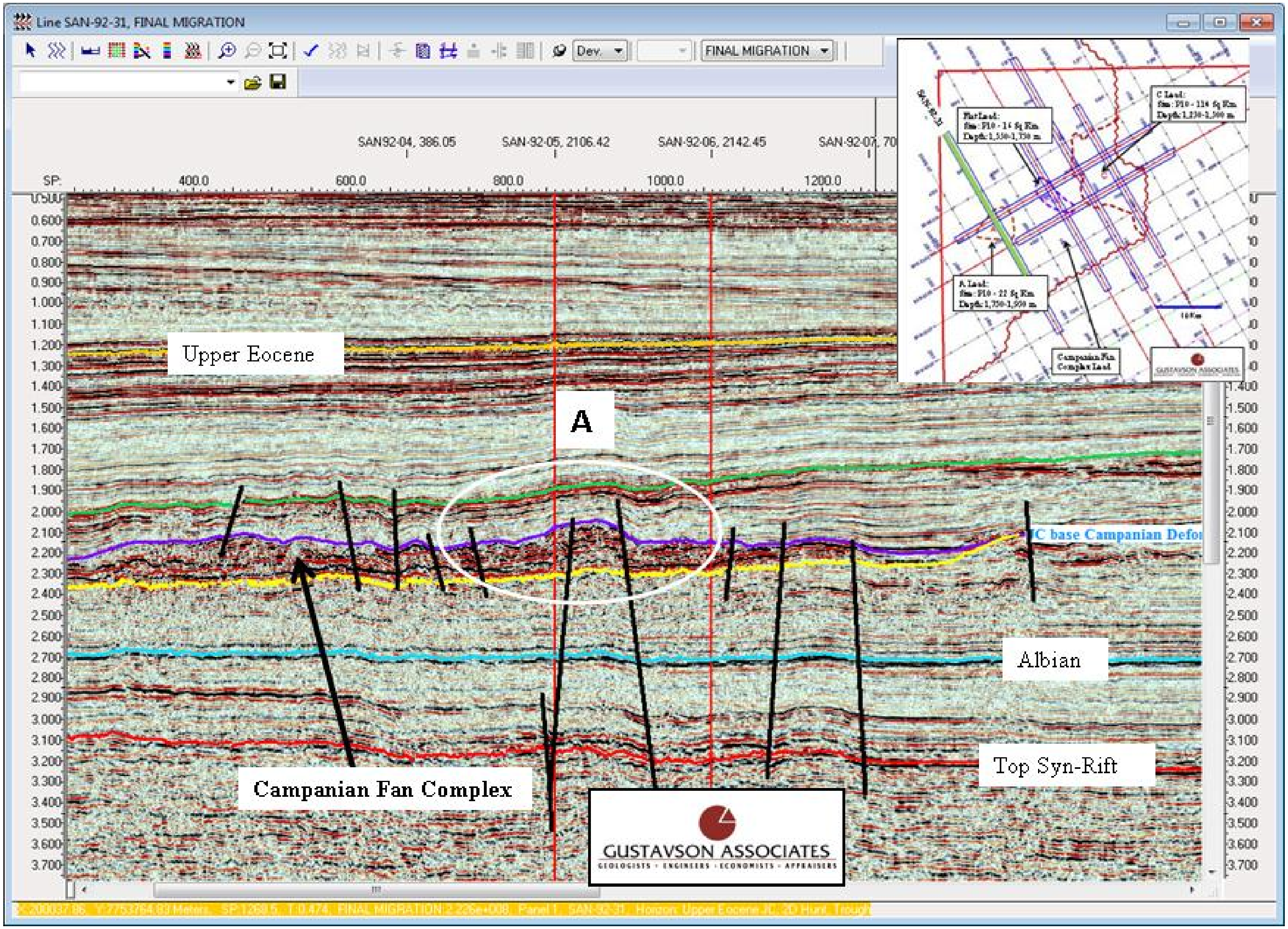


Figure 5-11 Line SAN-92-31 Showing the A Lead within the Campanian Fan Complex and Location Map

Figure 5-12 is a time structure map on the Campanian horizon and shows the location of Leads A, C, and Flat.

The isochron and isopach maps of the Campanian interval show the relationship of each of the three Campanian leads to the thick areas within the fan complex zone (Figure 5-13 and Figure 5-14). The isopach map was used to estimate the gross thickness of Leads A, C, Flat and Campanian Fan.

Leads A, C and Flat are indicated on seismic line SAN-92-05 (Figure 5-15). These leads are within the same Campanian age seismic interval.

Seismic lines that define these three leads are shown as Figure 5-16, Figure 5-17, Figure 5-18, Figure 5-19, and Figure 5-20.

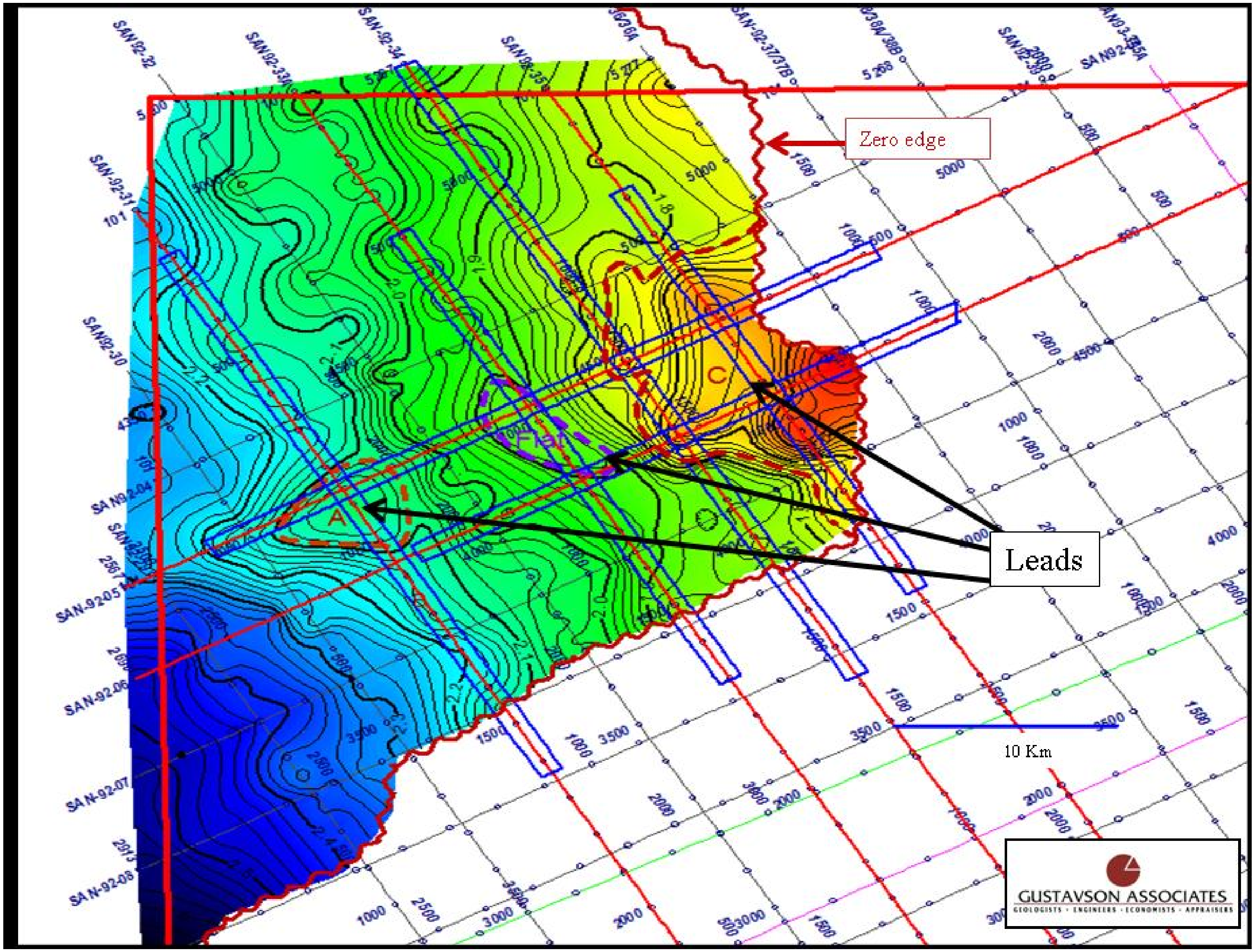


Figure 5-12 Cooper Blocks Leads A, Flat and C on Campanian Time Structure Map

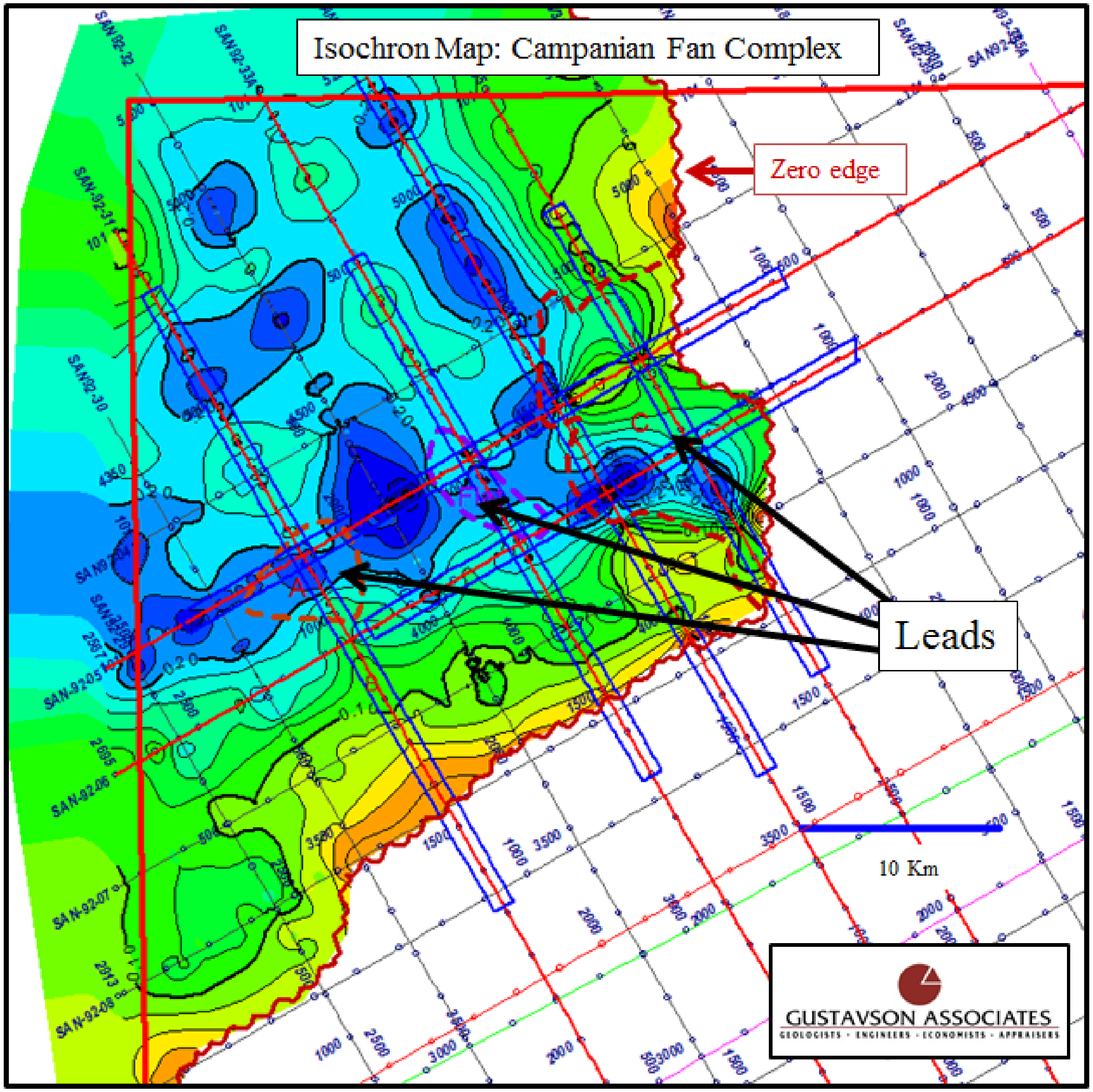


Figure 5-13 Cooper Block Leads on Campanian Isochron Map

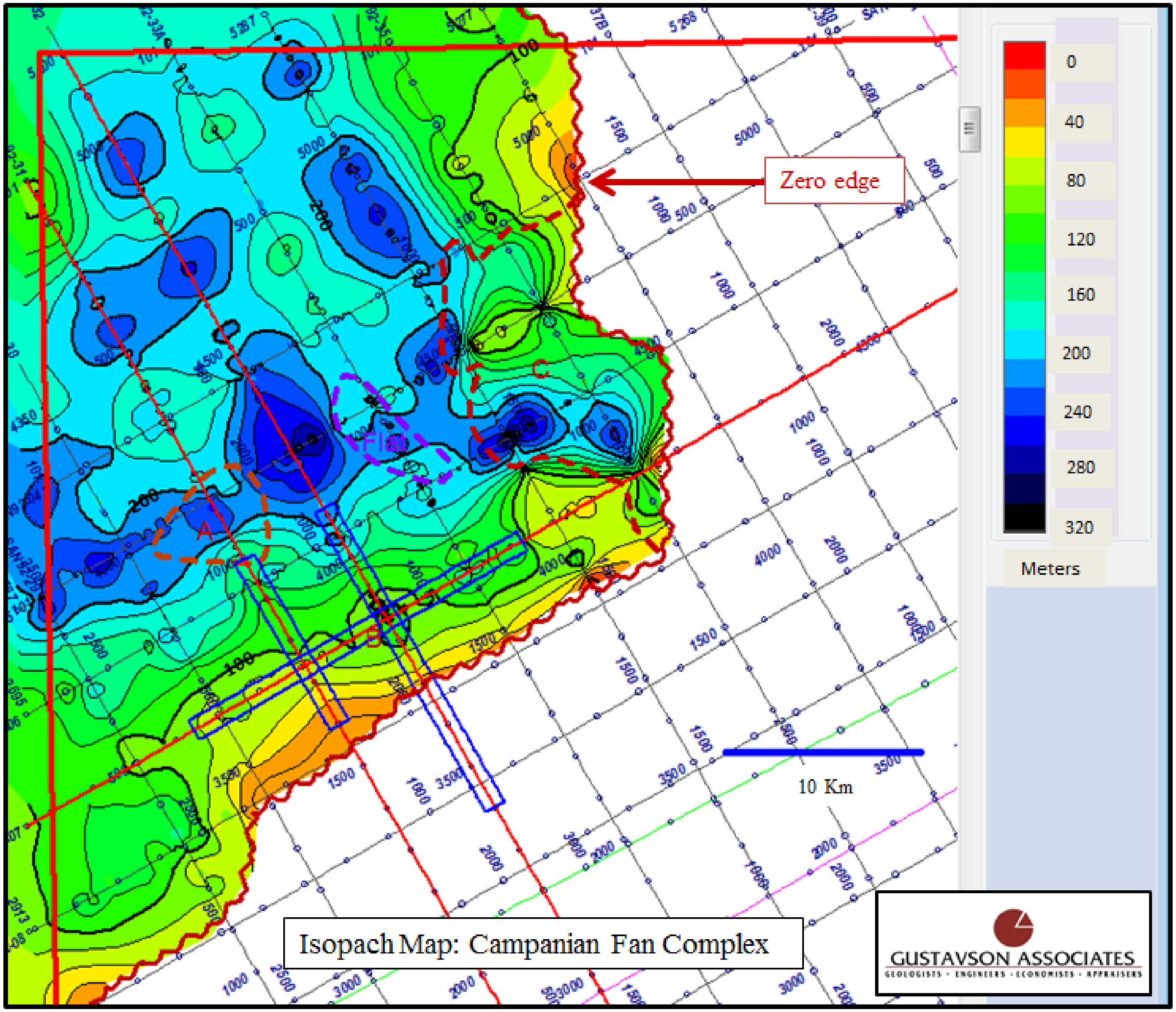


Figure 5-14 Cooper Block Leads on Campanian Isopach Map

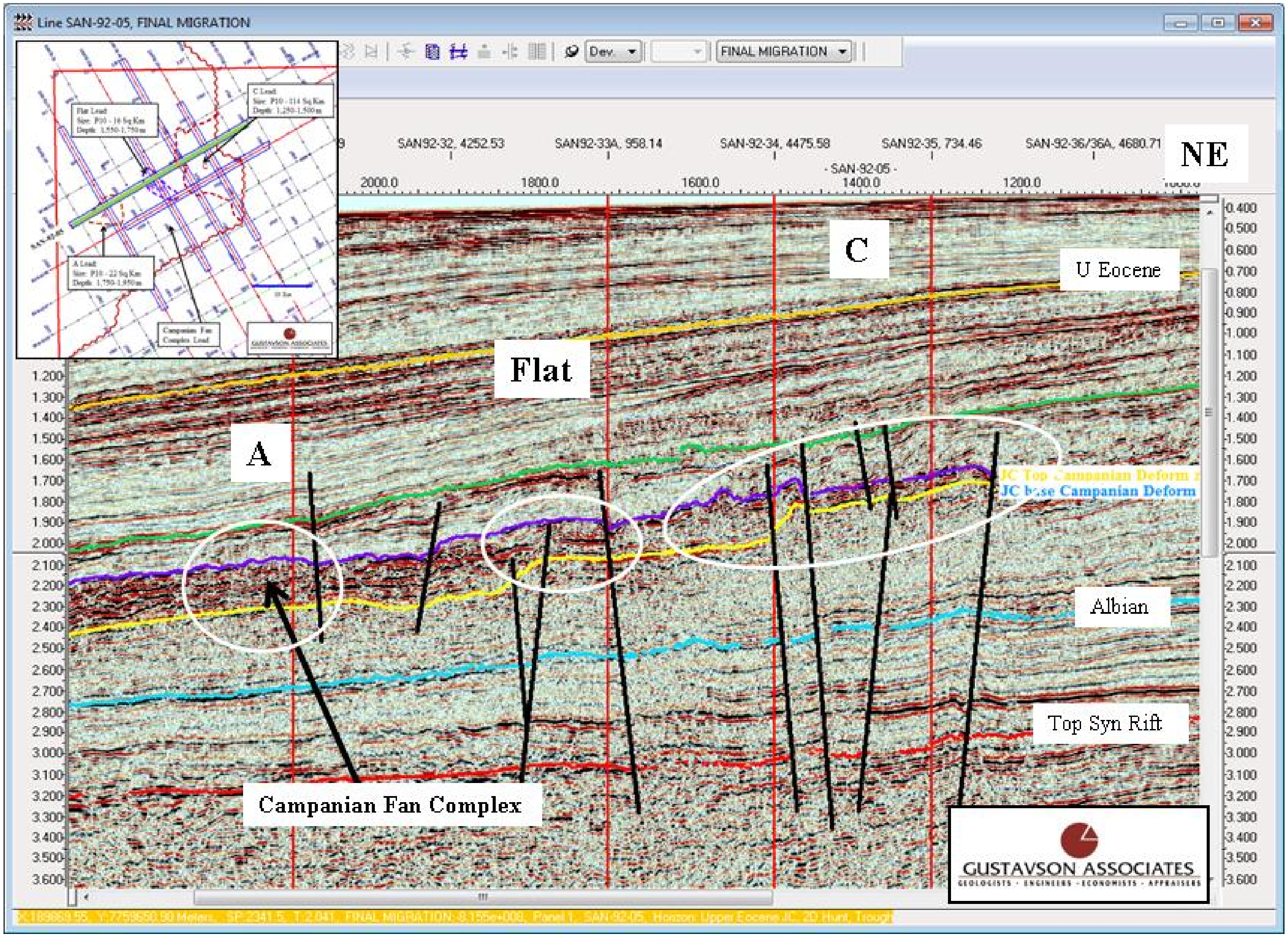


Figure 5-15 Seismic Line 92-05 Showing Leads A, C, and Flat and Location Map

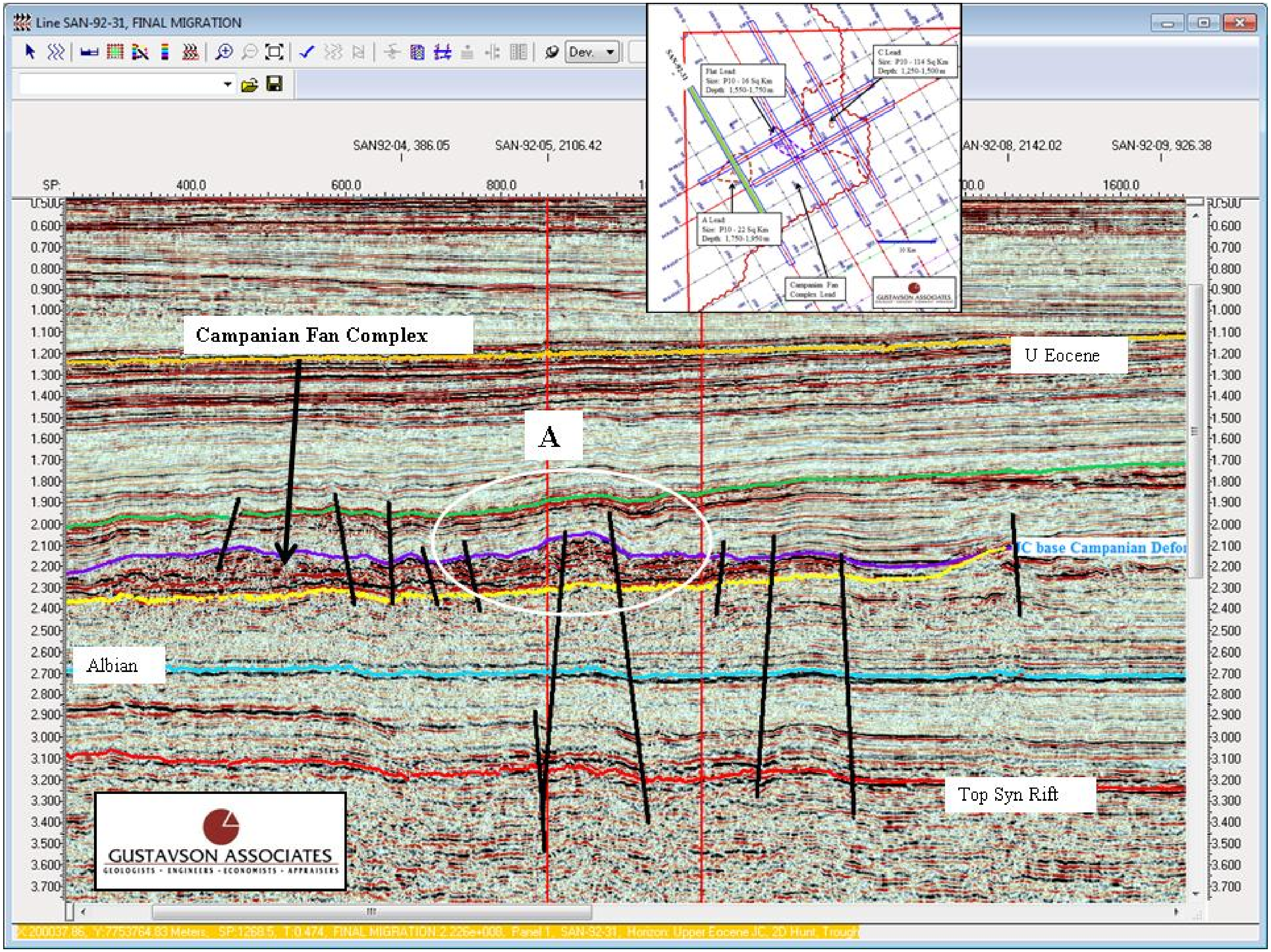


Figure 5-16 Seismic Line SAN-92-31 Showing Lead A and Location Map

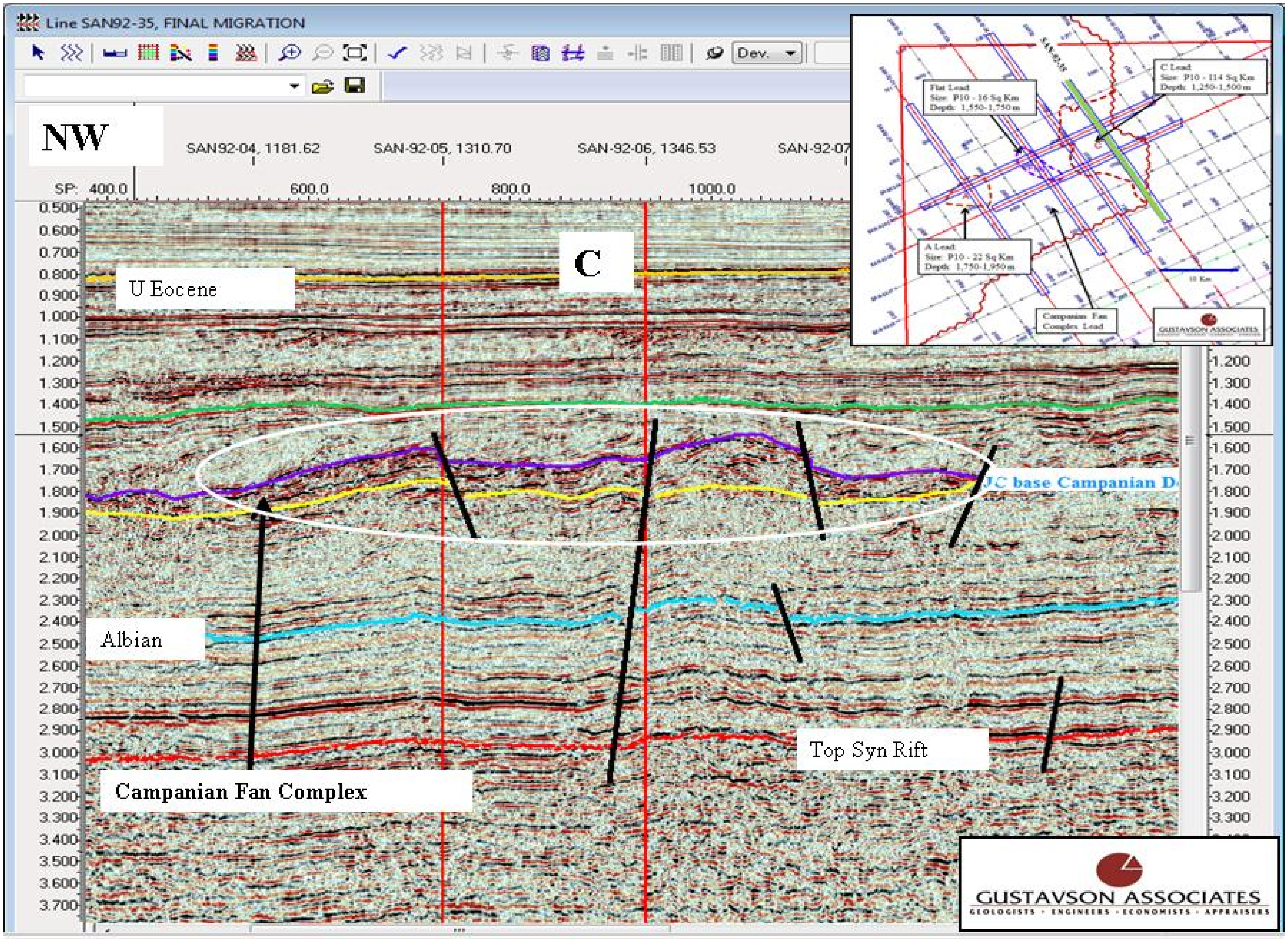


Figure 5-17 Seismic Line SAN-92-35 Showing Lead C and Location Map

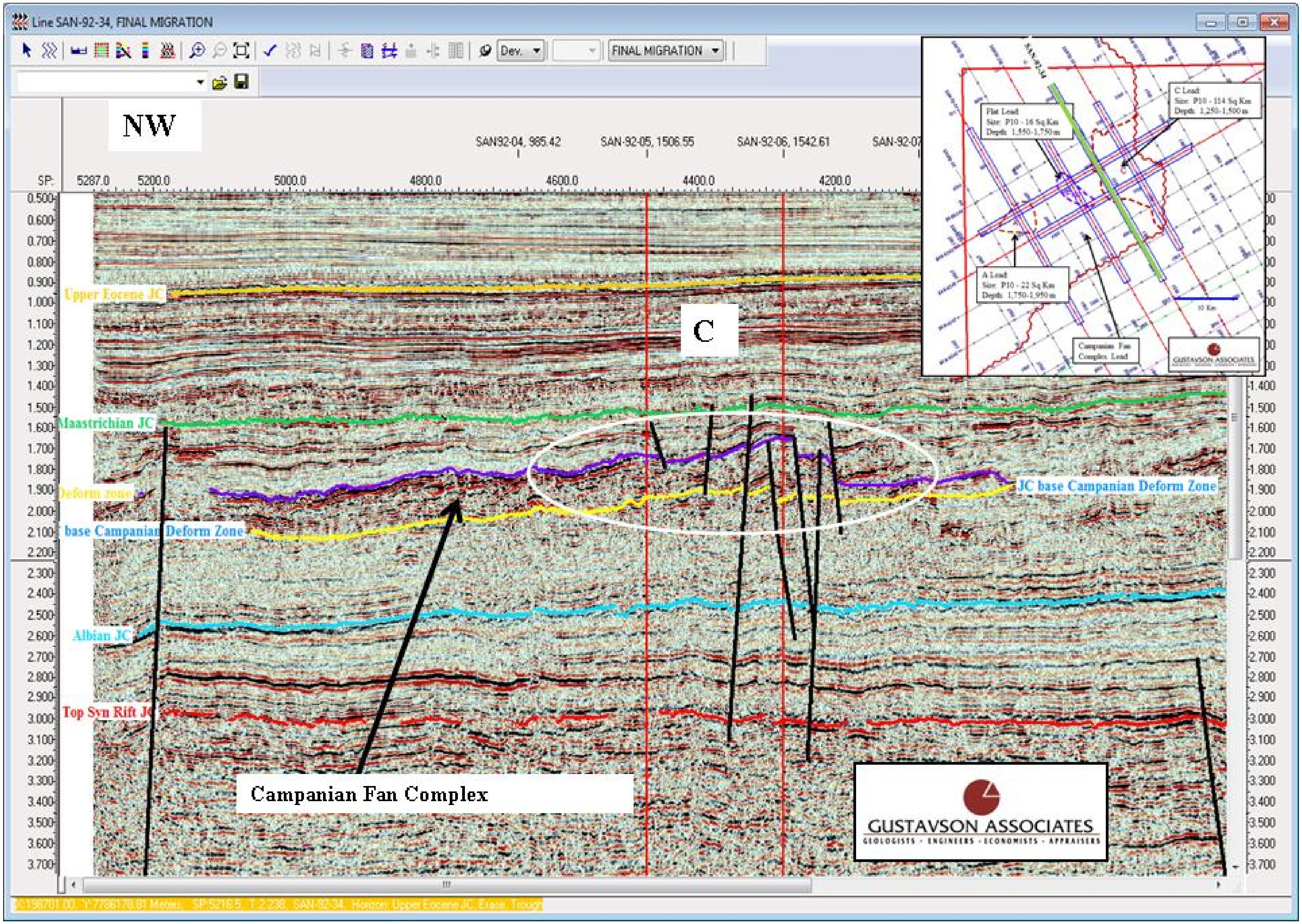


Figure 5-18 Seismic Line SAN-92-34 Showing Lead C and Location Map

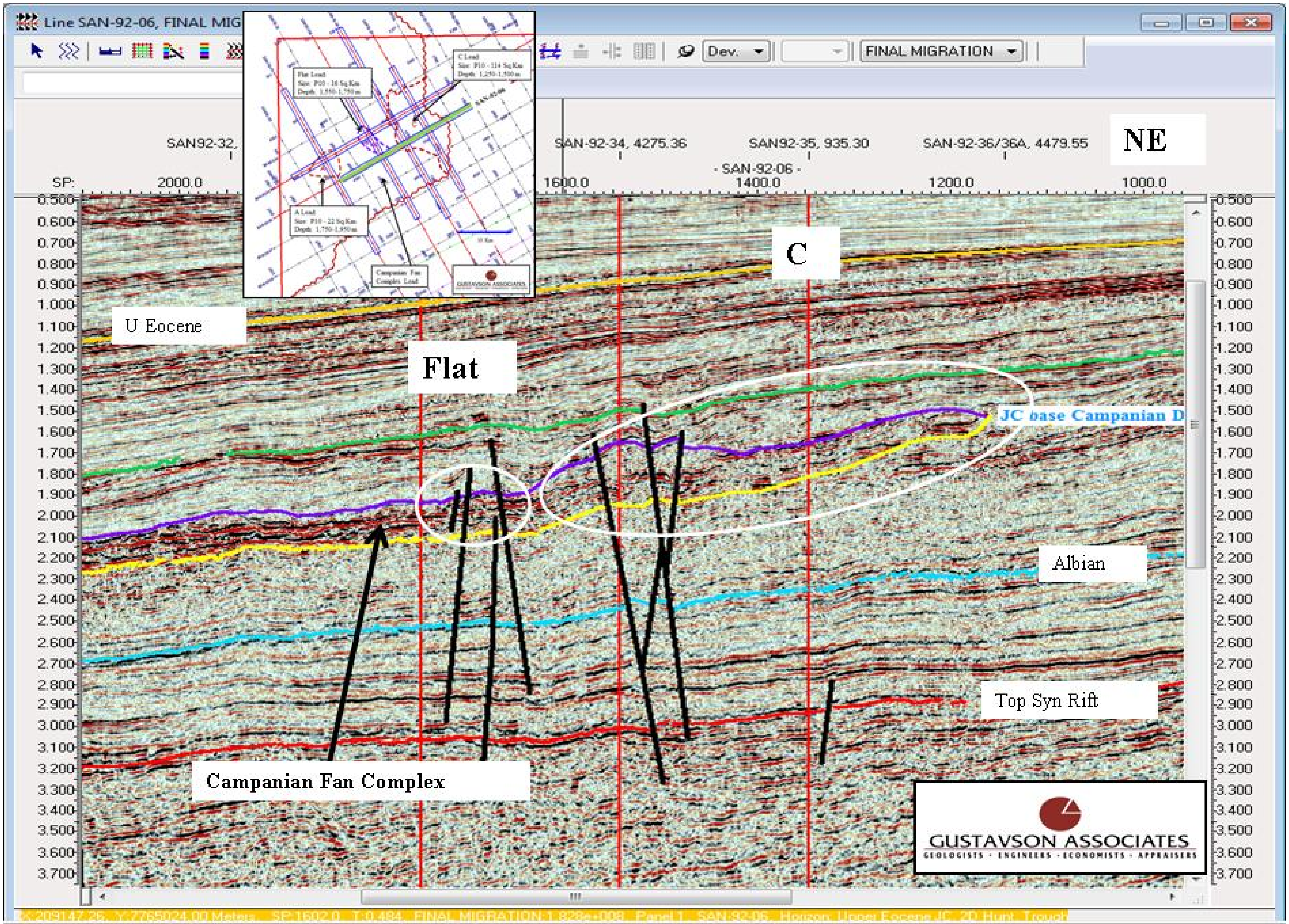


Figure 5-19 Seismic Line SAN-92-06 Showing Lead C and Flat and Location Map

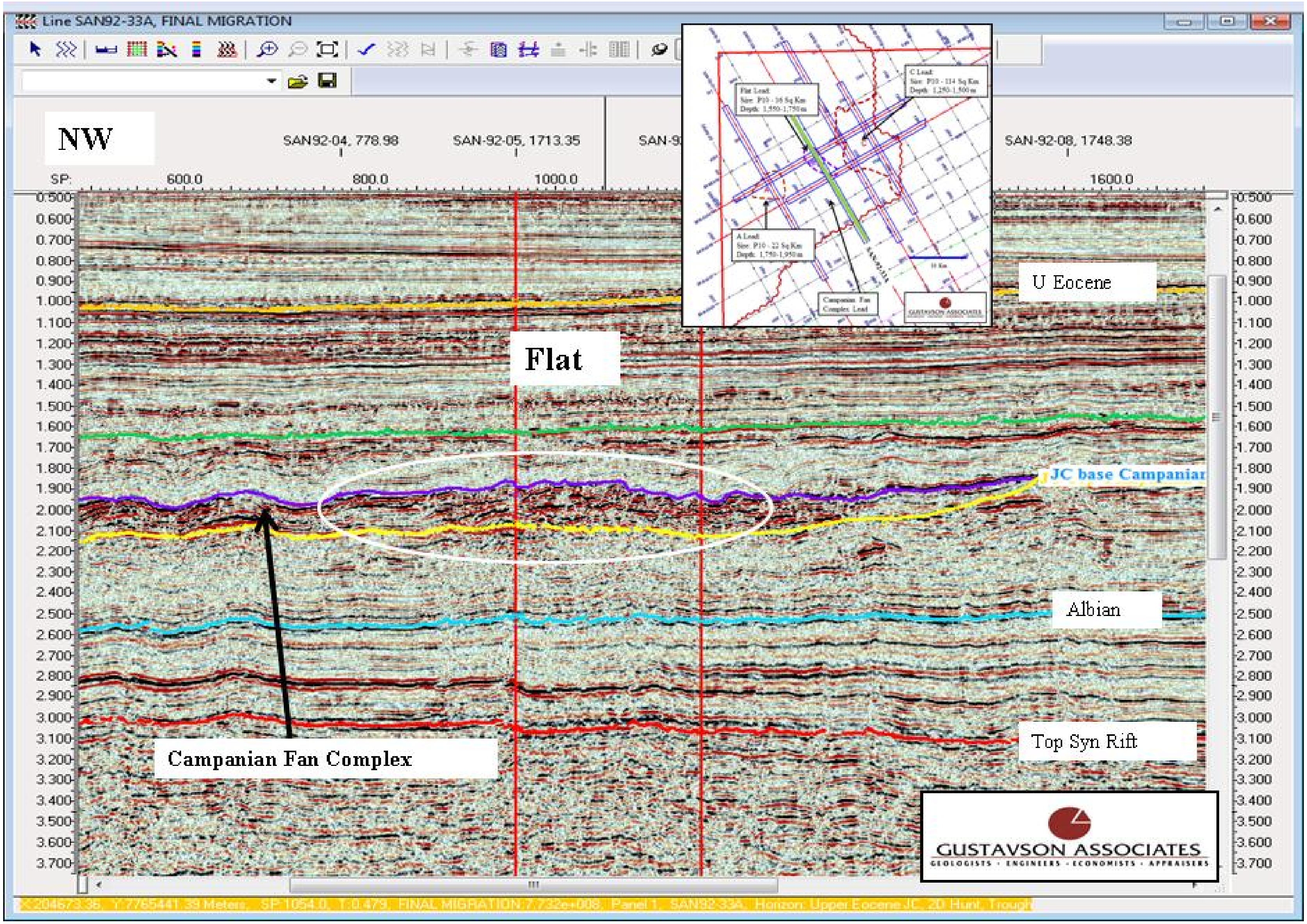


Figure 5-20 Seismic Line SAN-92-33A Showing Lead Flat and Location Map

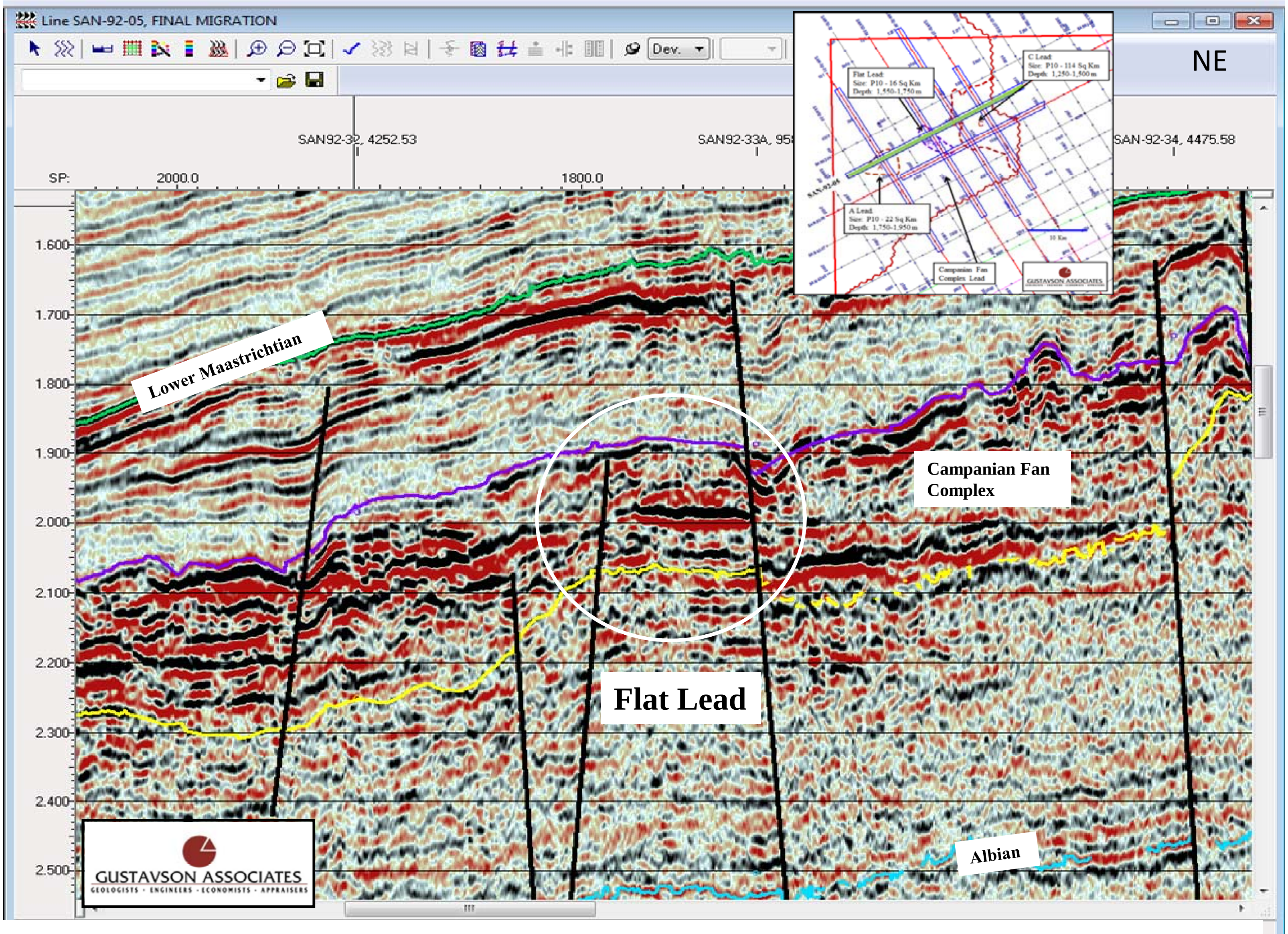


Figure 5-21 Seismic Line SAN-92-05 Showing Lead Flat and Location Map

5.12.2 <u>Maastrichtian Age Lead D</u>

Lead D is in Low Maastrichtian sediments. The map of this Lead is shown as Figure 5-22. Seismic lines that define this Lead are shown as Figure 5-23, Figure 5-24, Figure 5-25, and Figure 5-26.

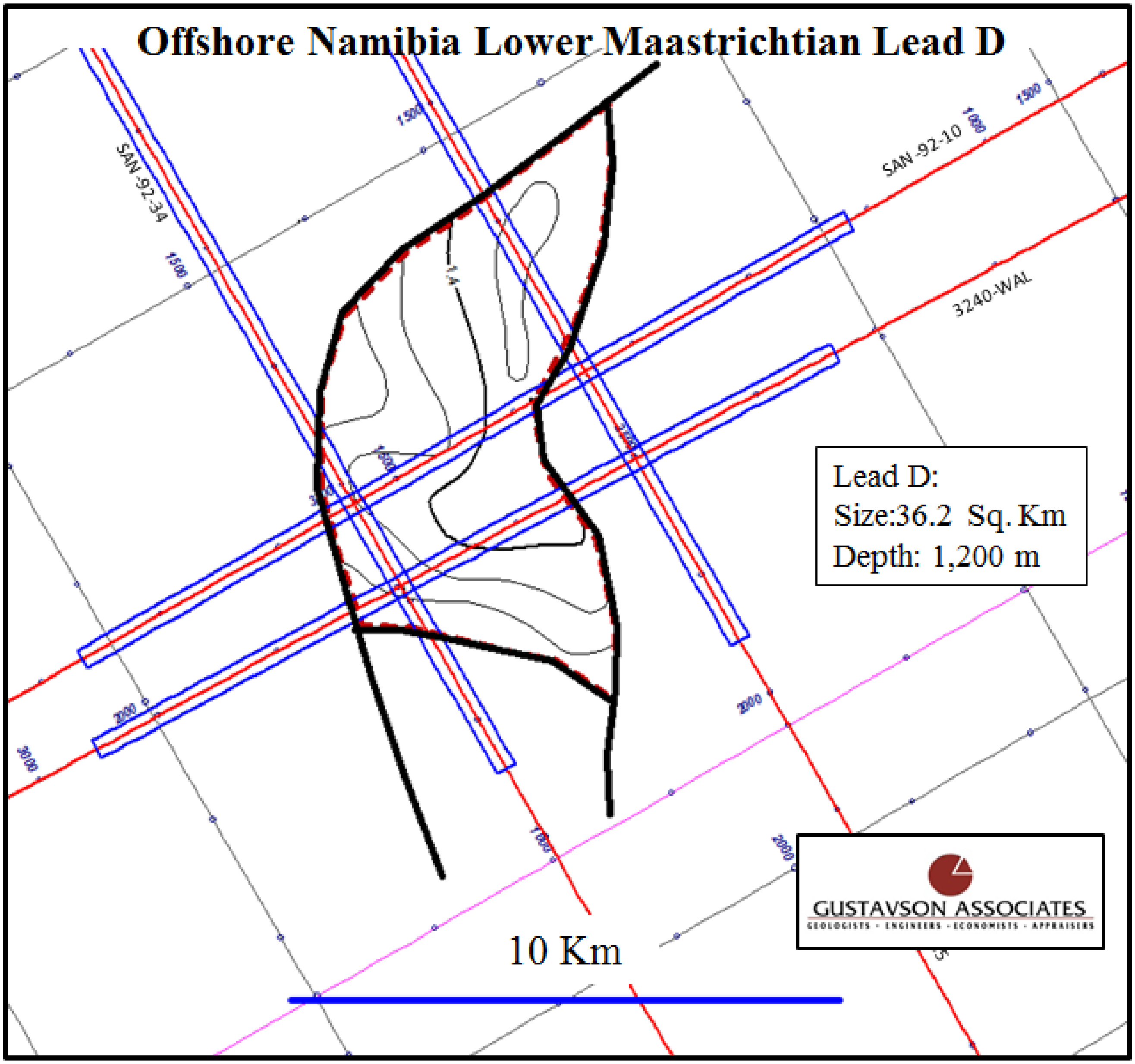


Figure 5-22 Lower Maastrichtian Lead D Map

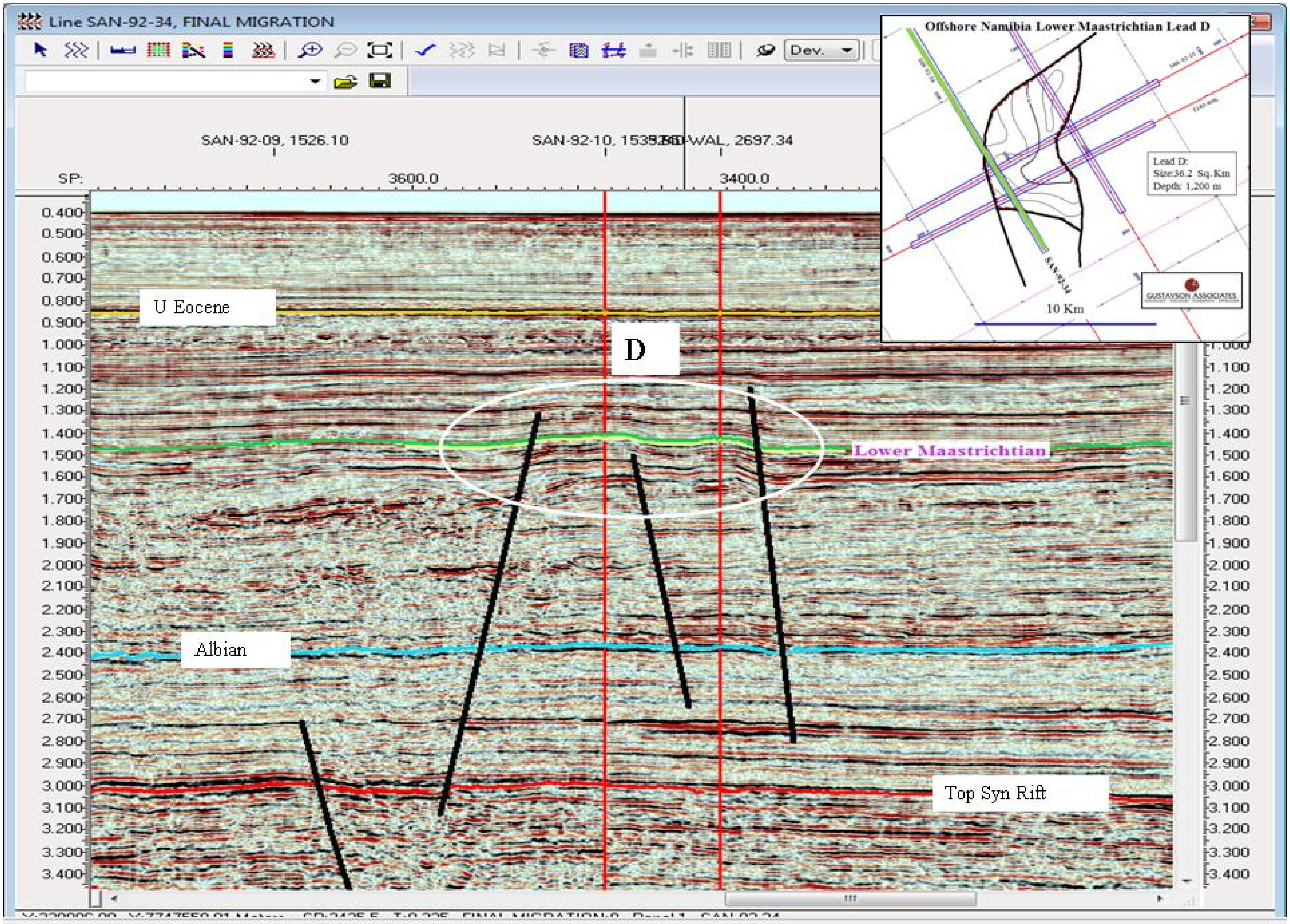


Figure 5-23 Seismic Line SAN-92-34 Showing Lead D and Location Map

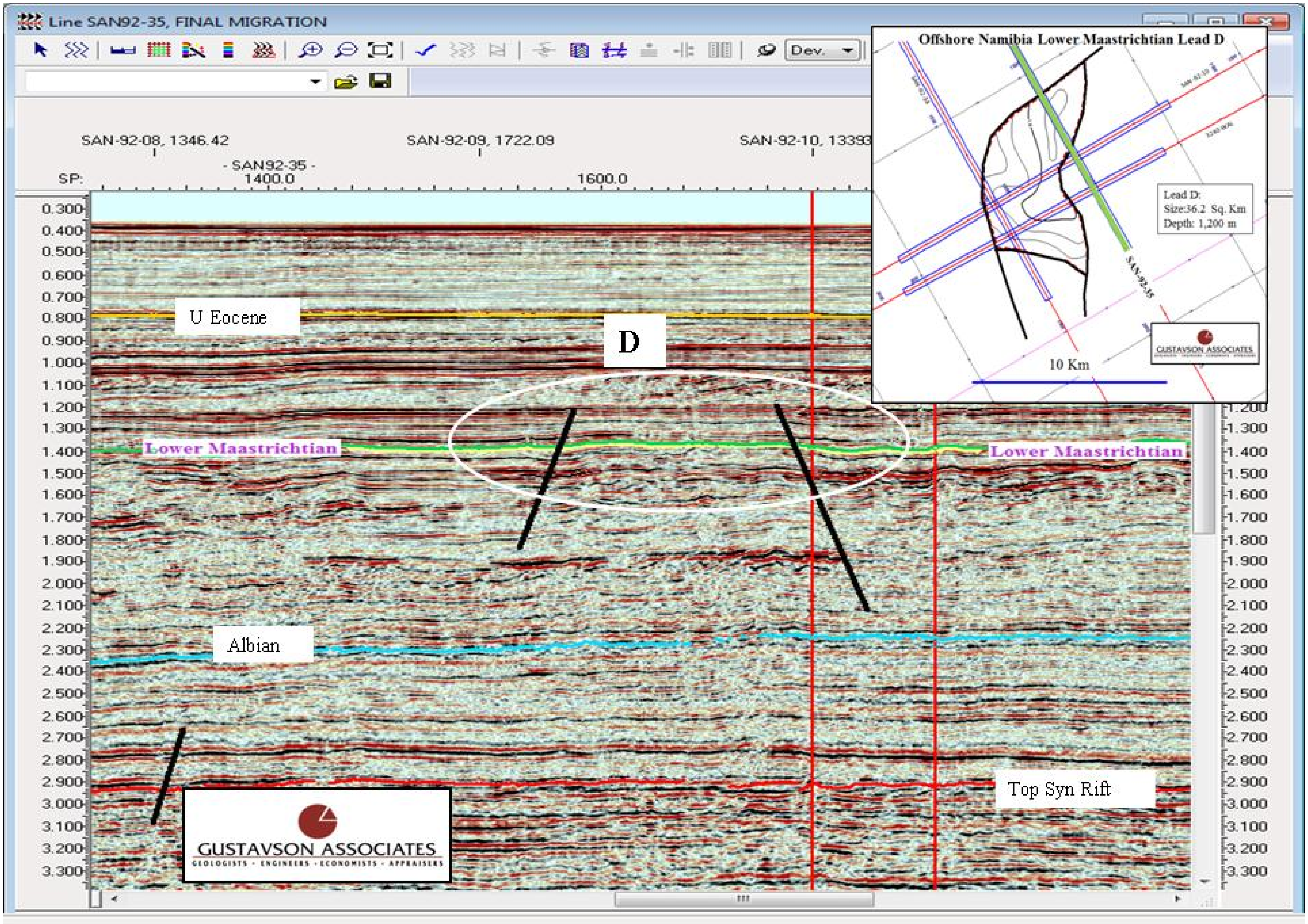


Figure 5-24 Seismic Line SAN-92-35 Showing Lead D and Location Map

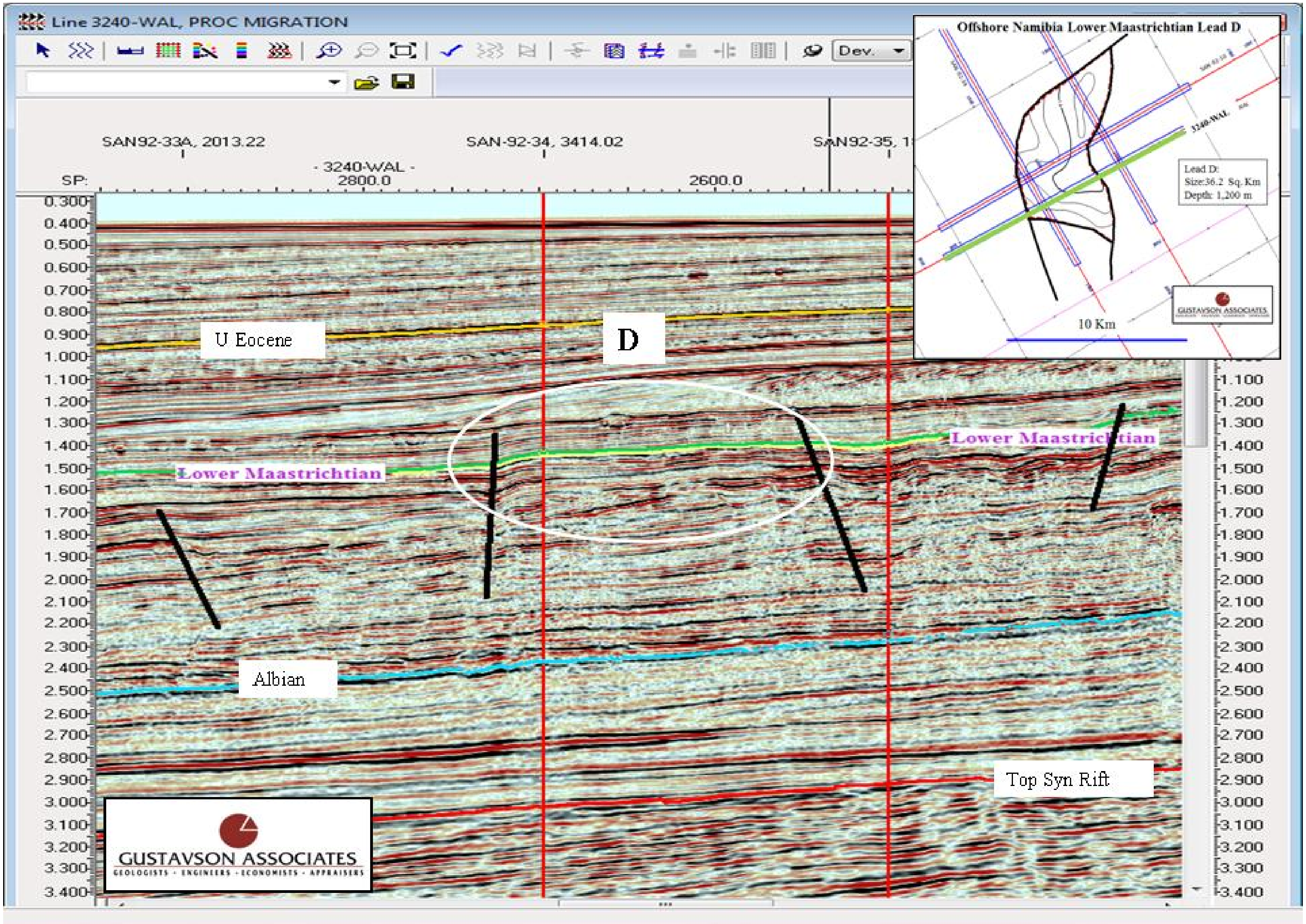


Figure 5-25 Seismic Line 3240-WAL Showing Lead D and Location Map

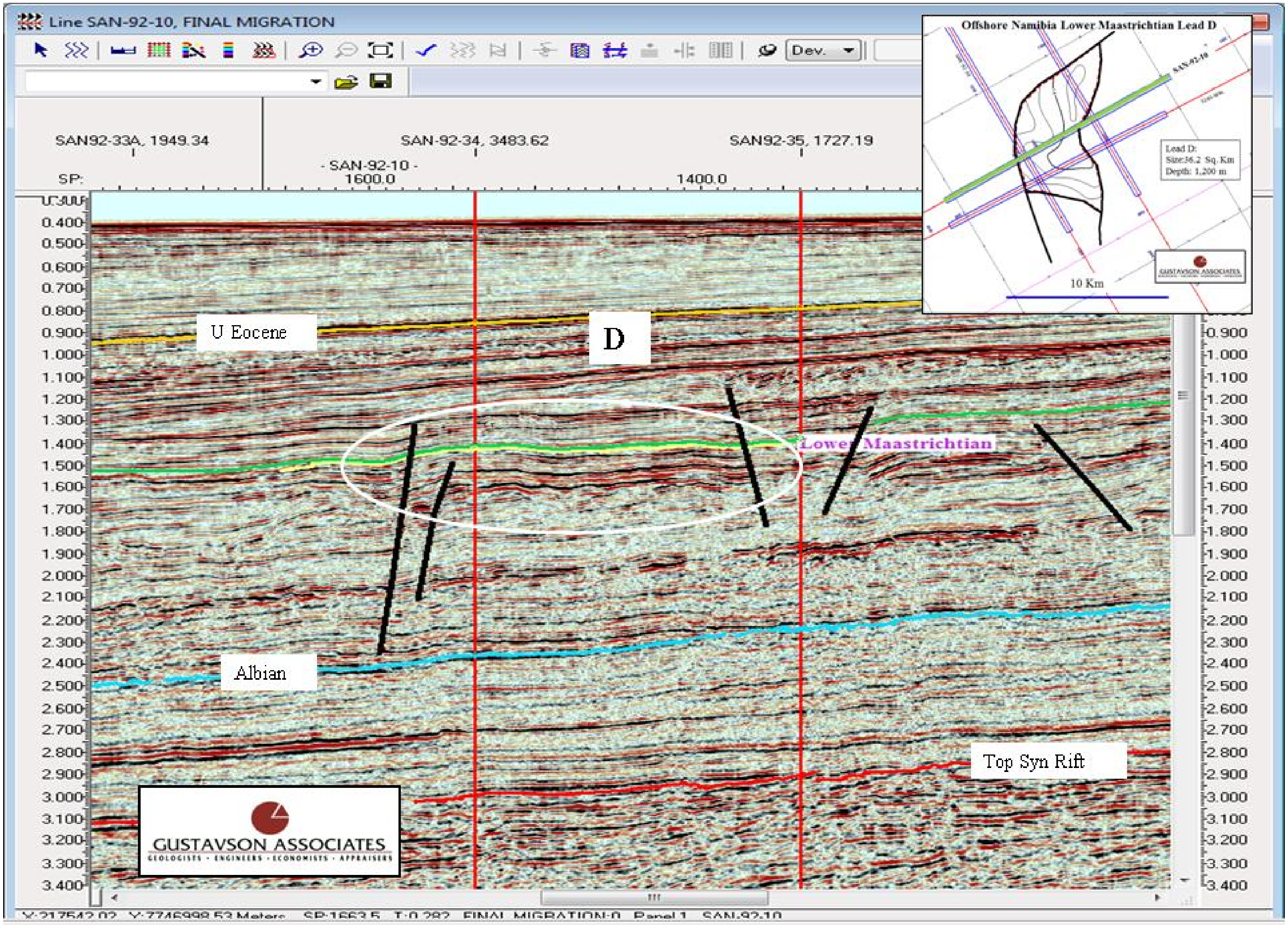


Figure 5-26 Seismic Line SAN-92-10 Showing Lead D and Location Map

5.12.3 Middle Albian Age Lead B

The map of the Lead B is shown on Figure 5-27. This lead is defined by the seismic lines shown as Figure 5-28, Figure 5-29, and Figure 5-30.

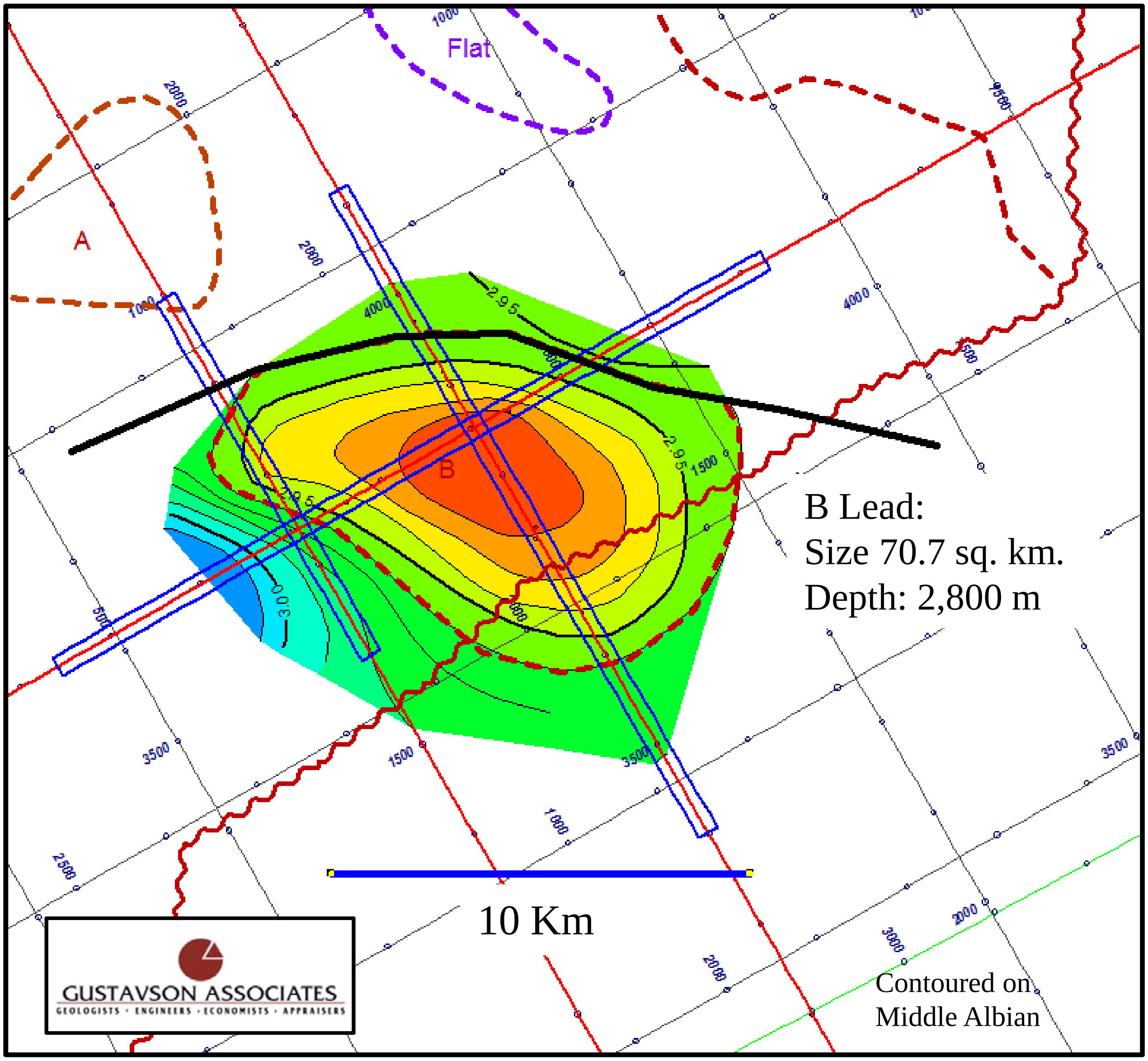


Figure 5-27 Seismic Map of Middle Albian Age Lead B

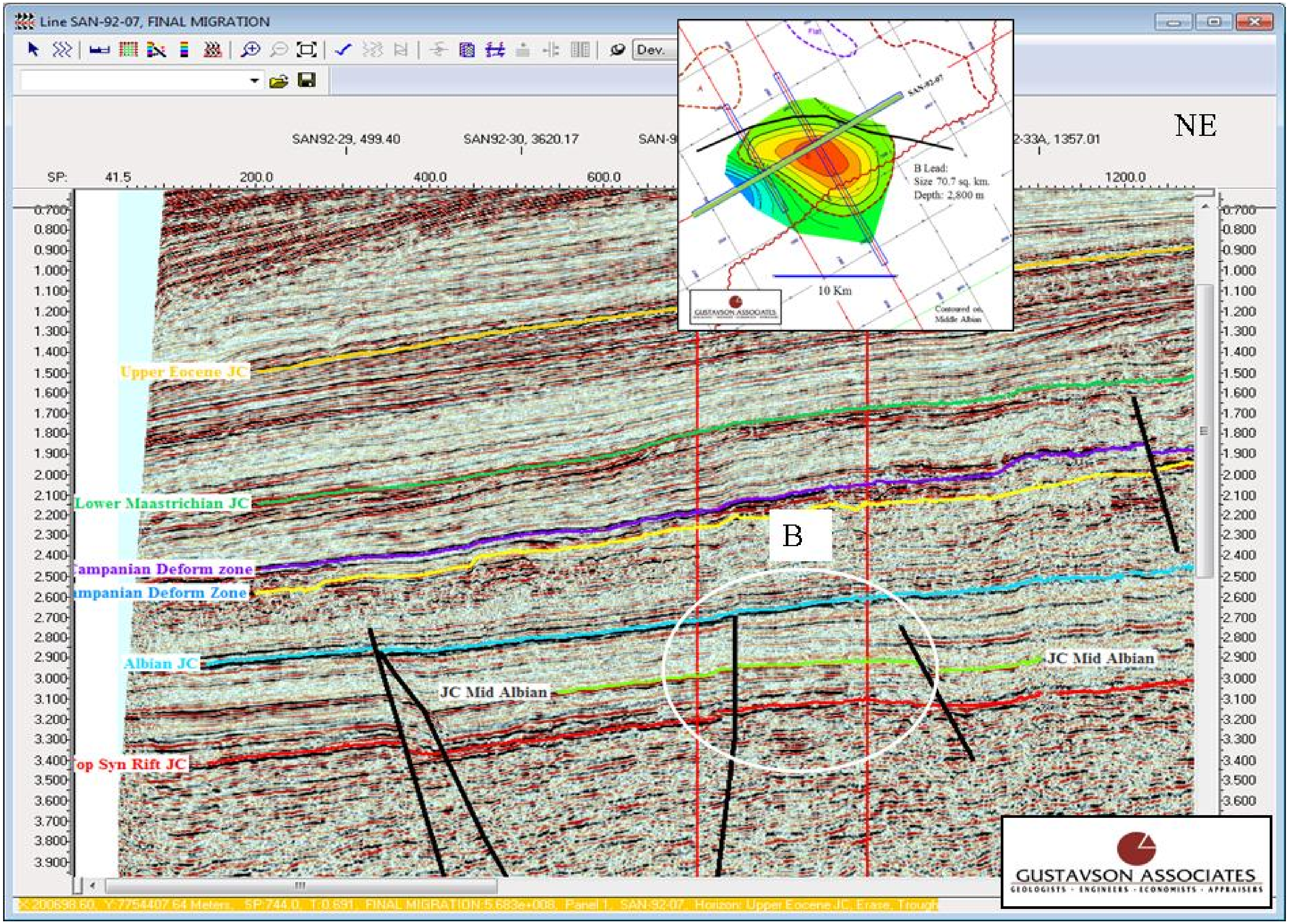
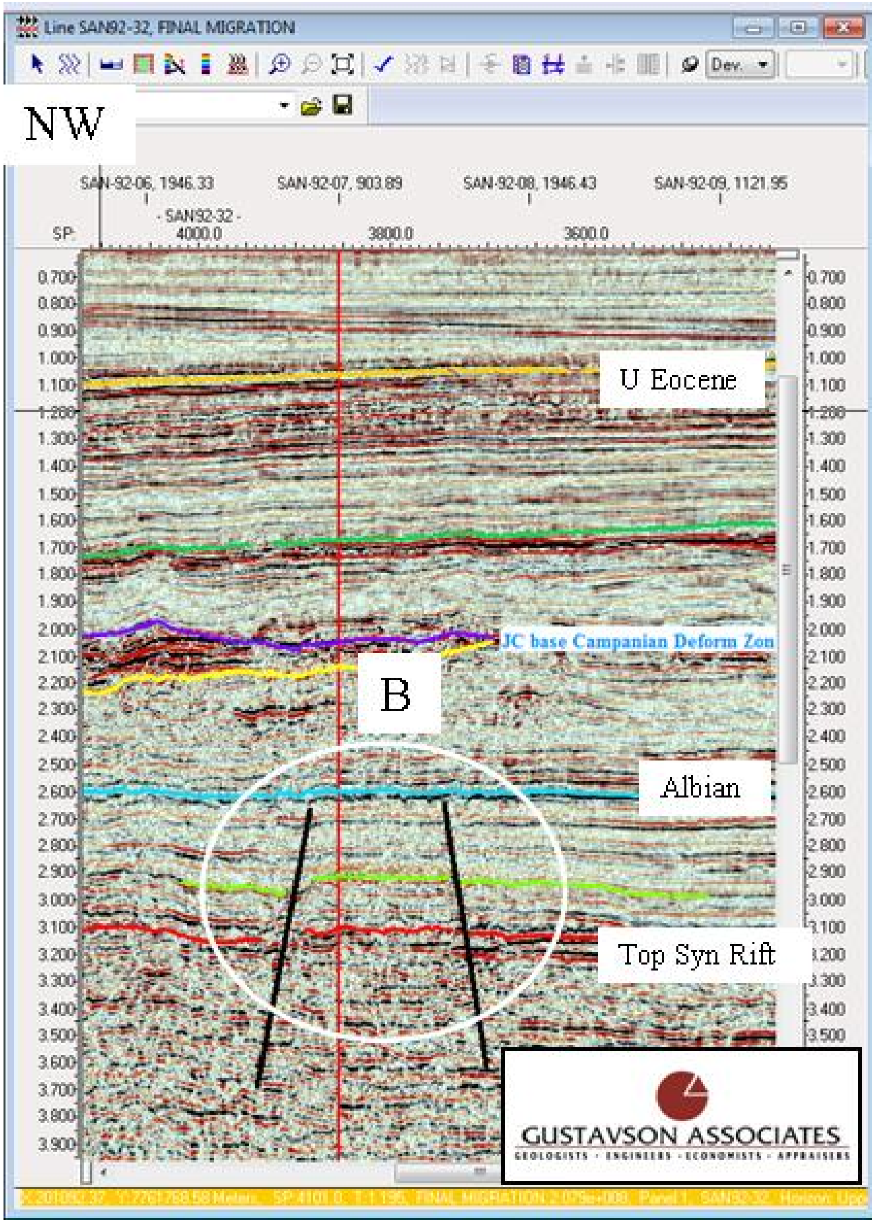


Figure 5-28 Seismic Line SAN-92-07 Showing Lead B and Location Map



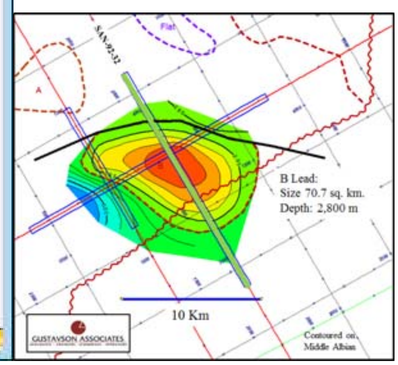


Figure 5-29 Northwest to Southeast Lines SAN-92-32 Showing Lead B and Location Map

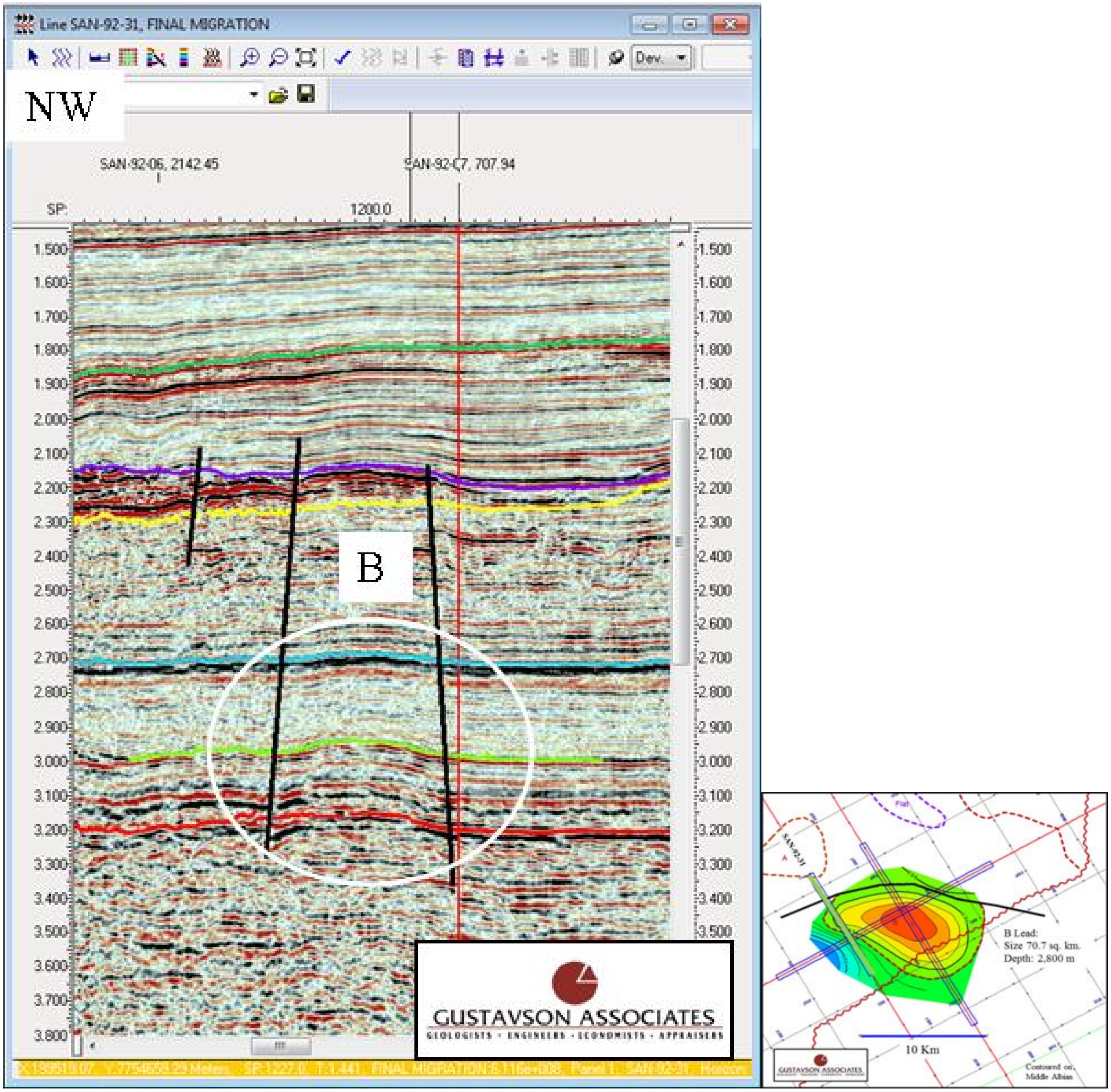


Figure 5-30 Northwest to Southeast Lines SAN-92-31 Showing Lead B and Location Map

5.12.4 Albian Channel Lead

The amplitude anomaly that defines the Albian Channel Lead is located on the seismic line map (Figure 5-31). The seismic map of the lead and the P10, P50, and P90 areas is shown as Figure 5-32. Seismic lines that define this lead are shown in Figure 5-33 and Figure 5-34.

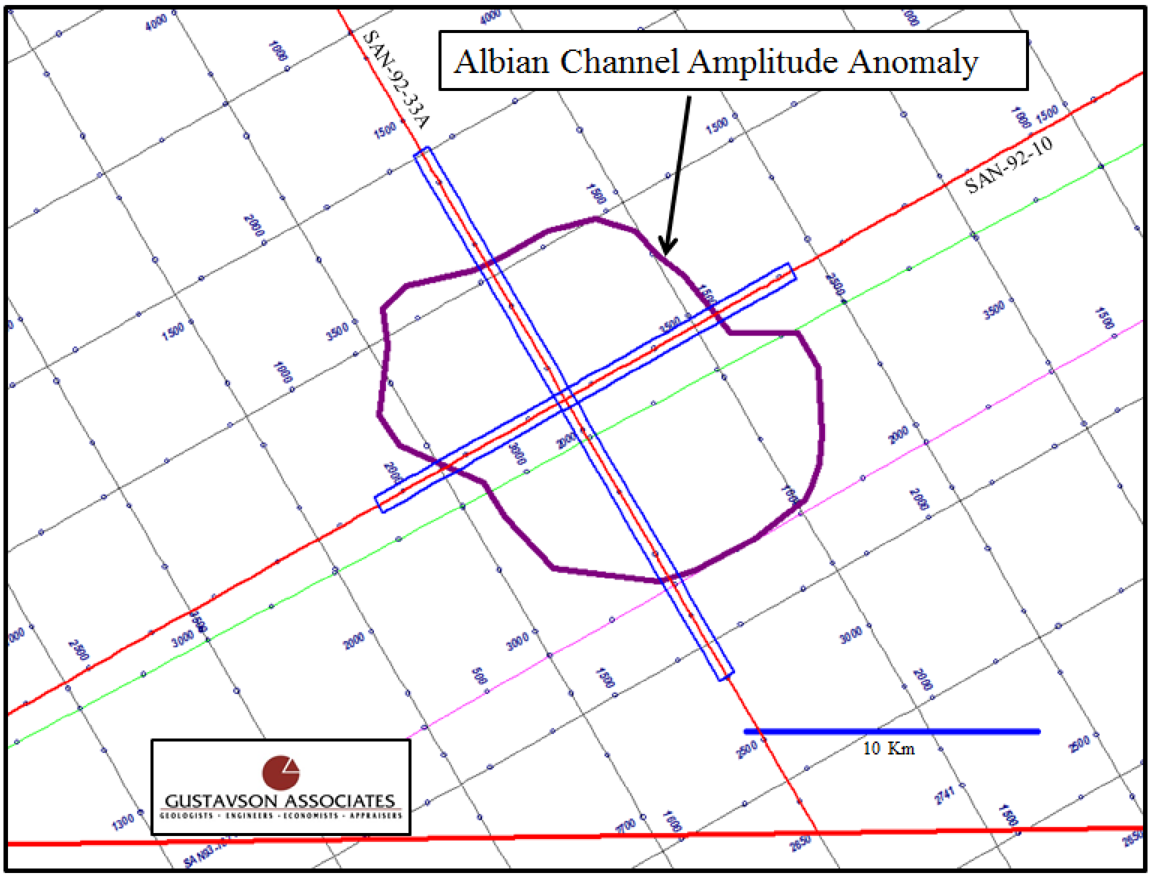


Figure 5-31 Albian Channel Lead Areal Extent Map

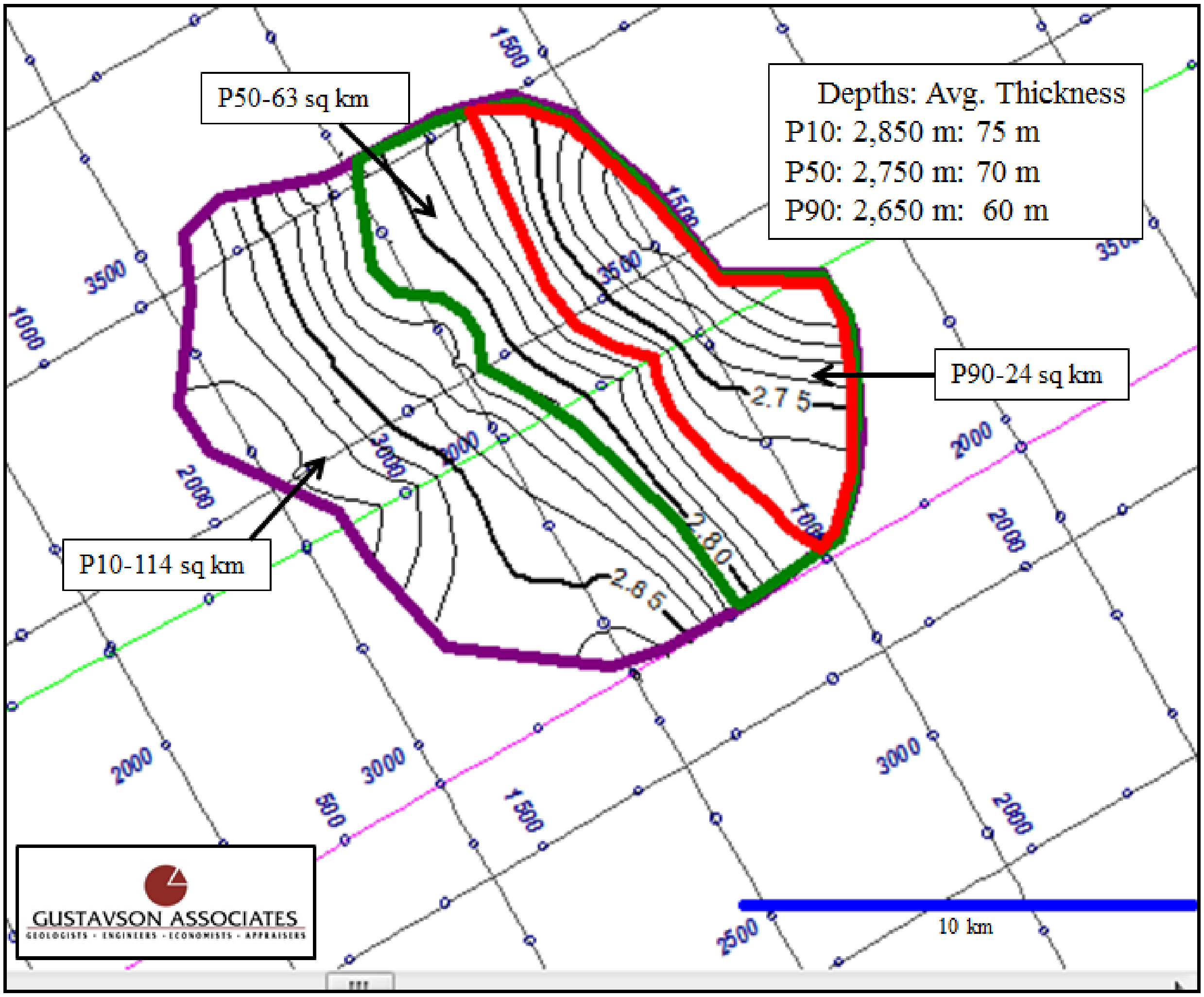


Figure 5-32 Seismic Time Map of Albian Channel Lead

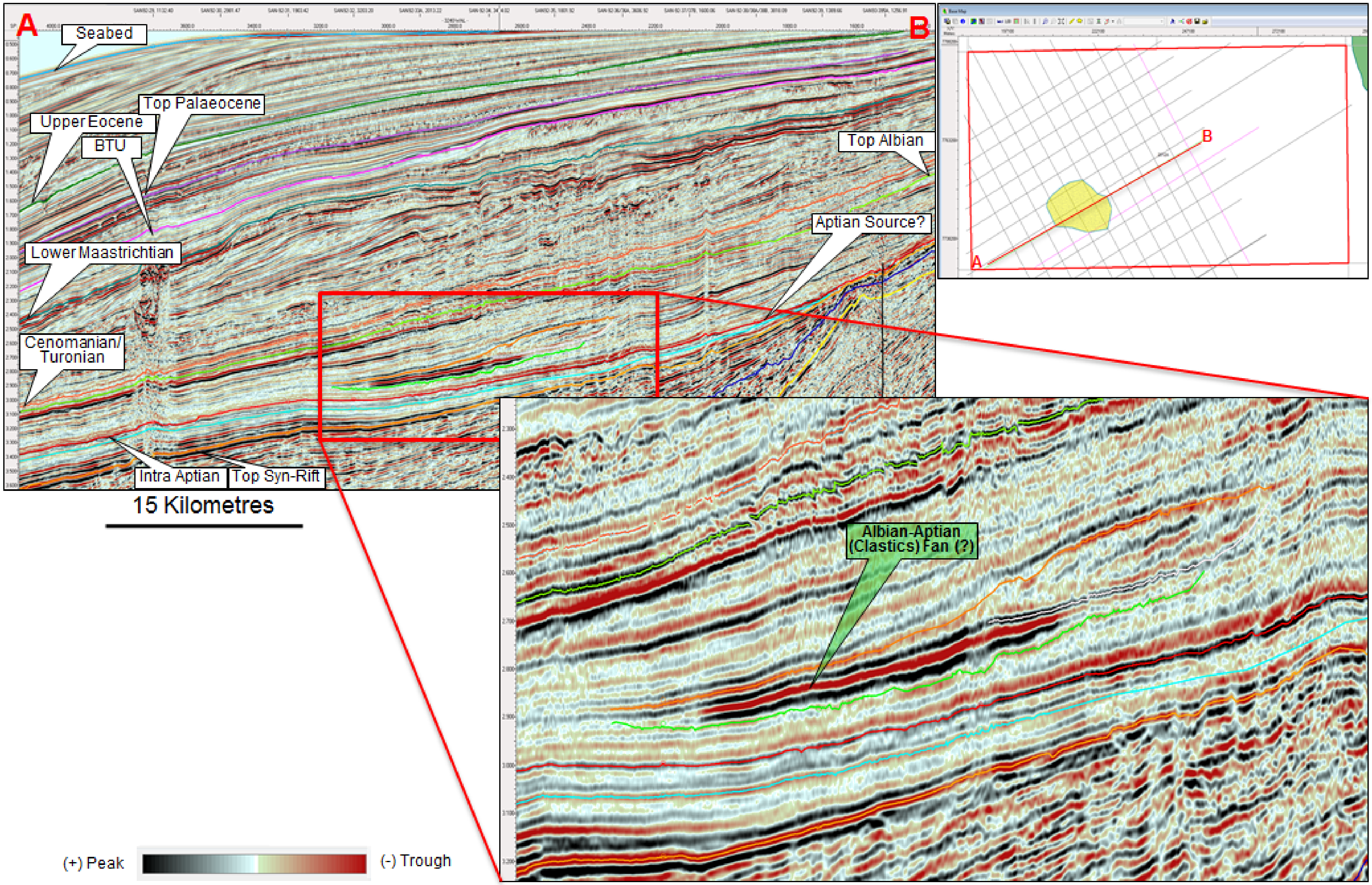


Figure 5-33 Line 3240-WAL Northwest to Southeast Showing the Albian Channel (after PGS)

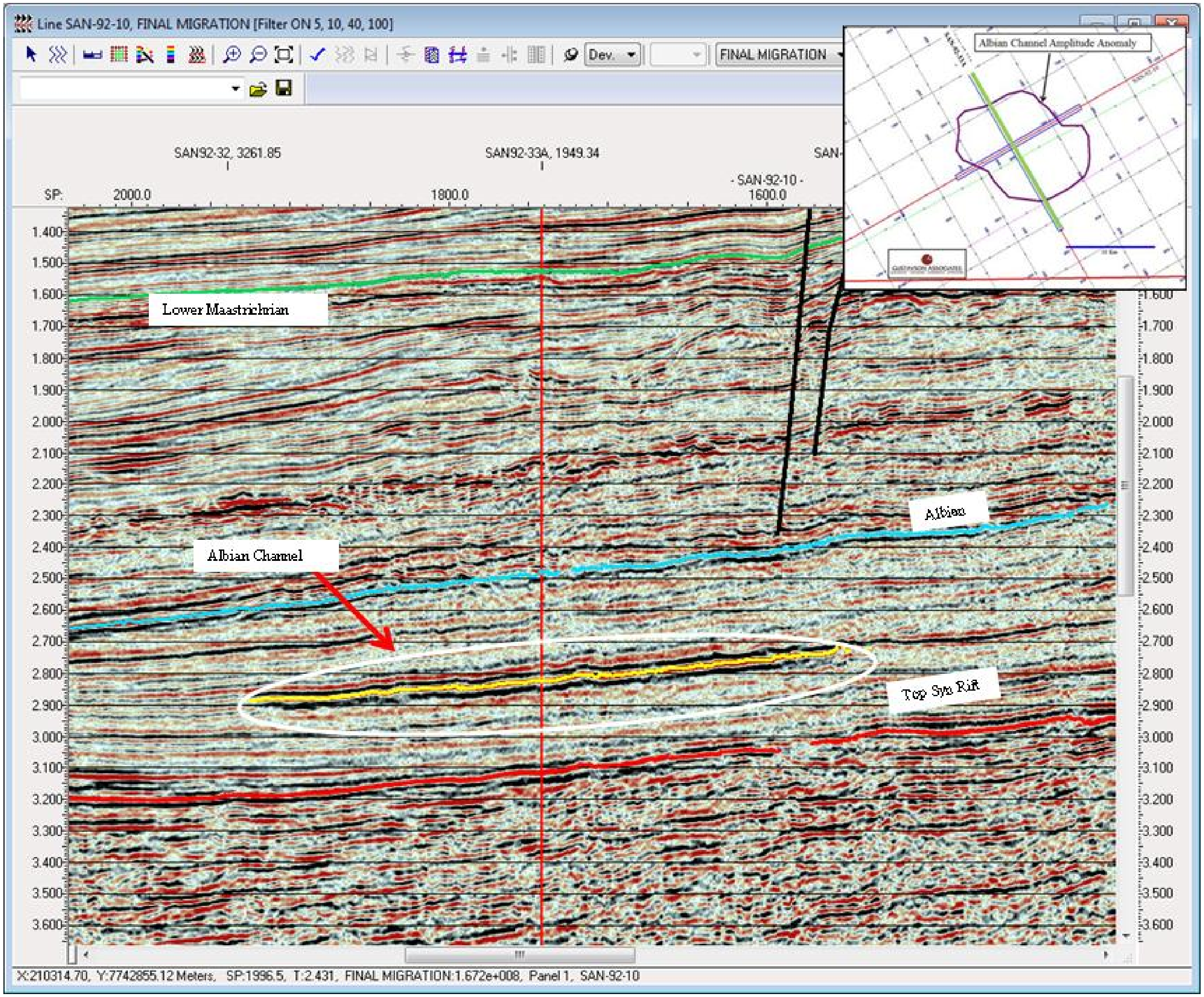


Figure 5-34 Line SAN-92-10 Southwest to Northeast Showing the Albian Channel and Location Map

5.13 LEAD SUMMARY

The leads are all in the western portion of Cooper Block (Figure 5-9). The 2D seismic data was tied into the Sasol 2012/13-1 well which is located on Block 2012B outside of the area of interest. All leads presented here except for the Campanian Fan and Albian Channel leads are interpreted to be formed by extensional forces causing structural closure within the Cretaceous section. The interpretation utilized excellent Miocene, Upper Cretaceous and Albian/Aptian reflectors which can be tied back to the 2012/13-001.

Leads A, B, C, D, and Flat are structural in nature. They are fault bounded and have structural closure in all cases of over 75 meters starting from the Maastrichtian and persisting through the Cenomanian and Albian in most cases. The bounding faults extend to the Lower Cretaceous and would provide a convenient path for hydrocarbon migration from the Turonian-Cenomanian and deeper source rocks.

Leads A, Flat, and C are prospective in and have structural closure in the Upper Cretaceous Campanian fan system and consist of a series of multiple high amplitude seismic events. The high amplitude “flat” event is interpreted to possibly be a gas-water, oil water or oil-gas interface within the aptly named Flat Lead in the Campanian level.

Lead B is a fault bounded anticline seen in the mid-Albian section. The faults appear to extend into the syn-rift section.

Lead D is interpreted to be a fault bounded Lower Maastrichtian structural closure. Some of the faults appear to extend down to the Syn-Rift section. This feature appears to be completely fault bounded.

The Campanian Fan Lead is interpreted to be a stratigraphic accumulation of sands and shales dipping to the west southwest which could contain hydrocarbons on multiple levels.

The Albian Channel Lead is a “bright” event on the seismic that appears on several seismic lines. This feature is interpreted to be a sand filled channel with stratigraphic terminations along with a structural component.

5.14 DATABASE

There is a paucity of well data in the offshore of Namibia and the bulk of the seismic data consists of speculative 2D data acquired by TGS-NOPEC, Western-GECO, and CGGVeritas.

5.14.1 Seismic Data

ECO has purchased the rights to 831.7 line kilometers of 2D seismic data from TGS-NOPEC over Cooper Block. The data acquired by ECO is adequate to identify several large lead areas on the block. ECO has also obtained access to additional seismic data from PGS which has a total of 1,450 line kilometers of 2D seismic.

5.14.2 Well Data

A total of six wells have been drilled in the vicinity of Cooper Block. These wells include the 1911/10-1 well drilled by Norsk Hydro Namibia in early 1995 to a depth of 4,185 meters in a water depth of 631 meters; the 1911/15-1 well drilled by Norsk Hydro Namibia in early 1994 to a depth of 4,586 meters in a water depth of 521.5 meters. The seismic data is tied to the Sasol 2012/13-1 well located to the south of Cooper Block. This well was drilled in early 1997 to a depth of 3,714 meters in a water depth of 688 meters. The Ranger Oil Namibia Ltd 2213/6-1 was drilled in early 1995 to a depth of 2,627 meters in a water depth of 218 meters. All of the available reports offered by Namcor, the Namibian oil company, were copied for ECO. These reports are largely biostratigraphic studies and core reports of cores taken in the deeper Campanian and Albian sections. Electric well log data from six wells in the area were provided by ECO. However, the petrophysical characteristics used for the Cretaceous section were assumed to be similar to sand and shale accumulations in other parts of the world.

Based on information released by HRT, the Wingat-1 well was drilled in block 2212A to a depth of 5,000 meters and found two well-developed source rocks in the oil window. Several thin bedded oil saturated sands found with 41 degree API oil with a 1,193 GOR. The Murombe-1 well, also located in block 2212A, was drilled to a depth of 5,729 meters TD. This well found a 242 meter interval containing 36 meters net sand (assumed to be Upper Cretaceous age) with an average porosity of 19% and wet. This well also found the same well developed marine source rock as the Wingat. The Moosehead-1 well was drilled in block 2713 northwest of KUDU field to 4,170 meters with wet gas shows and found two potential source rocks including the Aptian.

6. PROBABILISTIC RESOURCE ANALYSIS

6.1 GENERAL

A probabilistic resource analysis is most applicable for projects such as evaluating the potential resources of an exploratory area like the Cooper Block, where a range of values exists in the reservoir parameters. The range of the expected reservoir data is quantified by probability distributions, and an iterative approach yields an expected probability distribution for potential resources. This approach allows consideration of most likely resources for planning purposes, while gaining an understanding of what volumes of resources may have higher certainty, and what potential upside may exist for the project.

The analysis for this project was carried out considering the range of values for all parameters in the volumetric resource equations.

6.2 INPUT PARAMETERS

This method involves estimating probability distributions for the range of reservoir parameters and performing a statistical risk analysis involving multiple iterations of resource calculations generated by random numbers and the specified distributions of reservoir parameters. To do this, each parameter incorporated in our resource calculation was evaluated for its expected probability distribution.

Because few data are available about the likely distribution of the reservoir parameters, simple triangular distributions with specification of minimum, most likely or mode, and maximum values were used for most of the parameters. The exception to this is the reservoir area, for which triangular distributions with specification of minimum, most likely or mode, and P_{10} values were used.[7] Note that these parameters represent average parameters over the entire prospect. So, for example, the porosity ranges do not represent the range of what porosity might

[7] The original intention was that the low values specified would represent P_{90} values rather than minima; however, this assumption resulted in some negative values.

be in a particular well or a particular interval, but rather the reasonable range of the average porosity for the whole prospect. The reservoir areas for the A, C and Flat Leads were subtracted from the total area for the Campanian Fan and the appropriate Gross Thickness and Net to Gross parameters were applied accordingly. A summary of input parameters is shown in Table 6-1.

In a probabilistic analysis, dependent relationships can be established between parameters if appropriate. For example, portions of a reservoir with the lowest effective porosity generally may be expected to have the highest connate water saturation, whereas higher porosity sections have lower water saturation. In such a case, it is appropriate to establish an inverse relationship between porosity and water saturation, such that if a high porosity is randomly estimated in a given iteration, corresponding low water saturation is estimated. The degree of such a correlation can be controlled to be very strong or weak. This type of dependency, with a medium strength of -0.7, was used in this study for porosity with water saturation and with net/gross ratio. Similarly, the low end of the gross thickness distributions for this prospective accumulation would generally be expected to occur when the productive area is small; therefore, a positive correlation of 0.7 was assigned to gross thickness and productive area.

Table 6-1 Input Parameters for All Leads[8]

	Lead A (Campanian)			Lead B (Mid Albian)			Lead C (Campanian)		
	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
Oil Gravity	30.00	35.00	40.00	30.00	35.00	40.00	30.00	35.00	40.00
Gas-Oil Ratio	500.00	1,000.00	1,500.00	500.00	1,000.00	1,500.00	500.00	1,000.00	1,500.00
Gas Gravity	0.65	0.70	0.75	0.65	0.70	0.75	0.65	0.70	0.75
press gradient	0.44	0.45	0.48	0.44	0.45	0.48	0.44	0.45	0.48
Depth	5,741	6,069	6,397	8,986	9,186	9,386	4,101	4,511	4,921
Porosity	10.00	21.00	30.00	10.00	21.00	30.00	10.00	21.00	30.00
Water Sat.	20.00	30.00	40.00	20.00	30.00	40.00	20.00	30.00	40.00
Drainage area	1,087	2,718	5,436	3,494	8,735	17,470	5,634	14,085	28,170
Gross Thickness	492	640	787	590	689	787	164	541	918
Net/Gross	0.25	0.55	0.75	0.25	0.55	0.75	0.25	0.55	0.75
% Recovery	0.15	0.20	0.35	0.15	0.20	0.35	0.15	0.20	0.35

	Lead D (Maastrichtian)			Lead 'Flat' (Campanian)				Campanian 'Fan'	
	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum	Minimum	Most Likely	Maximum
Oil Gravity	30.00	35.00	40.00	30.00	35.00	40.00	30.00	35.00	40.00
Gas-Oil Ratio	500.00	1,000.00	1,500.00	500.00	1,000.00	1,500.00	500.00	1,000.00	1,500.00
Gas Gravity	0.65	0.70	0.75	0.65	0.70	0.75	0.65	0.70	0.75
press gradient	0.44	0.45	0.48	0.44	0.45	0.48	0.44	0.45	0.48
Depth	3,737	3,937	4,137	5,085	5,413	5,741	5,085	5,577	7,218
Porosity	10.00	21.00	30.00	10.00	21.00	30.00	10.00	21.00	30.00
Water Sat.	20.00	30.00	40.00	20.00	30.00	40.00	20.00	30.00	40.00
Drainage area	1,789	4,473	8,945	791	1,977	3,954	83,522	168,774	274,783
Gross Thickne	225	450	900	590	689	787	328	460	574
Net/Gross	0.25	0.55	0.75	0.25	0.55	0.75	0.10	0.25	0.50
% Recovery	0.15	0.20	0.35	0.15	0.20	0.35	0.15	0.20	0.35

	Albian Channel		
	Minimum	Most Likely	Maximum
Oil Gravity	30.00	35.00	40.00
Gas-Oil Ratio	500.00	1,000.00	1,500.00
Gas Gravity	0.65	0.70	0.75
press gradient	0.44	0.45	0.48
Depth	8,694	9,022	9,350
Porosity	10.00	21.00	30.00
Water Sat.	20.00	30.00	40.00
Drainage area	5,930	15,568	28,170
Gross Thickne	197	230	246
Net/Gross	0.25	0.55	0.75
% Recovery	0.15	0.20	0.35

6.3 PROBABILISTIC SIMULATION

Probabilistic resource analysis was performed using the Monte Carlo simulation software called "@ Risk". This software allows for input of a variety of probability distributions for any

[8] Area in Acres, Depth and Thickness in feet.

parameter. Then the program performs a large number of iterations, either a large number specified by the user, or until a specified level of stability is achieved in the output. The results include a probability distribution for the output, sampled probability for the inputs, and sensitivity analysis showing which input parameters have the most effect on the uncertainty in each output parameter.

After distributions and relationships between input parameters were defined, a series of simulations were run wherein points from the distributions were randomly selected and used to calculate a single iteration of estimated potential resources. The iterations were repeated until stable statistics (mean and standard deviation) result from the resulting output distribution. This occurred after 5,000 iterations.

6.4 RESULTS

The output distributions were then used to characterize the Prospective Resources. Graphs of cumulative probability versus prospective resources were constructed. Results are summarized in Table 6-2. Note that these estimates do not include consideration for the risk of failure in exploring for these resources.

Table 6-2 Gross Prospective Unrisked Resource Estimates by Lead

	Oil in Place, MMBO			**Prospective Oil Resources, MMBO**		
Lead	Low Estimate	Best Estimate	High Estimate	Low Estimate	Best Estimate	High Estimate
A (Campanian)	413.0	784.0	1,369.6	90.8	179.9	327.9
B (Albian)	1,317.3	2,478.5	4,271.3	290.2	569.4	1,029.8
C (Campanian)	1,658.8	3,528.0	6,797.4	368.7	812.2	1,662.2
D (Maastrichtian)	544.2	1,128.3	2,160.0	120.4	256.6	516.4
Flat (Campanian)	339.3	628.4	1,104.8	73.0	143.8	265.0
Campanian Fan	4,939.1	9,512.1	17,596.3	1,083.5	2,177.0	4,208.2
Albian Channel	942.6	1,744.2	2,979.9	208.4	394.4	711.4
Total	10,154.3	19,803.5	36,279.4	2,235.1	4,533.3	8,720.9

Prospective Resources are defined as “those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity."[9] There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. The Low Estimate represents the P_{90} values from the probabilistic analysis (in other words, the value is greater than or equal to the P_{90} value 90% of the time), while the Best Estimate represents the P_{50} and the High Estimate represents the P_{10}.[10]

The distribution graphs for the resource estimates can be found in Figure 6-1 through Figure 6-5. It should be noted that the shape of the probability distributions all result in wide spacing between the minimum and maximum expected resources. This is reflective of the high degree of uncertainty associated with any evaluation such as this one prior to actual field discovery, development, and production. Also note that, in general, the high probability resource estimates at the left side of these distributions represents downside risk, while the low probability estimates on the right side of the distributions represent upside potential. These distributions do not include consideration of the probability of success of discovering commercial quantities of oil, but rather represent the likely distribution of oil discoveries, if successfully found.

[9] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook, Second Edition*, Volume 1, September 1, 2007, pg 5-7.
[10] Society of Petroleum Evaluation Engineers, (Calgary Chapter): *Canadian Oil and Gas Evaluation Handbook, Second Edition,* Volume 1, September 1, 2007, pg 5-7.

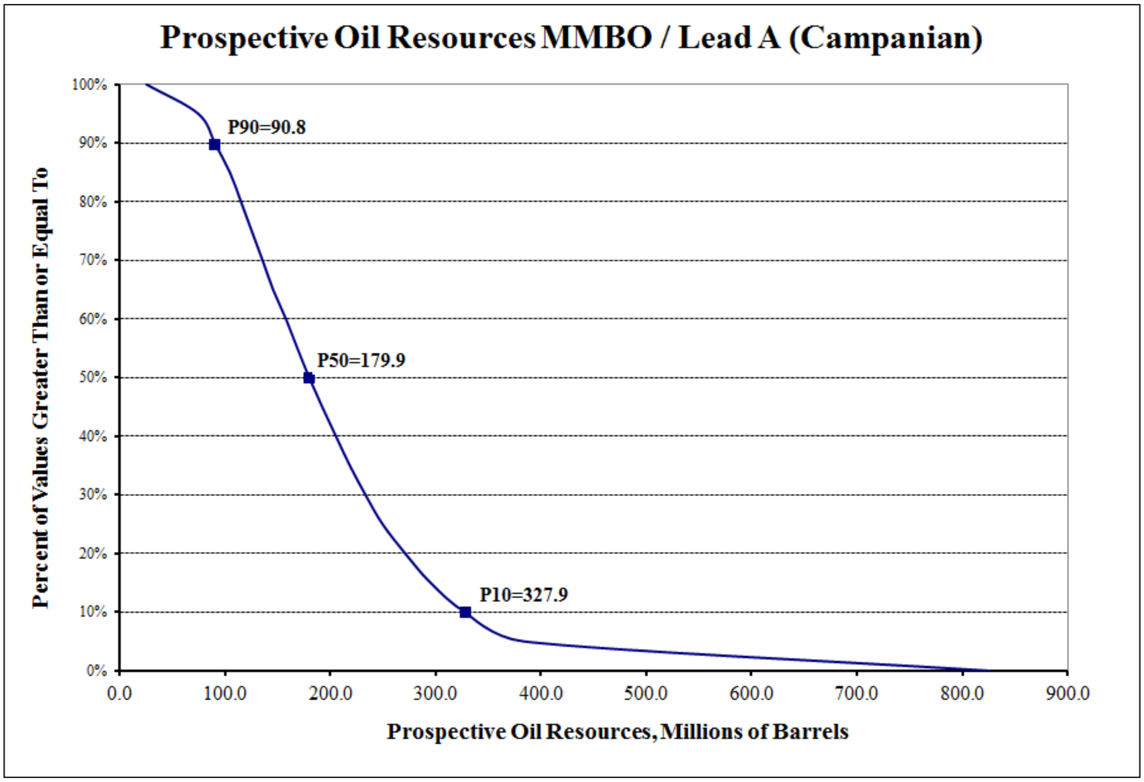


Figure 6-1 Distribution of Prospective Oil Resources, Lead A

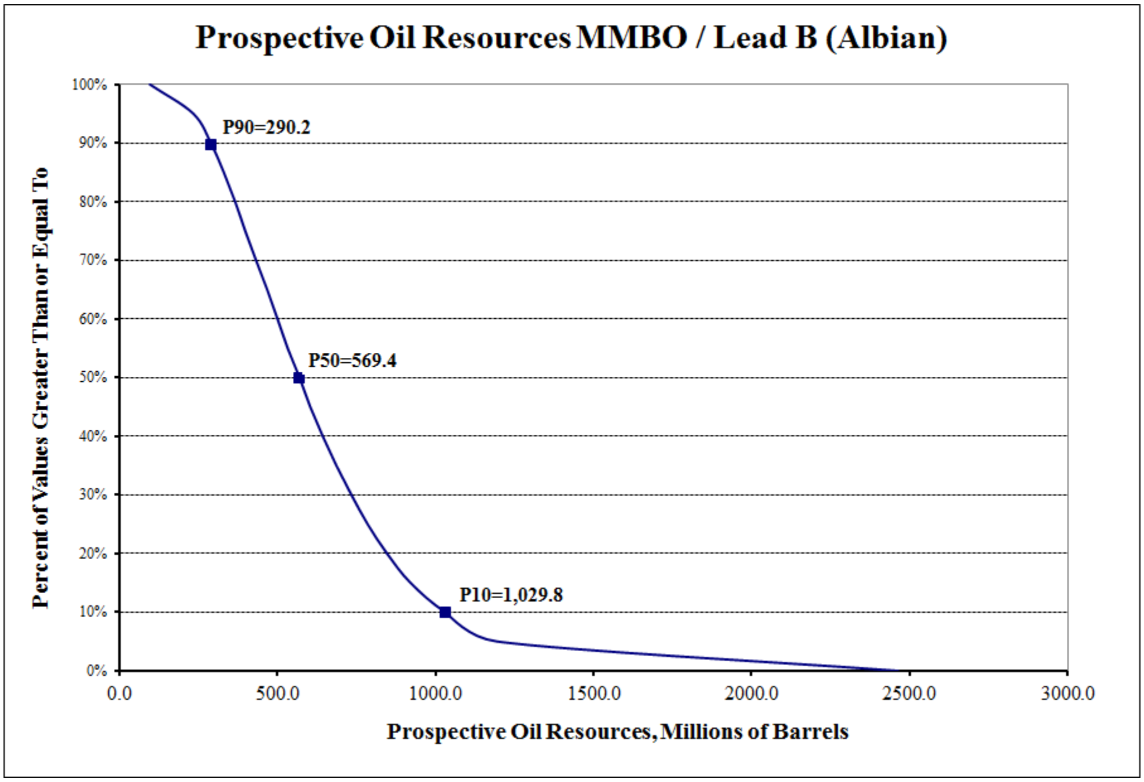


Figure 6-2 Distribution of Prospective Oil Resources, B Lead

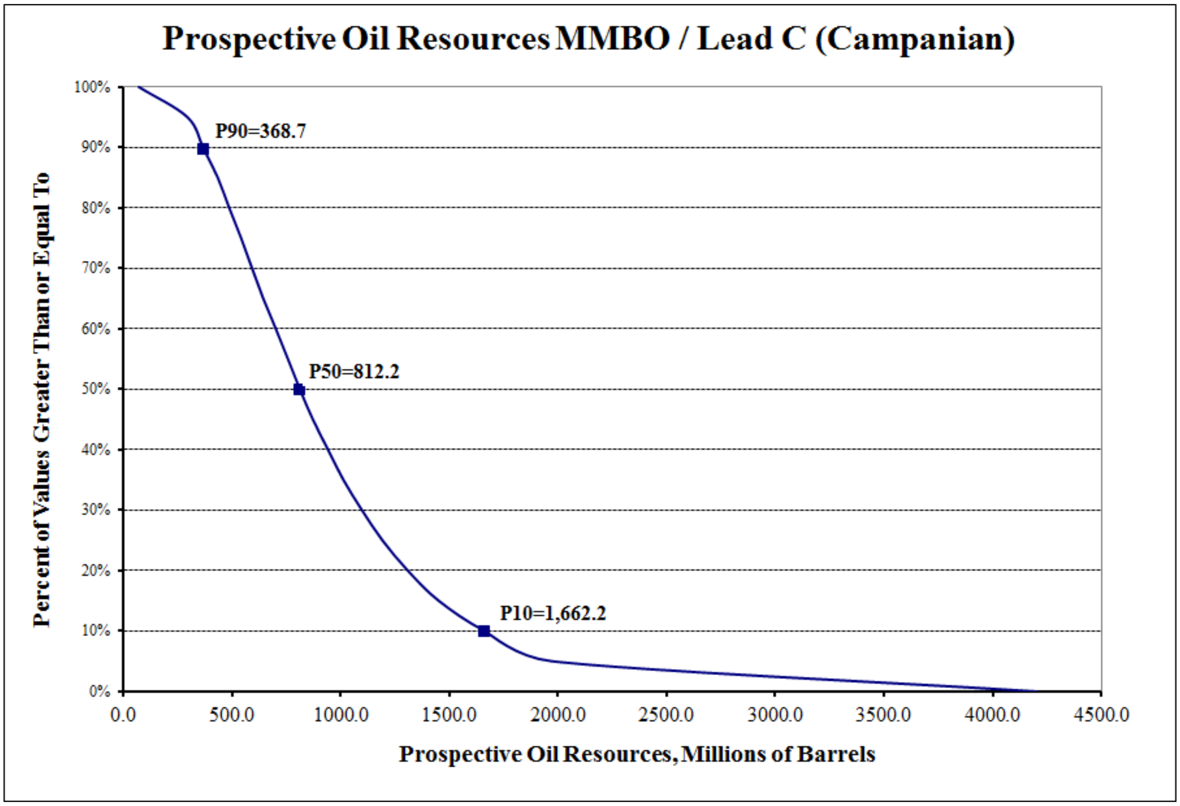


Figure 6-3 Distribution of Prospective Oil Resources, C Lead

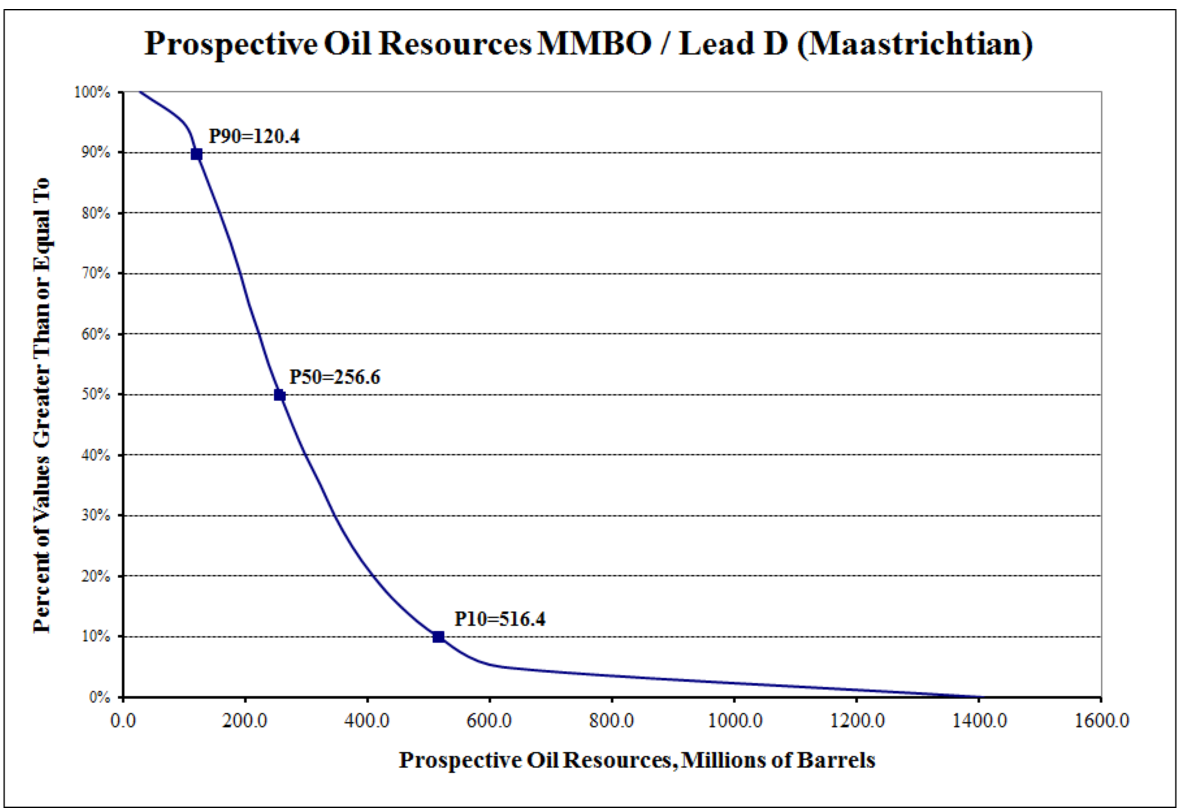


Figure 6-4 Distribution of Prospective Oil Resources, D Lead

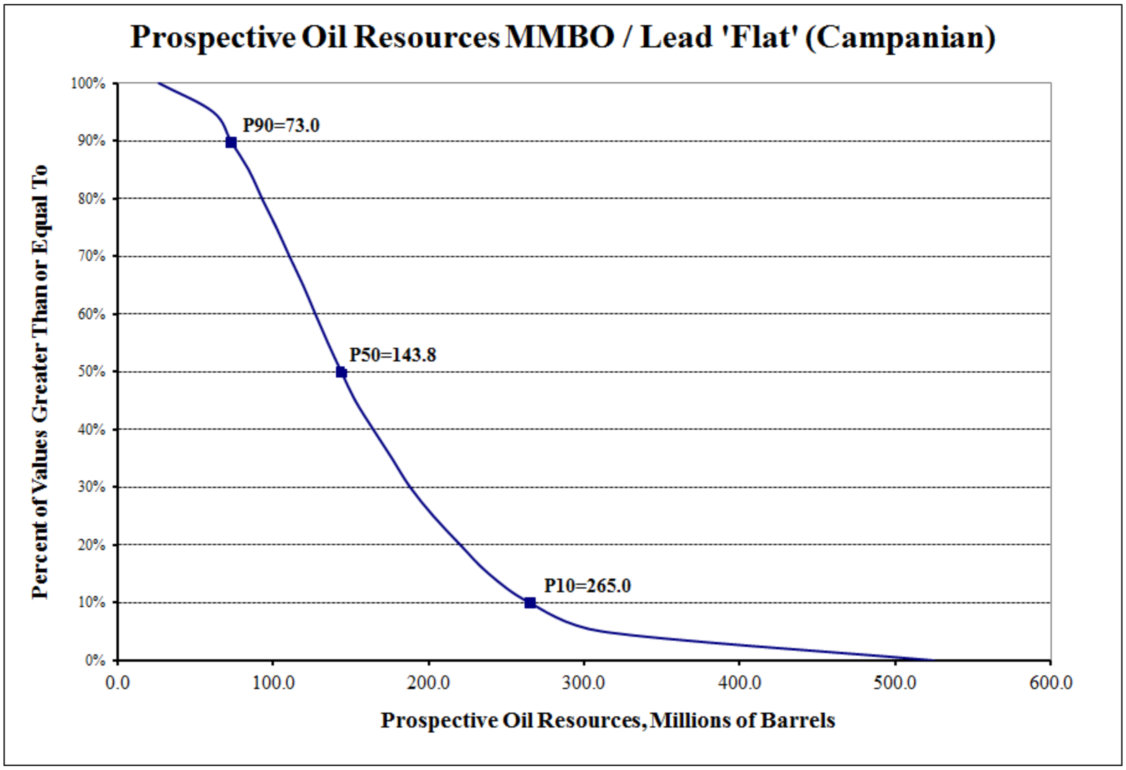


Figure 6-5 Distribution of Prospective Oil Resources, Flat Lead

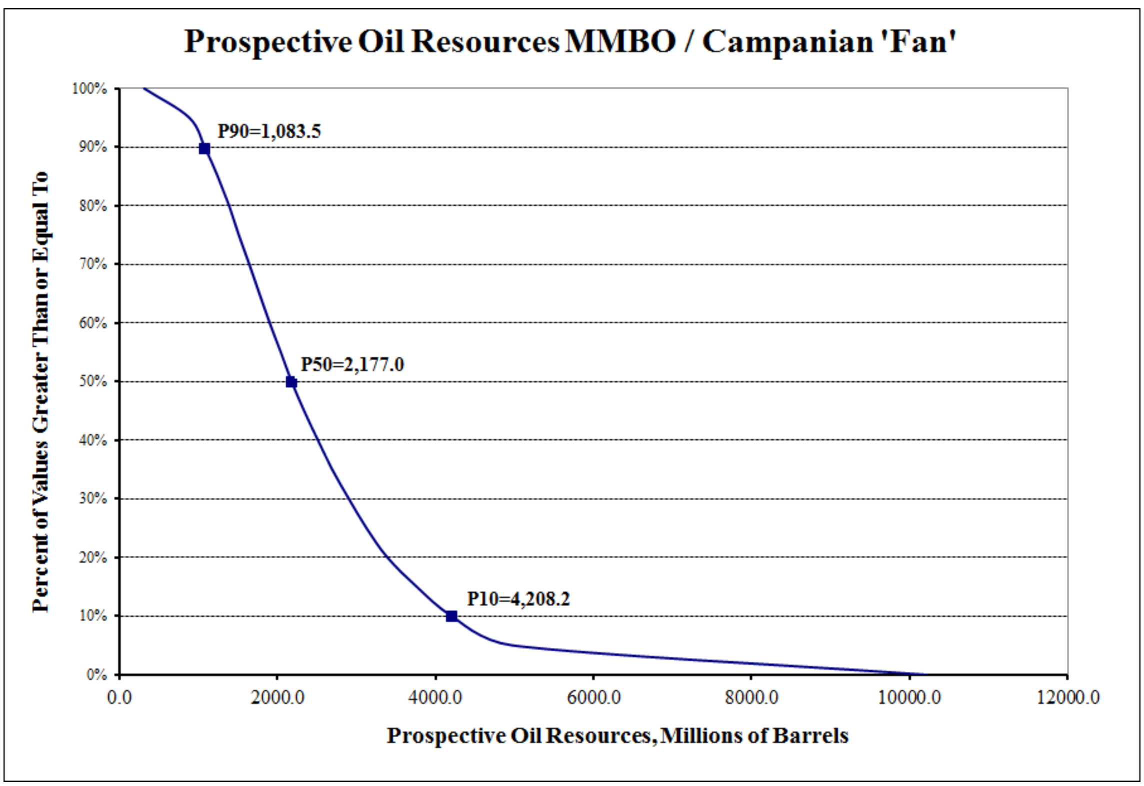


Figure 6-6 Distribution of Prospective Oil Resources, Campanian 'Fan' Lead

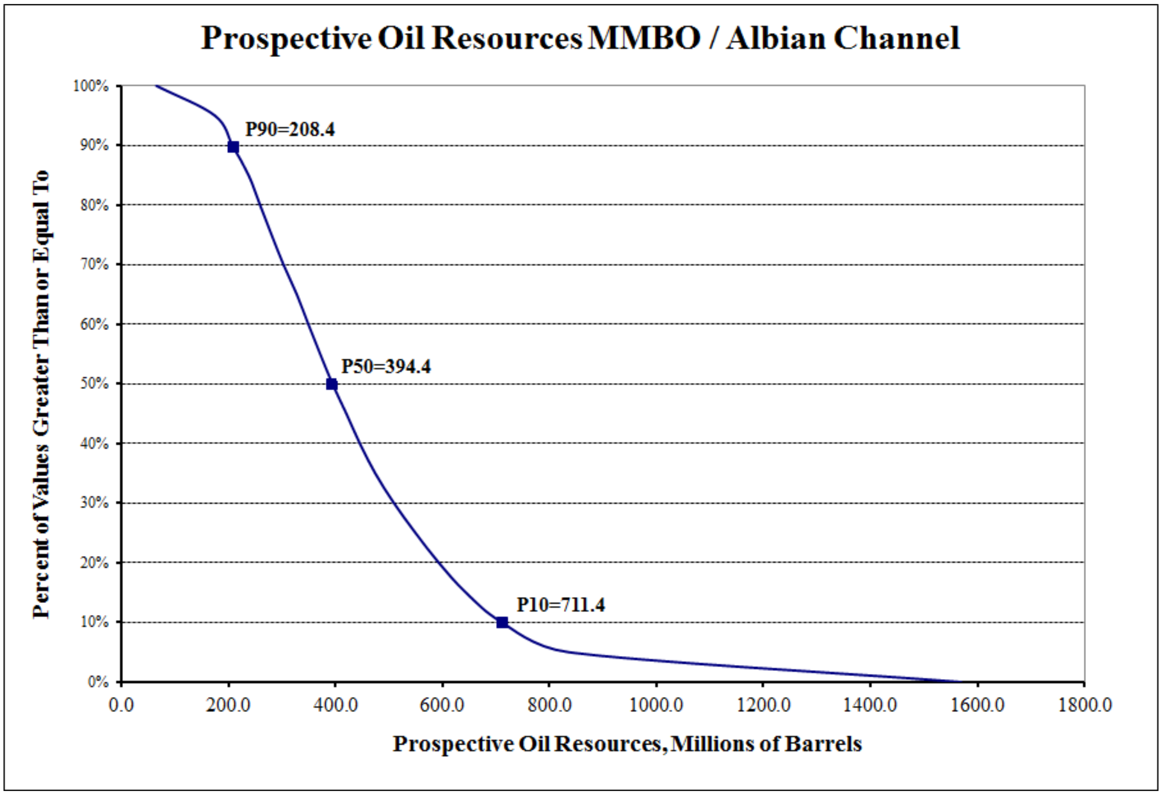


Figure 6-7 Distribution of Prospective Oil Resources, Albian Channel

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8. CONSENT LETTER

Gustavson Associates LLC hereby consents to the use of all or any part of this Lead Evaluation Report for the Cooper Block concessions, as of February 18, 2014, in any document filed with any Canadian Securities Commission by ECO Oil and Gas (Services) Namibia (PTY), Ltd or Kinley Exploration LLC.

Letha C. Lencioni
Vice-President, Petroleum Engineering
Gustavson Associates LLC

9. CERTIFICATE OF QUALIFICATION

I, Letha Chapman Lencioni, Professional Engineer of 5757 Central Avenue, Suite D, Boulder, Colorado, 80301, USA, hereby certify:

1. I am an employee of Gustavson Associates, which prepared a detailed analysis of the oil and gas properties of ECO Oil and Gas (Services) Namibia (PTY), Ltd and Kinley Exploration LLC. The effective date of this evaluation is February 18, 2014.
2. I do not have, nor do I expect to receive, any direct or indirect interest in the securities of ECO Oil and Gas (Services) Namibia (PTY), Ltd or Kinley Exploration LLC or their affiliated companies, nor any interest in the subject property.
3. I attended the University of Tulsa and I graduated with a Bachelor of Science Degree in Petroleum Engineering in 1980; I am a Registered Professional Engineer in the State of Colorado, and I have in excess of 30 years' experience in the conduct of evaluation and engineering studies relating to oil and gas fields.
4. A personal field inspection of the properties was not made; however, such an inspection was not considered necessary in view of information available from public information and records, and the files of ECO Oil and Gas (Services) Namibia (PTY), Ltd and Kinley Exploration LLC.

COLORADO REGISTERED LETHA CHAPMAN LENCIONI 29506 PROFESSIONAL ENGINEER

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