RESOURCE ASSESSMENT OF

CERTAIN P&NG HOLDINGS

OF

SIMBA ENERGY INC.

IN THE MANDERA-LUGH BASIN (BLOCK 2A)

AREA OF KENYA

(As of May 31, 2012)

Sproule

Worldwide Petroleum Consultants

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Copies:	Simba Energy Inc. Summary Volume (3 copies) Electronic (5 copies) Sproule (1 copy)

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Introduction

This report was prepared from April to June 2012, by qualified evaluators and auditors of Sproule Associates Limited ("Sproule") at the request of Mr. James W. Dick, CTO and Director, Simba Energy Inc., Vancouver, Canada. Simba Energy Inc. is hereinafter referred to as "the Company". The Company is a TSX-V listed oil and gas exploration junior focused on onshore frontier areas of Africa. This report focuses on a block within the Mandera-Lugh basin in Kenya near the juncture with the Anza basin and Lamu Embayment / Basin (Figure 1).

This report consists of an assessment of certain petroleum and natural gas (P&NG) holdings within one block in the rift system in Kenya. The Company has been granted a Production Sharing Contract (PSC) by the Ministry of Energy, Republic of Kenya and holds a 100 % working interest for Block 2A (gross 1,929,036 acres; 7,801.72 km^2) in northeast Kenya. Block 2A has sparse 2D seismic and two wells is located along the SW-NE trending Mandera-Lugh Basin (Figure 2).

This single volume report contains an Introduction, Summary and Discussion, accompanied by pertinent tables, figures and appendices. The Introduction includes Sproule's disclaimer and pertinent author certificates, the Summary presents a high-level summary of the review, and the Discussion includes our commentary pertaining to the assessment of the holdings.

The definitions used in this report are those presented in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), which are compliant with the requirements of National Instrument 51-101 ("NI51-101").

Disclaimer

This report has been prepared by qualified evaluators and auditors of Sproule Associates Limited, using current geological and engineering knowledge and techniques. It has been prepared within the Code of Ethics of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Nevertheless, the conclusions presented in this report could be affected by the data received and the procedures used by, as qualified below.

1. Property descriptions, details of interests held, technical and well data obtained from the Company or public sources were accepted as represented. No further investigation was made into either the legal titles held or any agreements in place relating to the subject properties.

2. In the preparation of this report, a field inspection of the holdings was not undertaken. Relevant geological data were made available by the Company or were obtained from either public sources or Sproule's non-confidential files.

The certificates of those evaluators involved in the preparation of this report have been included.

Assessment Procedures

In the assessment of the unproved properties, all available pertinent factors were considered, including, where applicable, bonuses paid, geological structures, prospective producing zones, historical drilling and production results, terrain and accessibility, access to infrastructure and markets, risks and the economics of exploration, development and production.

Exclusivity

This report has been prepared for the exclusive use of Simba Energy Inc., and may not be reproduced, distributed, or made available to any other company or person, regulatory body, or organization without the knowledge and written consent of Sproule, and without the complete contents of the report.

Sproule hereby gives permission to release the report for review by potential investors, the TSX-V Exchange, securities commissions and other regulatory bodies, and for the Company's anticipated annual filing on SEDAR.

Certification

Report Preparation

The report entitled "Resource Assessment of Certain P&NG Holdings of Simba Energy Inc. in the Mandera-Lugh Basin (Block 2A) Area of Kenya (As of May 31, 2012)" was prepared by the following Sproule personnel:

Original Signed by Barrie F. Jose, M.Sc., P.Geoph.

Barrie F. Jose, M.Sc., P.Geoph.
Project Leader;
Manager Geosciences / Chief Geophysicist and Partner
04 / 06 /2012 dd/mm/yr

Original Signed by Alexey Romanov, Ph.D.

Alexey Romanov, Ph.D.
Geological Reservoir Simulation Specialist and Associate
04 / 06 /2012 dd/mm/yr

Sproule Executive Endorsement

This report has been reviewed and endorsed by the following Executive of Sproule:

Original Signed by John L. Chipperfield, P.Geol.

John L. Chipperfield, P.Geol.
Senior Vice-President and Director
04 / 06 /2012 dd/mm/yr

Permit to Practice

Sproule International Limited is a member of the Association of Professional Engineers and Geoscientists of Alberta and our permit number is P6151.

Certificate

Barrie F. Jose, M.Sc., P.Geoph.

I, Barrie F. Jose, Manager, Geoscience/Chief Geophysicist and Partner of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degrees:
   a. M.Sc. Geophysics (1979) University of British Columbia, Vancouver, B.C., Canada
   b. B.Sc. (Honours) Geological Science with Physics (1977) Queens University, Kingston, ON, Canada

2. I am a registered professional:
   a. Professional Geophysicist (P.Geoph.) Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Canadian Society of Exploration Geophysicists (CSEG)
   c. Society of Exploration Geophysicists (SEG)
   d. Canadian Society of Petroleum Geologists (CSPG)
   e. American Association of Petroleum Geologists (AAPG)
   f. Petroleum Exploration Society of Great Britain (PESGB)
   g. European Association of Geoscientists and Engineers (EAGE)
   h. Indonesian Petroleum Association, Professional Division (IPA)

4. I am a qualified reserves evaluator and reserves auditor as defined in National Instrument 51-101.

5. My contribution to the report entitled "Resource Assessment of Certain P&NG Holdings of Simba Energy Inc. in the Mandera-Lugh Basin (Block 2A) Area of Kenya (As of May 31, 2012)" is based on my geophysical knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Simba Energy Inc.

Original Signed by Barrie F. Jose, P.Geoph.

Barrie F. Jose, P.Geoph.

Certificate

Alexey Romanov, M.Sc., Ph.D.

I, Alexey Romanov, Senior Geologist and Reservoir Simulation Specialist and Associate of Sproule, 900, 140 Fourth Ave. SW, Calgary, Alberta, declare the following:

1. I hold the following degrees:
   a. Ph.D.Eng. (2007), KazanState Technological University, Kazan, Russia
   b. M.Sc. Reservoir Evaluation and Management (2004), Heriot-WattUniversity, Edinburgh, UK
   c. M.Sc. (Honours),Petroleum Geology (2003), KazanState Technological University, Kazan, Russia

2. I am a member of the following professional organizations:
   a. Society of Petroleum Engineers (SPE)
   b. Association of Professional Engineers and Geoscientists of Alberta (APEGA)

3. My contribution to the report entitled "Resource Assessment of Certain P&NG Holdings of Simba Energy Inc. in the Mandera-Lugh Basin (Block 2A) Area of Kenya (As of May 31, 2012)" is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

4. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Simba Energy Inc.

Original Signed by Alexey Romanov, M.Sc., Ph.D.

Alexey Romanov, M.Sc., Ph.D.

Certificate

John L. Chipperfield, B.Sc., P.Geol.

I, John L. Chipperfield, Senior Vice-President, and Director of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. B.Sc. (Honours) Geology (1972) University of Alberta, Edmonton AB, Canada

2. I am a registered professional:
   a. Professional Geologist (P.Geol.) Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Canadian Society of Petroleum Geologists (CSPG)
   c. American Association of Petroleum Geologists (AAPG)
   d. Society of Petroleum Engineers (SPE)
   e. Canadian Well Logging Society (CWLS)
   f. Ontario Petroleum Institute (OPI)

4. I am a qualified reserves evaluator and reserves auditor as defined in National Instrument 51-101.

5. My contribution to the report entitled "Resource Assessment of Certain P&NG Holdings of Simba Energy Inc. in the Mandera-Lugh Basin (Block 2A) Area of Kenya (As of May 31, 2012)" is based on my geological knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Simba Energy Inc.

Original Signed by John L. Chipperfield, P.Geol.

John L. Chipperfield, P.Geol.

Summary

This report is based on interpreted technical data including geological maps, well logs and cross-sections, engineering materials and other information obtained from the Company, publications or Sproule's non-confidential files and our personal knowledge of the economics of oil and gas exploration, development and production in this general area of Africa. Sproule has conducted other resource assessments on blocks within the Anza and Mandera basins.

A summary of the P&NG holdings reviewed in this report is presented in Table S-1.

Table S-1
Summary of Unproved Properties,
Mandera-Lugh Basin, East African Rift System, Kenya
As of April 30, 2012

Block	Basin	Working Interest %	Partner	Total Lands Gross Acres	Total Lands Net Acres	Total Lands Gross km^2	Total Lands Net km^2
Block 2A	Mandera-Lugh	100		1,929,036	1,929,036	7,802	7,802
Total				**1,929,036**	**1,929,036**	**7,802**	**7,802**

Notes:
1 Block 2A - The Production Sharing Contract for Block 2A was signed in August 2011and became effective in November 2011. The exploration period consists of three terms totaling seven years commencing on the effective date. Any production period resulting from a declaration of a commercial discovery would extend for up to 25 years. The work program includes both 2D and 3D seismic data acquisition of and one [1] well commitment in the initial exploration term. Government participation is 20%.

The Production Sharing Contract for Block 2A was signed in August 2011 and became effective in November 2011. The exploration period consists of three terms totaling seven years commencing on the effective date. Any production period resulting from a declaration of a commercial discovery would extend for up to 25 years.

During the Initial Exploration Period of two (2) contract years, the exploration program will include data gathering and reviewing: technical reports, satellite images, and interpretation of existing 2D seismic, gravity and magnetometer as well as carry out block-wide field geological and geochemical studies.

In the second year, the Company is to reprocess the existing 2D seismic data and acquire 1,700 measuring points of passive seismic data to cover area over 2750 km^2 and/or acquire 2D seismic data and/or acquire 3D seismic data.

To date the company has completed an environment assessment study. A 4000 km2 passive seismic survey is planned for mid June 2012. A geochemical survey will be conducted in conjunction with this survey.

Table S-2
Resource Summary
Block 2A, Mandera-Lugh Basin, East African Rift System, Kenya
As of April 30, 2012

		Gross Unrisked Undiscovered Petroleum Initially In-Place [1], MMboe				Gross Unrisked Prospective Resources [2], MMboe				Geological COS[3]	Gross Risked Mean Prospective Resources[4], MMboe
			Low Estimate	Best Estimate	High Estimate		Low Estimate	Best Estimate	High Estimate		
Lead	Zones	Mean	P90	P50	P10	Mean	P90	P50	P10	%	Mean
1	Ken 5	507.2	61.3	279.4	1186.6	117.2	11	55.8	272.6	9.0	10.5
	Syn-Rift 2	413.5	48.5	224.4	969.7	95.5	8.73	45.1	221.8	4.0	3.8
	Syn-Rift 1	326.4	27.4	152.7	778.2	75.4	4.98	30.5	181.3	2.0	1.5
2	Ken 5	180.9	21.9	99.7	423.3	41.8	3.94	19.9	97.3	9.0	3.8
	Syn-Rift 2	128.7	11.6	62	306.8	29.8	2.09	12.4	71.3	4.0	1.2
	Syn-Rift 1	98.3	14.6	59.3	219.9	22.7	2.57	11.8	53.2	2.0	0.5
3	Ken 5	272.1	41.5	165.5	615.8	62.9	7.32	32.9	146.4	9.0	5.7
	Total	**1927.1**				**445.3**					**26.9**

Ken 5 – Triassic [Mansa Guda reservoirs (Mariakani / Maji ya Formations?)]
Syn-Rift 2 (Ken 3?) – unpenetrated locally, age uncertain; Permian Zechstein/Rotliegende?; Wajir/Karoo Formation?
Syn-Rift 1 – unpenetrated locally, age uncertain; early Permian Rotliegende?; Karoo Formation?

Notes:

1 Undiscovered resources (equivalent to undiscovered petroleum initially-in-place) are those quantities of petroleum that are estimated, as of a given date, to be contained in accumulations yet to be discovered.

2 Prospective resources are 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 (geological chance of success) and a chance of development (economic, regulatory, market and facility, corporate commitment and political risks). The chance of commerciality is the product of these two risk components. These estimates have not been risked for either chance of discovery or chance of development. There is no certainty that any portion of the prospective resources will be discovered and, if discovered, there is no certainty that it will be developed or, if it is developed, there is no certainty as to either the timing of such development or whether it will be commercially viable to produce any portion of the resources. These are gross estimates without consideration of working interest, royalties, or other encumbrances.

3 Individual geological risks were applied to each zone. The risks were aggregated statistically within the Monte Carlo software, *GeoX* at the individual prospect entity level. In this way, leads with multiple potential target zones have an overall higher chance of geological success. These aggregate risk numbers apply only to the chance of obtaining a minimum amount of hydrocarbons from at least one zone to fall on the prospective resource distribution curve. It is not statistically appropriate to apply these chance of geological success numbers to the low, best, and high estimates.

4 These are gross estimates without consideration of working interest, royalties or other encumbrances.

Two additional exploration periods of two (2) contract years each, require a commitment to acquire, process and interpret 500 kilometres of 2D and/or equivalent 3D seismic data and/or equivalent passive seismic and drill one (1) exploratory well to a minimum depth of 3000m. The initial production sharing arrangement is a 50 - 50 percent split with the Kenya government.

No proved, probable or possible reserves have been assigned to these lands at this time, and they have been assessed as unproved properties containing prospective resources. There is no certainty that any portion of these resources will be discovered and, if discovered, there is no certainty that it will be commercially viable to produce any portion of these resources.

The available 2D seismic was provided to Sproule, but the Company's interpretation was not. The seismic has been independently interpreted by Sproule to identify prospectivity on Block 2A.

Block 2A is quite faulted and has been the focus of significant geophysical interpretation by Sproule. Three leads have been mapped at four representative seismic horizons. Five horizons have been carried in the interpretation. The youngest of these, Ken 6 in terminology used within the area, is interpreted to be lower Jurassic (Liassic) in age. Four other deeper seismic markers of uncertain age were also carried. In succession from youngest to oldest, the horizons are Ken 5? (Triassic?), Syn-Rift Marker 2, Syn-Rift Marker 1 and Basement.

Three leads have been mapped seismically at these levels. In conjunction with areas defined on these horizons and reservoir parameters defined from possible analogs, low, best, and high estimates of undiscovered petroleum in-place have been calculated. The outcomes from the various leads have been statistically aggregated.

The Company's exploration plans for Block 2A include the following:

- GeoDynamics S.R.L. of Italy has been contracted to conduct an Infrasonic Passive Differential Spectroscopy (IPDS) seismic survey covering 4000 km^2 with 250 measurement points on a variable spacing beginning mid-June 2012;
- The potential areas identified by the passive micro-seismic survey will be further evaluated by conventional seismic, most likely 3D or 2D and/or gravity gradiometer, prior to selecting a drill site;
- An additional 1000 kilometres of 2D seismic and/or equivalent 3D seismic data and/or equivalent passive seismic is planned for Block 2A;
- Based upon the results of the seismic programs, a drilling program to evaluate the leads will be designed.

Sproule has reviewed the technical data and the Company’s exploration plans related to these holdings, and it is our opinion that

- The holdings are prospective and justify the Company's plans to further delineate them with additional passive micro-seismic, 2D or 3D seismic, and gravity gradiometer surveys;
- The proposed program constitutes a reasonable and prudent approach to the exploration and possible future development of these lands.

In reviewing the properties, we have taken into account all known available pertinent factors, such as geological structures, prospective producing zones, historical exploration and development activity, terrain, accessibility, access to infrastructure and markets, operating status of the lands, acquisition costs and anticipated program costs.

Discussion

1.0 Introduction

Simba Energy Inc. is a TSX-V listed oil and gas exploration junior focused on onshore frontier areas of Africa. Its original focus was on West Africa, but its focus has been extended to east Africa. Its portfolio comprises onshore PSCs in Kenya and Guinea and potential onshore PSCs in Mali, Liberia and Ghana.

The Company's lands are shown in Figures 2 and 3. It currently holds a 100-percent interest in Block 2A in the Mandera-Lugh Basin in East Kenya. The gross and net land holdings are provided in Table S-1. These holdings are the subject of this report.

Two wells, Elgal-1 and Elgal-2, were drilled in 1987 within Block 2A into a structural high on the north side of the major regional Lugh-Bogal fault which defines the northeast margin of the Anza basin (Figure 3). Figure 3 also shows the extent of the Company's 2D seismic control. The Elgal wells encountered only a very thin condensed section of older strata overlying this high. Other nearby wells drilled to the south within the Anza basin (Hothori-1 in Block 2B and Anza-1, Endela-1, Bahati-1 and Meri-1 in Blocks 3A and 3B) encountered a thicker succession of younger strata (Figures 3 and 4). The major Lugh-Bogal fault is also clearly defined on a superimposed Bouguer gravity map (Figure 5).

Three prospective leads have been defined by Sproule within Block 2A on the basis of an independent seismic interpretation.

No proved or probable reserves have been assigned to these holdings at this time. The holdings have been assessed as unproved properties.

The following discussion presents the regional geological setting, the independent geophysical interpretation and the results of the prospective resource assessment on Block 2A.

The Company has already contracted GeoDynamics S.R.L. of Italy to conduct an infrasonic passive differential spectroscopy (IPDS) seismic survey beginning mid-June 2012. Conventional 2D or 3D seismic and possibly gravity gradiometer surveys will be used to further evaluate potential areas identified by the passive micro-seismic survey. A drilling program will follow based upon the results of these geophysical surveys.

The accompanying figures and diagrams were provided by the Company or generated by Sproule during our interpretation, or the source is otherwise identified.

2.0 Geological Setting

The Company holds the Production Sharing Contracts to Block 2A of Kenya, as shown in Figures 2 and 3. Block 2A is located within the Mandera-Lugh Basin, on the north side of the juncture of the three basins (the Anza basin, the Mandera-Lugh basin and the Lamu basin/embayment). The Mandera Basin is the southern termination of the Ethiopian/Somalian Ogaden Basin, as shown in Figure 4.

The Mandera-Lugh Basin (Figures 1 and 2) occupies part of the northeastern territory of Kenya and extends to Somalia and Ethiopia. The basin is a failed rift which developed from the Carboniferous to Upper Jurassic. It is filled with continental and marine sediments with evaporitic episodes occurring in the Jurassic. The basin initially developed as an intracratonic rift graben in Permian to Lower Jurassic time and, later in the Jurassic, transformed into an open, broad marine basin dominated by platform carbonate deposition. The initial rift phase in the Mandera-Lugh basin was dominated by continental fluvial and lacustrine depositional systems. The Jurassic platform carbonate build-up phase that commenced later in the Lower Jurassic continued until at least the close of the Jurassic and probably into the Lower Cretaceous, after which continental conditions were re-established. Cretaceous basin fill consists of continental fluvial sediments with deltaic and aeolian influences. The basin is truncated on its southern margin by the Anza basin that became an active extensional rift in the Lower Cretaceous, terminating any further tectonic extensional activity in the Mandera-Lugh basin.

The Anza Basin in located in northeastern Kenya and is a northwest trending rift basin, the failed arm of a triple junction that formed in the Late Cretaceous. The northeastern boundary is the Lagh-Bogal fault, a major regional fault down-dropped to the southwest. The basin has three segments: the South Anza Basin, the North Anza Basin and the North Anza Basin Extension, each of which experienced significantly different structural and stratigraphic histories. The north and south segments are divided by a series of listric faults in a transform zone, and the division for the north extension is marked by the Mount Marsabit volcanic cone. The three sub-basins become progressively deeper from north to south as the Anza Basin plunges southeast toward the Lamu Basin. The South Anza Basin has the thickest sedimentary column of the three segments. Analogies can be made to the rifted Muglad Basin in Sudan, which has significant oil production. Source rocks that are equivalent to the tar sands and heavy oil accumulations in Madagascar have been identified at the Permian-Triassic boundary. A generalized stratigraphic table for all three basins is summarized in Figure 6, from MacKeith et al.

2.1 Tectonic History

Pre-rift to Initial Rift Period

Following the first break-up of the Panafrican craton at the end of the Carboniferous, an initial rift stage occurred, initiating the northeastern branch of the Mandera-Lugh basin and the southern branch of the Lamu basin (Figure 7 A). The rifting continued through the Permian and Triassic, with the deposition of coarse clastic sediments corresponding to the Wajir sandstone/Elgal shale in the Mandera-Lugh Basin and Taru and Mariakani sandstones in the Lamu Basin (Figure 7 B).

Syn-rift Period

A second rift episode occurred during the Jurassic, which marked the beginning of the separation between Madagascar and Africa and the creation of a seaway between the two landmasses. Transgression of this rift led to the deposition of marine Didimtu limestones in both the Lamu and the Mandera-Lugh basins (Figure 7, C and D). During this period, Madagascar drifted away from Kenya and rifting activity ceased in the Mandera graben.

Post-rift Period

During the Middle and Upper Jurassic, the Proto-Indian Ocean was opening and marine conditions prevailed in the Mandera-Lugh and Lamu basins, leading to the deposition of marine sediments such as evaporites and limestones in both basins (Figure 8, E, F and G). The marine conditions ceased with the occurrence of an uplift phase of the Mandera area towards the end of the Jurassic and Early Cretaceous by the deposition of the Marehan sandstone (Figure 8 H). The Anza Graben truncated the Mandera-Lugh basin to the southeast and led to the continental fluvial-lacustrine sedimentation in the whole graben (Figure 8 I and J).

2.2 Regional Stratigraphy

The structural and stratigraphic evolution of Kenya has been described by Kerr, MacKeith, Nyagah and Ngenoh (1997) and by Beicip-Franlab (2005).

The oldest sediments in the study area are the very coarse-grained fluvial sandstones of Permian age that were deposited in all four basins. Fluvial sands continued to fill the basins during the Triassic. Of particular interest is the Elgal shale, which may be equivalent to the Maji ya Chumvi shale in the Lamu basin. The Elgal shale penetrated in the Elgal wells, is between 425 and 670 m thick and is believed to be over-mature and in the dry gas generation window. The overlying Wajir sandstone ranges in thickness between 450 and 1,800 m.

The Lower Jurassic Mazeras is fluvial sandstone in the Lamu basin that is equivalent to the Mansa Guda sandstone in the Mandera-Lugh and Anza basins. It is a coarse-grained arkosic sandstone with porosity between 10 and 15 percent. Biodegraded oil has been found in the Mansa Guda near Tarbaj, approximately 75 km northeast of the Elgal-2 well. The Tarbaj oil seep appears to be at the up-dip subcrop of an easterly plunging structural nose mapped by Sproule on the limited Block 1 seismic. The sandstone grades vertically and laterally into lagoonal limestone and mudstone of the Rare limestone and, farther seaward, to evaporites. Transgression during the Middle and Upper Jurassic deposited carbonates that are more than 1,500 m thick in the three basins. Oil-filled fractures in the Murri Formation have been documented from an outcrop east of Tarbaj.

Regression during the Lower Cretaceous resulted in the deposition of clastic sediments. The Ndovu-1 well in the Anza Graben encountered 2,500 m of alternating sands and shales, resulting in 822 m of net sand with porosity greater than 8 percent, averaging 15.8 percent.

Several wells have penetrated the Upper Cretaceous in the study area, encountering fluvial to deltaic, medium-grained, porous sandstones with thicknesses ranging from 280 to 1,200 m. The Ndovu-1 well encountered tar in Upper Cretaceous sandstones.

Paleocene and Eocene sediments were deposited in a brackish to near shore marine environment. Based on the four wells that have penetrated this megasequence in the study area, the zone has a thickness between 1,400 and 2,000 m. The sandstones have porosities between 15 and 22 percent.

Miocene rocks in the area are dominated by continental sandstones and shales that are 500 to 900 m in thickness. The sandstones have porosities in the low 30 percent range.

2.3 Exploration History

Petroleum exploration in Kenya has been sporadic and is divided into five phases, 1954-1971, 1971-1976, 1976-1985, 1985-1996 and 2000-present.

Phase 1: 1954-1971

Petroleum Exploration in Kenya begun in the 1950s with the first well being drilled in 1960. A consortium of BP and Shell began exploration in Kenya in 1954 and continued until 1971. Their efforts were concentrated in the northern part of the Lamu Basin, where they drilled a total of 10 wells. The BP-Shell program included extensive geological field work, seismic and gravity data acquisition and stratigraphic tests. Despite several indications of oil staining and untested zones with gas show, none of the wells were fully evaluated or completed for production. The Dodori-1 well tested gas at 3.1 mcf/day from Paleocene Kofia sands. The Pate-1 well kicked during drilling and flowed wet gas, mud and water from a porous sand near total depth.

Closer to Block 2A, Frobisher Ltd., Adobe Oil Company and Burmah Oil Company conducted photo geological field geology, gravity, aeromagnetic and seismic surveys in the Mandera basin, but no drilling was undertaken.

Phase 2: 1971-1976

This second phase of drilling was mainly located in the northern part of the Lamu Basin. Texas Pacific drilled the Hagarso-1 well in 1975 and encountered oil and gas show in Cretaceous rocks. Other companies that conducted studies, but did not drill, included Whitestone, Sun Oil, Canadian Superior, Wainoco and Anshutz.

In 1976, Chevron and Esso drilled the Anza-1 and Bahati-1 wells in the southern part of the Anza Graben after an extensive seismic program. Both wells were dry and had ambiguous results. The drilling mud of both tests was suspected of having hydrocarbons and microfossils that contaminated the geochemical and cuttings respectively. At Anza, no closure is thought to be present at either the Cretaceous or Jurassic. Late movement on the faults in that area occurred during the Lower Tertiary and could have breached any potential traps.

Phase 3: 1976-1985

The first well offshore Kenya, Simba-1, was drilled by Total in 933 m of water. Another two wells, Maridati-1B and Kofia-1, were drilled by a consortium of Cities Services, Marathon and Union. Although the results of these wells were disappointing, the seismic data revealed that salt diapiric structures were present along the Kenyan margin. The presence of salt diapirs could provide numerous drape features and pinchouts, favourable for hydrocarbon traps.

Phase 4: 1985-1996

The Kenyan government revised the petroleum exploration and production legislation in 1986 in an attempt to attract international exploration. In 1986, Petro-Canada International Assistance Corporation conducted new seismic and drilled the KenCan-1 well, which was abandoned at 3,863 m in Precambrian basement. Due to the new legislative framework in Kenya and the discovery by Chevron of large oil accumulations in the Abu Gabra rift of

Sudan, a fourth phase of exploration, mainly in the Anza Graben which appears to be on strike with the Sudan rifts, was stimulated. A group of companies led by Amoco and Total drilled ten exploratory wells within seven years. Total exploration drilled Ndovu-1, Duma-1 and Kaisut-1 in North Anza Basin, while Amoco drilled Sirius-1, Bellatrix-1 and Chalbi-3 in the northwest of the Anza basin and Hothori-1 in the south of the Anza basin. All these wells were abandoned but indicated shows of oil and gas.

Phase 5: 2000-Present

In spite of many oil and gas shows, there have still not been any commercial discoveries in the onshore basins in Kenya with the possible exception of the recent discovery by Tullow. Production sharing contracts in both offshore and onshore have been awarded to various companies (Figure 1). The Bogal-1 well was recently drilled by CNOOC and African Oil Corp in Block 9 immediately to the northwest of Block 2B. The total depth of the well was 5,085 m within the Cretaceous. Information released thus far suggests 91 metres of gas pay in the Lower Cretaceous, and the well is not believed to have penetrated the Jurassic.

Recent drilling success by Tullow to the northwest in the Anza in the basin has spared further exploration interest in the East African rift basins. On May 7 2012, Tullow announced over 100 metres of pay within several reservoir zones in its Ngama-1 well which is appreciably more that encountered in any of our East African exploration wells to date. The well is being deepened to other reservoir targets and will be drilled to a depth of approximately 2,700 m. On May 25 2012, it was further announced that they had encountered oil and gas shows over a gross interval of 140 metres from a depth of 1,800 metres to 1,940 metres.

Seven PSCs were signed in the offshore Lamu Embayment between 2000 and 2002. Woodside collected 7,884 km of 2D in the offshore in 2003. This offshore area is currently undergoing very active exploration.

2.4 Well Summary

Figure 9 shows a historical summary of all deep wells drilled in Kenya. A summary of previous wells drilled near to Block 2A are provided in the following discussion. The Simba 2D seismic grid has one key line crossing the Elgal-1 and Elgal-2 wells and has some seismic extending off Block 2A south to the Hothori-1 well in the Anza basin that is of lesser importance to the prospectivity within the Mandera-Lugh basin on Block 2A (Figure 3). All other wells discussed below fall outside of both Block 2A and the Company's seismic control but are mentioned due to their reservoir implications and hydrocarbon shows.

Elgal-1 and Elgal-2

These two exploratory wells were drilled north of the major regional Lagh-Bogal fault near the western edge of the Mandera-Lugh Basin to evaluate the hydrocarbon potential of the Permian Karoo (Ken 3) sequence at shallow depths. The Elgal-1 well reached a total depth of 1,280 m in the Karoo and the Elgal-2 well reached a total depth of 1,908 m in the Triassic with thin Tertiary cover on the up thrown high. Both wells were prognosed to drill to approximately 2,134 m but the geochemical data acquired during drilling indicated that the Permo-Triassic sequences were over-mature. Both wells encountered quartzitic sandstones with almost no reservoir development potential.

Anza-1

The Anza-1 well was drilled in a complexly faulted horst and graben area to test Cretaceous targets on a structurally controlled closure and reached a total depth of 3,662 m in the Upper Cretaceous. No closure is evident at either the Cretaceous or Jurassic Sproule mapping of the seismic data at the target zone depth. Inspection of seismic profiles suggests that latest movement on the faults occurred during the Lower Tertiary and could have breached any potential traps.

Minor gas shows were reported in the Paleocene. Good porosity occurs in Miocene, Eocene and Upper Cretaceous sands. Low total organic carbon (TOC) values were reported throughout the well.

Bahati-1

The Bahati-1 well was drilled with good quality seismic data on what is reported to be a closed fault-dependent Cretaceous feature resulting from strike-slip movement and reached a total depth of 3,421 m in the Upper Cretaceous. Poorly consolidated fluvial-deltaic or lacustrine sands were penetrated in the Upper Cretaceous and Quaternary sections. Good porosity was encountered in Eocene and Miocene sands.

Endela-1

The Endela-1 well was drilled in a graben suggested to be a continuation of the Abu Gabra Rift from Sudan, in which oil has been discovered by Chevron in Lower Cretaceous sands. It was drilled to evaluate the potential of the Paleogene sequence on a seismically defined structure. Seismic banding, believed to be attributed to a sand/shale environment similar to the seismic banding associated with the productive areas in Sudan was observed in the Paleocene. The well reached a total depth of 2,780 m in the Middle Eocene. Methane was reported from 2,409 to 2,779 m. Good porosity was encountered in Neogene and Paleogene sands. On the Sproule mapping, Endela-1 did not target a structural closure.

Hothori-1

The Hothori-1 well was drilled to evaluate the Lower Tertiary and Cretaceous on a seismically defined faulted anticlinal feature caused by listric and strike-slip faults. It reached a total depth of 4,394 m in the Lower Cretaceous. Gas shows were reported in the Lower Tertiary and the Upper Cretaceous. Fluorescence in sandstone cuttings from the Tertiary Paleogene suggested the presence of liquid hydrocarbons. Several RFTs and a DST were conducted, but no hydrocarbon recoveries were reported. The Hothori-1 well is not thought to have penetrated the crest of the structure on the Sproule seismic interpretation.

Meri-1

Meri-1 well was drilled to test a structural high, probably underlain by a basement high, defined exclusively by gravity data. It reached a total depth of 1,941 m in the Paleocene and penetrated the Barren Beds deposited in marginal marine and deltaic environments. No shows of oil and gas were reported.

2.5 Petrophysics

Sproule conducted a petrophysical analysis for the available wells in the area using the PRIZM petrophysical module in Landmark’s PC-based Geographix software. The objective of the analysis was to determine effective porosity, water saturation and net pay thicknesses.

Volume of Shale

The volume of shale was estimated from the GR log using the following equation:

$$Vsh_{GR} = 0 < \frac{(GR - GR_{clean})}{(GR_{shl} - GR_{clean})} < 1$$

Where

Vsh_{GR} is the volume of shale from gamma ray log,

GR is the gamma ray value of the formation in API units,

GR_{clean} is the clean matrix gamma ray value,

GR_{shl} is the gamma ray value in shale.

The shale volume was then used in the calculation of effective porosity and water saturation.

Effective Porosity

The effective porosity was calculated from Sonic log corrected for the estimated volume of shale.

The sonic porosity equation used in the analysis is as follows:

$$\phi_s = \frac{1}{CMP} * \frac{(\Delta T_{\log} - \Delta T_{ma})}{(\Delta T_{fl} - \Delta T_{ma})}$$

Where

CMP is compaction coefficient applied to young unconsolidated rocks,

ΔT_{log} is recorded travel time,

ΔT_{ma} is matrix travel time,

ΔT_{fl} is fluid travel time.

Finally, the effective porosity (PHIE) was calculated by correcting for the estimated volume of shale within the formation, using the equation:

$$\phi_e = \phi_s (1 - V_{sh})$$

Where

ϕ_e is the effective porosity,

ϕ_s is the sonic porosity,

V_{sh} is the volume of shale.

Figure 10 shows the path of a south-north structural cross-section (Figure 11) extending from the Lamu Basin, through the southern portion of the Anza Basin and up onto the high of the Mandera-Lugh Basin where the Elgal-1 & -2 wells were drilled. There is no shortage of potential sand reservoirs in the system. Wells to the south, in the Lamu Basin, tend to have thicker shale intervals, which could provide effective top seals. In Block 2B near Hothori-1, sands are still very abundant and are inter-bedded with thin shales. The Elgal-1 and -2 wells were drilled within Block 2A on the northern upthrown side of the major Lagh-Bogal Fault and encountered thin Tertiary overlying Triassic over-mature clastics.

Ranges of reservoir parameters used in this study were derived from Sproule's petrophysical analysis and are summarized in Figure 12.

3.0 Geophysics

This discussion addresses Sproule's independent geophysical interpretation of Block 2A, and the identification of three prospective leads. Overviews of the block, well control, Landsat, topographic elevation and surface geology are provided in Figures 11-13.

3.1 Block 2A, Mandera-Lugh Basin

Data Control

Figure 3 shows a detailed view of the 2D seismic and well control in the vicinity of Block 2A. The seismic is of variable quality but generally quite poor. The predominant drainage to the southeast is evident on the digital elevation (DEM) images (Figure 14) and Landsat (Figure 15). The dominant trends observed are northwest-southeast.

Fault Framework

Faulting in these East African rift basins tends to be semi-parallel to the basin axis with fault-dependent closures against a series of elongated horsts and grabens. Block 2A lies at the northern juncture of the Anza basin with the Mandera-Lugh basin (Figure 4). Faulting observed within the block reflects the direction of both the major regional Lagh-Bogal bounding fault on the northeast margin of the Anza basin and faulting semi-parallel to the axis of the Mandera-Lugh basin (Figure 16).

Horizon Interpretation

The quality of the 2D seismic is quite variable but it exhibits a reasonable degree of reflection continuity. Distinctive amplitude packages can be seen as seismic facies "banding" and can be carried between lines, helping to define the major stratigraphic packages. Sproule has mapped leads on three principal stratigraphic units and used these, in conjunction with the petrophysical parameters (Figure 10), to estimate the undiscovered petroleum resources.

A 3D Petrel structural model has been generated to honour the horizon picks and fault framework at the Ken 6, Ken 5, Syn-Rift-2, Syn-Rift-1, and Basement surfaces. Closure areas from Ken 5, Syn-Rift-2, and Syn-Rift-1 surfaces have been used in the assessment.

These surfaces are identified as follows:

- Ken 6 Lower Jurassic Liassic (Kalicha-Murri-Didimtu)
- Ken 5 Triassic (Mansa Guda reservoirs [Mariakani/Maji ya Formations?])
- Syn-Rift 2 unpenetrated locally, age uncertain; Permian Zechstein/Rotliegende?; Wajir/Karoo Formation?
- Syn-Rift 1 unpenetrated locally, age uncertain; early Permian Rotliegende?; Karoo Formation?
- Basement

The three key horizons are shown on the stratigraphic column of Figure 13. Time structure maps are provided for each of these horizons

The exact age of the deeper Syn-Rift 2 and Syn-Rift-1 seismic markers remain uncertain, as they have not been penetrated in local wells.

Three separate structural leads have been identified and have been labeled Lead 1, Lead 2 and Lead 3 from west to east. From the sparse 2D seismic control, closures have been identified on both Lead 1 and Lead 2 at all three mapped horizons (Ken 5, Syn-Rift-2 and Syn-Rift-1). Lead 3 only has closure identified on the shallower seismic marker (Ken 5). It is expected that the leads will change shape and size as additional seismic control is obtained.

The Tarbaj oil seep is located immediately north of Block 2A (Figure 10), suggesting the presence of an active petroleum system with oil migrating updip and being biodegraded upon contact with meteoric waters near surface.

4.0 Petroleum Systems and Risk

The following discussion addresses the available evidence of active petroleum systems in the study area.

Source Rocks

Potential source rocks in the study area may occur in four main stratigraphic intervals (youngest to oldest):

- The youngest possible source is the Tertiary. Figure 7, from Kerr, MacKeith, Nyagh and Ngenoh (1997), shows two samples in the study area with TOC in excess of 2 percent and hydrogen index values in excess of 250 mg HC/g TOC. Hydrocarbons would have to migrate laterally from the shallower portion of the Mandera-Lugh basin to the east and down to the older reservoirs identified in Leads 1, 2 and 3.
- The thick Lower Cretaceous shale penetrated by the Hothori-1 well is also a good potential source rock. Hydrocarbons would have to migrate laterally from the shallower portion of the Mandera-Lugh basin to the east and down to the older reservoirs identified in Leads 1, 2 and 3.
- An important source may also occur within Upper Jurassic rocks. Elsewhere in Kenya, the Upper Jurassic Mtomkuu Formation (Ken 8) is very shaly and could be a potential source rock. This source would still be younger than the shallowest Ken 6 horizon mapped over Leads 1, 2 and 3. These potential Jurassic source rocks remain unpenetrated in most wells (Figures 6 and 11).
- The Elgal shale, at the Permo-Triassic boundary, is a potential source rock, being the proven source for the gas and condensate in the Calub Field in the Ogaden Basin in Ethiopia. This shale could be contemporaneous with potential reservoirs of the deeper Karoo Syn-Rift-2 and Syn-Rift-1 (Ken-3?) seismic markers and could possibly provide an easier migration route up into the shallower Ken-5 (Mansa Guda) reservoir (Figures 17-23). The mainly lacustrine, fluvial, and deltaic to swampy deposits of the early Karoo sequence may have source beds rich in either type I or type III kerogen. The late Karoo sequence likely was a restricted marine environment and may contain source beds with rich TOC.
- The Tarbaj oil seep is located immediately north of Block 2A (Figure 10), suggests the presence of an active petroleum system with oil migrating updip and being biodegraded upon contact with meteoric waters near surface. Oil may have migrated updip from the Mandera-Lugh basin depocentre; however, it remains unclear if the migration pathways would access the possibly deeper and older traps identified in Block 2A.

Reservoirs

The study area has many formations that are potential hydrocarbon reservoirs:

- The Karoo is referred to in the literature as a poorly sorted, feldspathic fluvial sandstone. The end of the Karoo time marks a significant marine incursion (E. I. Mbede and A. Dualeh).

- The Triassic-Jurassic Mansa Guda is a coarse-grained sandstone with porosity in the range of 10 to 15 percent.
- Jurassic carbonates, such as the Didimtu and Murri limestones, have wide distribution and could be potential reservoirs. Oil-filled fractures in the Murri formation have been documented from an outcrop east of Tarbaj.
- The Lower Cretaceous clastics have not been penetrated by wells in the study area but, based on data from the Ndovu-1 well that is approximately 100 km to the north, these sandstones could have porosity in the range of 10 to 16 percent.

The input reservoir parameters used in the Monte Carlo resource assessment utilizing the *Geo-X* software are shown in Figure 12.

Seals

- Cretaceous shales have the potential to act as seals.
- Upper Jurassic shales may provide seals for the Lower and Middle Jurassic reservoirs (Ken 6).
- Middle Jurassic evaporites and shales may provide effective seals within restricted basins for Karoo (Ken 5 and Ken 3) reservoirs.
- The deep Triassic and Permian reservoirs and seals remain un-penetrated in Block 2A, and there is insufficient information to predict their distribution. Conceptually, tight zones present in this interval may form seals and adequate reservoir may be a greater issue than effective seals in these older strata.
- The Permian Elgal shale may form both a good seal and source for reservoirs mapped using the deepest Syn-Rift-1 marker.

Traps and Closures

Several types of traps may be present in the study area:

- Fault-dependent traps against normal faults will be the most common trap style;
- Anticlines have been identified by seismic as possible traps;
- Stratigraphic traps formed by facies change between sand and shale are likely also present.

Preservation

While the presence of faults extending from basement up to shallower depths (Figures 21 and 23) would suggest a risk of fault seal leakage, similar late faulting occurs within successful structures in the Muglad and Melut basins in Sudan.

Risks on Chance of Discovery (Geological Chance of Success)

There is only a sparse grid of older vintage 2D seismic covering Block 2A. It has been sufficient to map three leads but these leads, and their fault-dependent closures, are constrained by only a few 2D seismic lines. Only two wells have been drilled within the block but these were drilled near the crest of a basement high and have provided limited stratigraphic information. Based upon the limited well and seismic control, new data will likely have a material effect on the resource assessment provided in this report. Given that most of the resources in the portfolio are in leads that require additional data to fully define their potential, it is likely that significant changes to the resource estimates will occur with the incorporation of additional data and information. **These resources have not yet been discovered and there is no certainty that any portion will be discovered. Even if discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.**

These leads carry very high risk because all geological risk factors are poorly defined with the limited information available at the present time. Risks were estimated and assigned to individual reservoir horizons, with resultant geological chance of success values ranging from 9 to 2 percent for single zone leads. In addition to the geological risks, there are significant uncertainties in the thickness, areal extent, porosity, hydrocarbon content and recovery factors assigned to the various exploration opportunities. These uncertainties have been accommodated in a probabilistic resource assessment, described later.

Lead 1 and Lead 2 have stacked potential at multiple horizons, and Monte Carlo simulation within the *GeoX* software was used to statistically aggregate the gross mean risked prospective resources that have been reported in Table S-2.

Risks Associated with the Estimates

There is a great deal of uncertainty in the ranges of basic reservoir parameters, such as area, porosity, net hydrocarbon pay thickness, fluid composition and water saturation. In the event of a discovery, the actual values may vary significantly from those estimated by Sproule, affecting the volume of hydrocarbon estimated to be present. Other factors, such as reservoir pressure, density, oil viscosity, and solution gas/oil ratio will affect the volume of oil that can be recovered. Additional reservoir parameters, such as permeability, the presence or absence of water drive and the specific mineralogy of the reservoir rock may affect the efficiency of the recovery process. Recovery of the resources may also be affected by well performance, reliability of production and process facilities, the availability and quality of source water for enhanced recovery processes and availability of fuel gas.

At the effective date of this report, the current seismic and well databases allow for the identification and mapping of three leads. Two of these leads have the potential to target multiple stacked pay zones. Lead 3 may test only a single zone.

The Company's ability to access the equity or debt markets in the future may be affected by any prolonged market instability. The inability to access the equity or debt markets for sufficient capital, at acceptable terms and within required time frames, could have a material adverse effect on the Company's financial condition, results of operations and prospects.

It may not always be possible for Simba Energy Inc. to execute its exploration and development strategies in the manner in which the Company considers optimal. Execution of exploration and development strategies is dependent upon the political and security climate in the host countries where the Company operates. The Company's exploration and development programs in Kenya may involve the need to obtain approvals from relevant authorities who may require conditions to be satisfied or the exercise of discretion by the relevant authorities. It may not be possible for such conditions to be satisfied.

The Company's ability to produce and market hydrocarbons from any potential discoveries will depend on its ability to access suitable infrastructure. The Company may also be affected by deliverability uncertainties related to the proximity of its potential production to pipelines and processing facilities and operational problems affecting such pipelines and facilities as well as potential government regulation relating to price and the export of oil and gas. Currently there are limited local infrastructure and markets for oil, natural gas and condensate and export infrastructure to enable other markets to be accessed has not yet been developed.

5.0 Resource Assessment

5.1 Identification of Prospectivity

In Block 2a, three spatially separate leads have been identified in independent seismic interpretation by Sproule, using the three horizons mapped in detail (Table S-2). Of these three leads, Lead 1 and Lead 2 have multiple target zones with closure at all stratigraphic levels. Lead 3 is defined only at the shallowest Ken 5 stratigraphic level.

Lead 1

Three 2D seismic profiles define the structural form of Lead 1. Despite the poor reflection continuity at depth, 2D seismic line VTU01 (Figure 17) shows a downthrown horst block to the ENE of the major light green fault. Closure at the Ken 5 and Syn-Rift-2 levels would be fault-dependent against the major light green fault. There is a thick stratigraphic wedge developed at the Syn-Rift-1 and deeper levels that may provide more secure closure in this deep antiformal horst.

Relatively short line VTU03 (Figure 18) again shows fault-dependent closure against the major light green fault at the shallower Ken 5 and Syn-Rift-2 levels. At the Syn-Rift-1 and Basement seismic markers, an attractive rollover feature is well developed in front of the major fault.

The longer 2D seismic line KT742 (Figure 19) passes along the southeast flank of Lead 1 and shows the interpreted continuation of the horst observed in Figure 19.

Lead 2

Southwest-northeast trending 2D seismic profile 747 passes directly over the crest of Lead 2. A highside fault-dependent closure has been mapped at all stratigraphic levels from Ken 5 to Basement (Figure 20). The antiformal shape of lead 2 is evident on 2D line KT749 which cuts northwest-southeast across the northern flank of this prospect (Figure 21). Additional 2D seismic would be required to refine the structural form of this prospect which is crossed only by the above two seismic profiles.

Lead 3

The 2D seismic line KT749 also traverses the northeast flank of Lead 3 which is a down-thrown fault block adjacent to a major pale green fault (Figure 21).

Line KT748 is a strike line along the crest of Lead 3 (Figure 23). Although poor in reflection continuity at depth, this 2D seismic profile does support the presence of a prominent anticlinal shape structure which plunges both to the southwest and northeast. The deeper Ken 5 to Basement section has dramatically thinned. There is a risk of leakage across a spillpoint to the west, and futher seismic is required to more accurately define the closure area.

5.2 Prospective Resources

No reserves or contingent resources have been assigned to Block 2A.

Prospective resources have been estimated for the three undrilled leads based on closures identified in the independent seismic interpretation. Based on the regional geological settings and well log data, Permian, Triassic and possibly Jurassic sediments in the Mandera-Lugh basin have been considered prospective. Time structure maps on six horizons have been generated (Figures 24-28). Figures 25-27 show the P05 and P90 (5 percent and 90 percent probability) closure areas chosen for the three leads on the Ken 5, Syn-Rift-2, and Syn-Rift-1 horizons.

The structural leads can be classified into two main categories:

- Four-way closure structural traps,
- Fault-dependent traps.

The Block 2A leads have been assessed using probabilistic models developed in *GeoX*. The ranges of input parameters are summarized in Figure 12. Input distributions for area were developed from the seismic time interpretation, and from well log analysis for gross reservoir thickness, net-to-gross ratio, porosity and water saturation from other wells within the area (Figure 11). These wells have not penetrated these deeper reservoir targets and the reservoir properties have been estimated from these shallower zones. Recovery factors were estimated using a lognormal distribution with a range of 10 to 40 percent.

As noted previously, these leads carry very high risk because all geological risk factors—reservoir, source, seal, trap, migration, timing and preservation—are poorly defined with the limited information available at the present time. In addition, there is insufficient information available to ascertain whether the predominant hydrocarbon type will be natural gas or oil; as a result, the resources have been identified simply as "petroleum" and reported as barrels of oil equivalent (BOE).

The total gross unrisked undiscovered petroleum initially in-place is estimated to range from 41.5 to 615.8 MMboe with a mean of 272.1 MMboe, and the total gross unrisked recoverable prospective resources are estimated to range from 7.32 to 146.4 MMboe with a mean of 62.9 MMboe, as detailed in Table S-2.

Risks were assigned to individual horizons. Leads 1 and 2 have stacked potential at multiple horizons as shown in Table S-2. The results from individual stacked leads have been aggregated statistically to provide risked mean prospective resources shown in the last column of Table S-2. **These resources have not yet been discovered, and there is no certainty that any portion will be discovered. Even if discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.**

Only the Elgal-1 and Elgal-2 wells have been drilled in Block 2A, and potential reservoir parameters for these deeper reservoir targets are unknown. Two-dimensional seismic is sufficient to identify the three leads, but additional data would no doubt modify the shape of the structural closures. The exploration results in surrounding countries (e.g., Ethiopia) and the presence of the Tarbaj oil seep at the subcrop edge of the southern structural nose confirm that an active petroleum system could exist. Given the current unknowns and uncertainties, resource estimates have been made for Block 2A, and it is Sproule's opinion that this block has potential that justifies further exploration.

6.0 Exploration Work Program

The Company's exploration plans for Block 2A include the following:

- GeoDynamics S.R.L. of Italy has been contracted to conduct an Infrasonic Passive Differential Spectroscopy (IPDS) seismic survey covering 4000 km^2 with 250 measurement points on a variable spacing beginning mid-June 2012;
- The potential areas identified by the passive micro-seismic survey will be further evaluated by conventional seismic, most likely 3D or 2D and/or gravity gradiometer prior to selecting a drill site;
- An additional 1000 kilometres of 2D and/or equivalent 3D seismic data and/or equivalent passive seismic is planned for Block 2A;
- Based upon the results of the 2D seismic program, a drilling program to evaluate the leads will be designed.

6.1 Estimated Exploration Costs

- Infrasonic Passive Differential Spectroscopy (IPDS) – The program planned for June 2012 is estimated to cost $US 1,200,000 including survey and interpretation
- The geochemical survey done at the same time is expected to be $US 100,000
- The seismic program are dependent on what type of seismic is required 2D and/or equivalent 3D seismic data and/or equivalent Passive seismic. The equivalent is based on cost of each type. The total cost based on 1000 kilometres (500 km in each of the initial 2 year periods) of 2D base is $US 10,000,000 to 12,000,000
- An exploratory well to 3000m is expected to cost $US 7,000,000 to 10,000,000

Sproule has reviewed the technical data and the Company's exploration plans related to these holdings, and it is our opinion that

- The holdings are prospective and justify the Company's plans to further delineate them with additional passive micro-seismic, 2D or 3D seismic and gravity gradiometers surveys;
- The proposed program constitutes a reasonable and prudent approach to the exploration and possible future development of these lands.

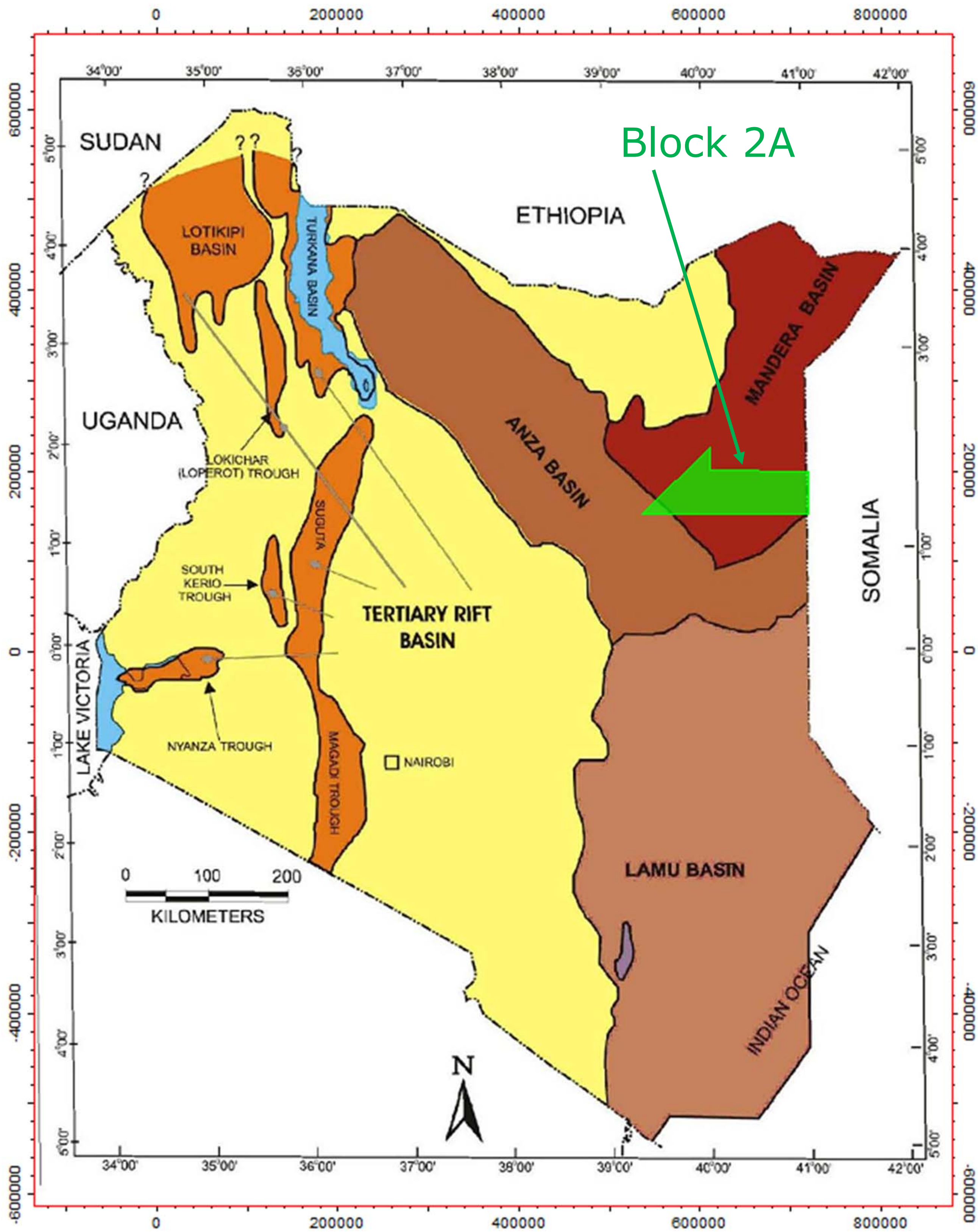
In reviewing the properties, we have taken into account all known available pertinent factors, such as geological structures, prospective producing zones, historical exploration and development activity, terrain, accessibility, access to infrastructure and markets, operating status of the lands, acquisition costs and anticipated program costs.

No gas or oil infrastructure exists in the area. The nearest production and infrastructure is located in Sudan. Another option would be to build an oil pipeline to Lamu, on the Kenyan coast, approximately 400 km south of Block 2A. If built, the necessary refining and/or processing and export facilities would also have to be built in Lamu.

7.0 Summary

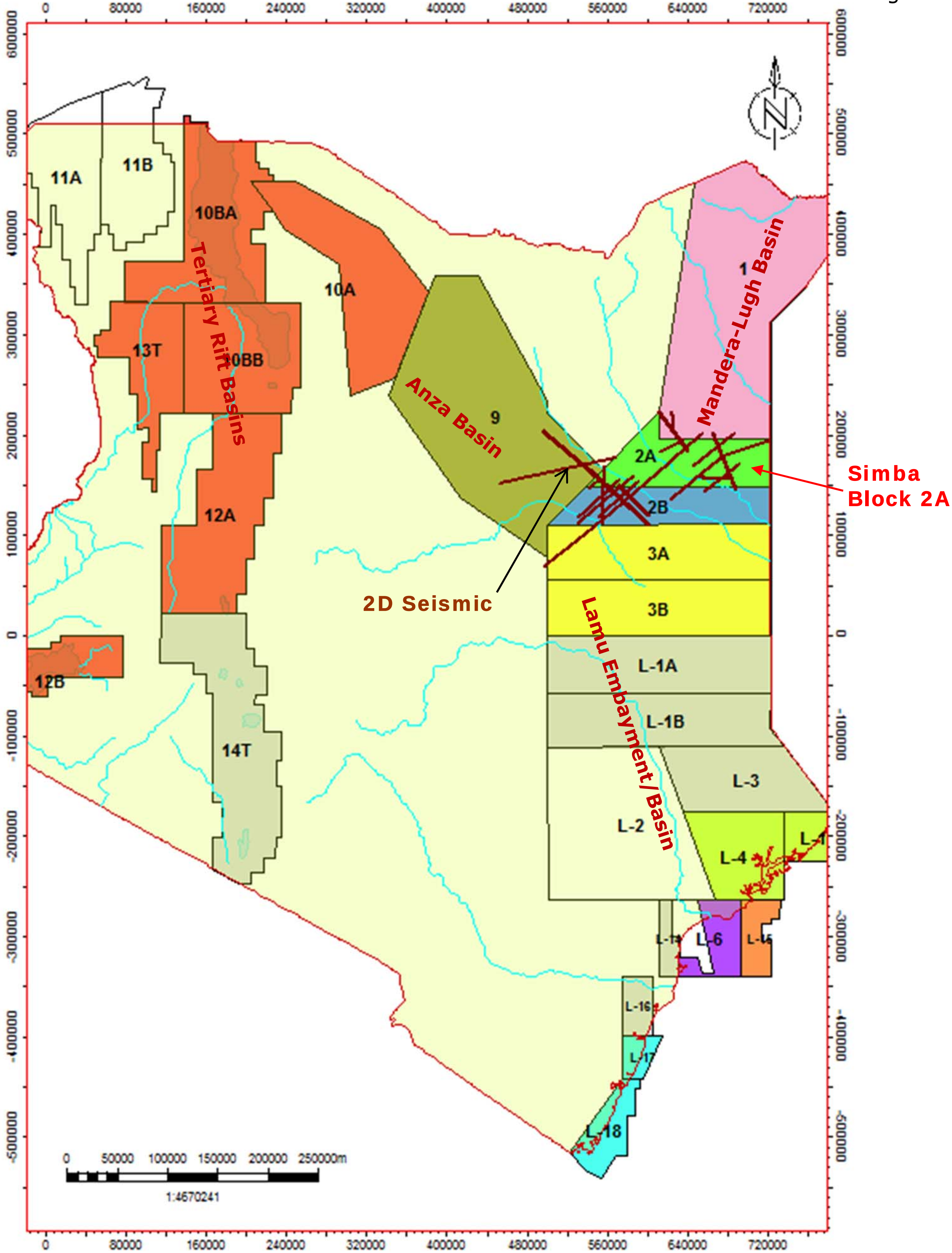
In summary, it is Sproule's opinion that

- The Company's holdings are prospective for oil or natural gas and warrant further exploration;
- The Company's proposed work program is a prudent and reasonable approach to the exploration and possible future development of these holdings;
- The Company's estimated costs for the proposed work program are believed to be reasonable.



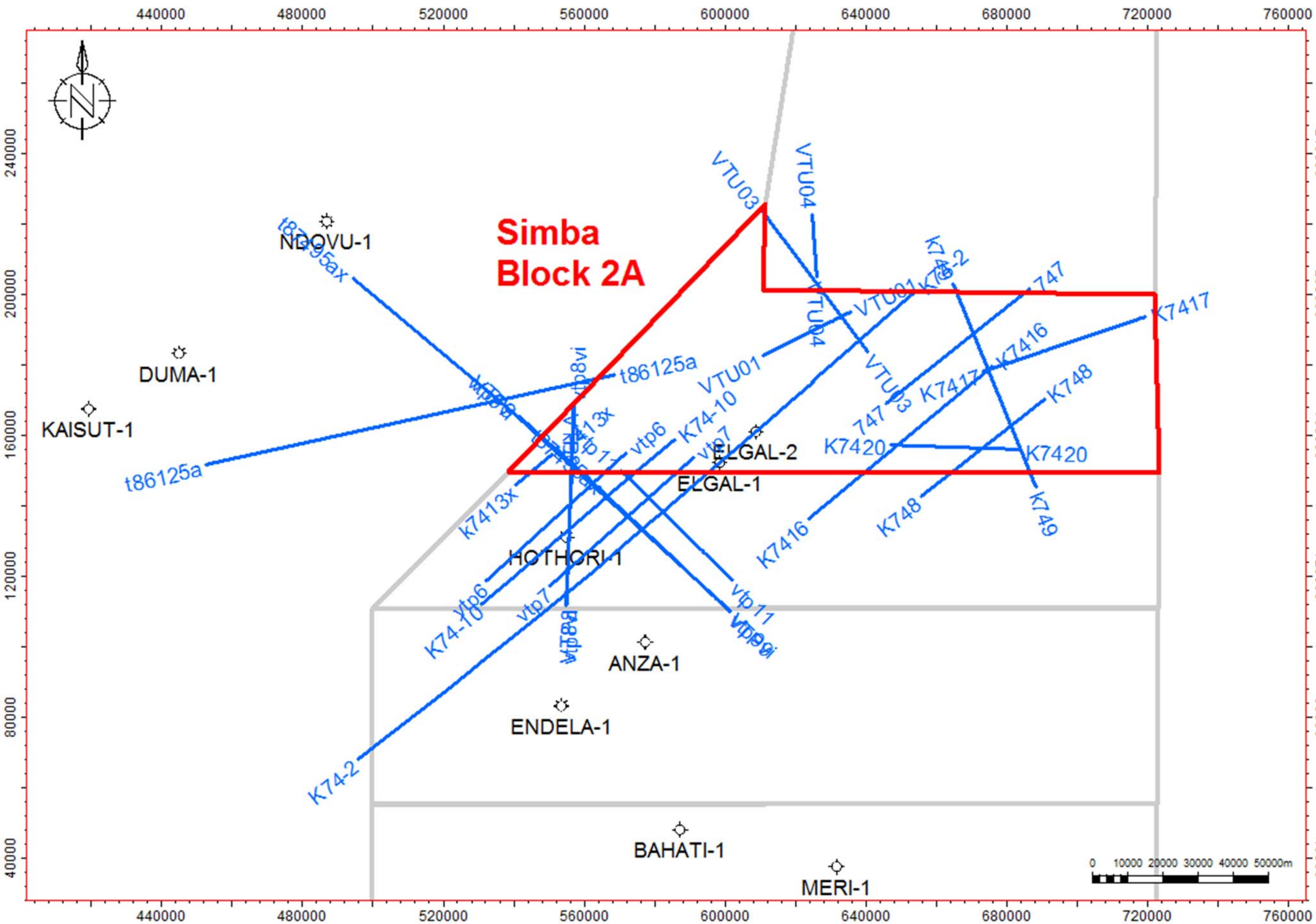
Source: National Oil Corporation of Kenya, 2010

Kenya Geological Basins



Source: modified from Simba Energy Inc. website

Exploration Permits in Kenya



Block 2A Seismic and Well Control

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Figure 3

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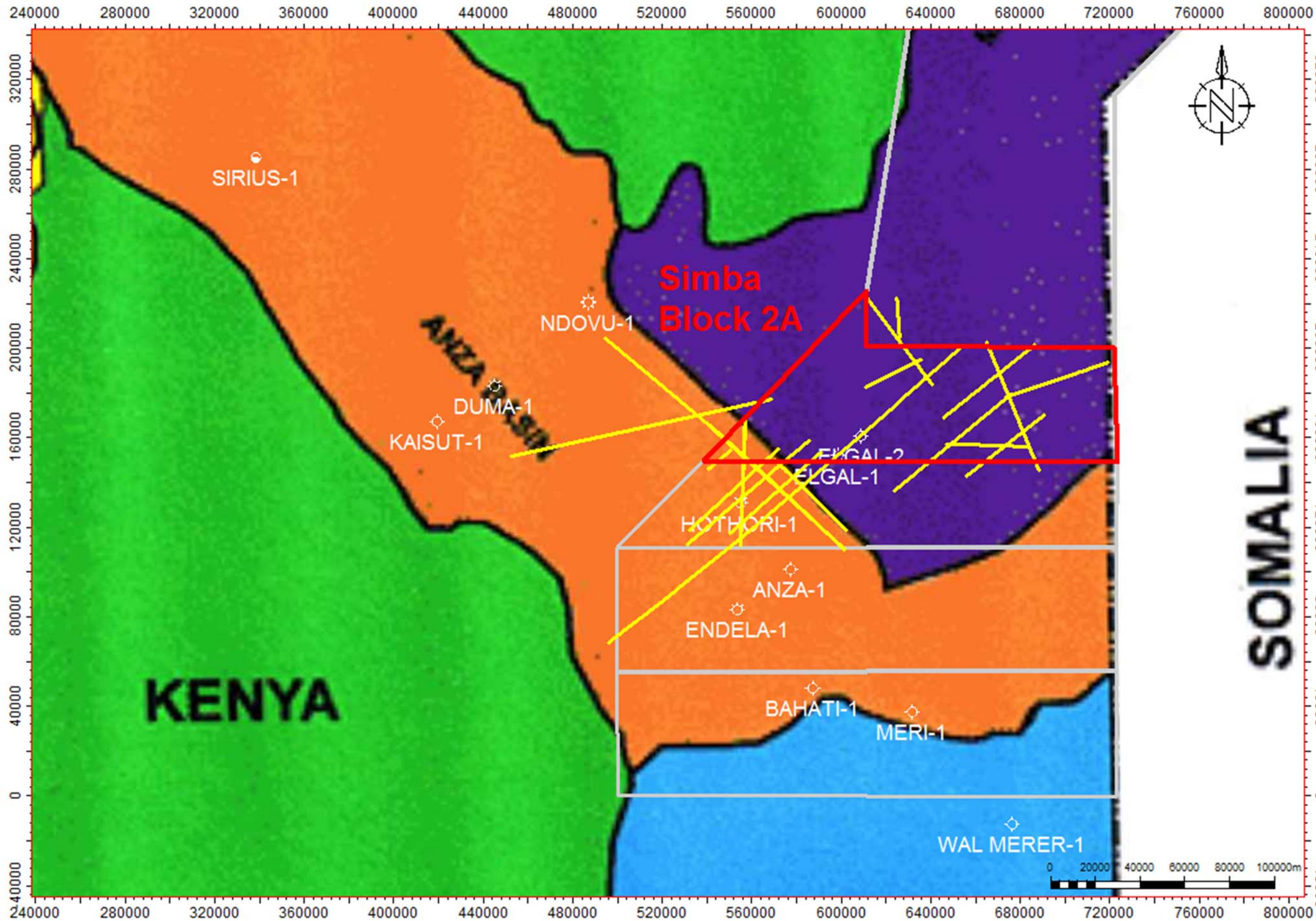

Block 2A Seismic in Relation to Basin Outlines

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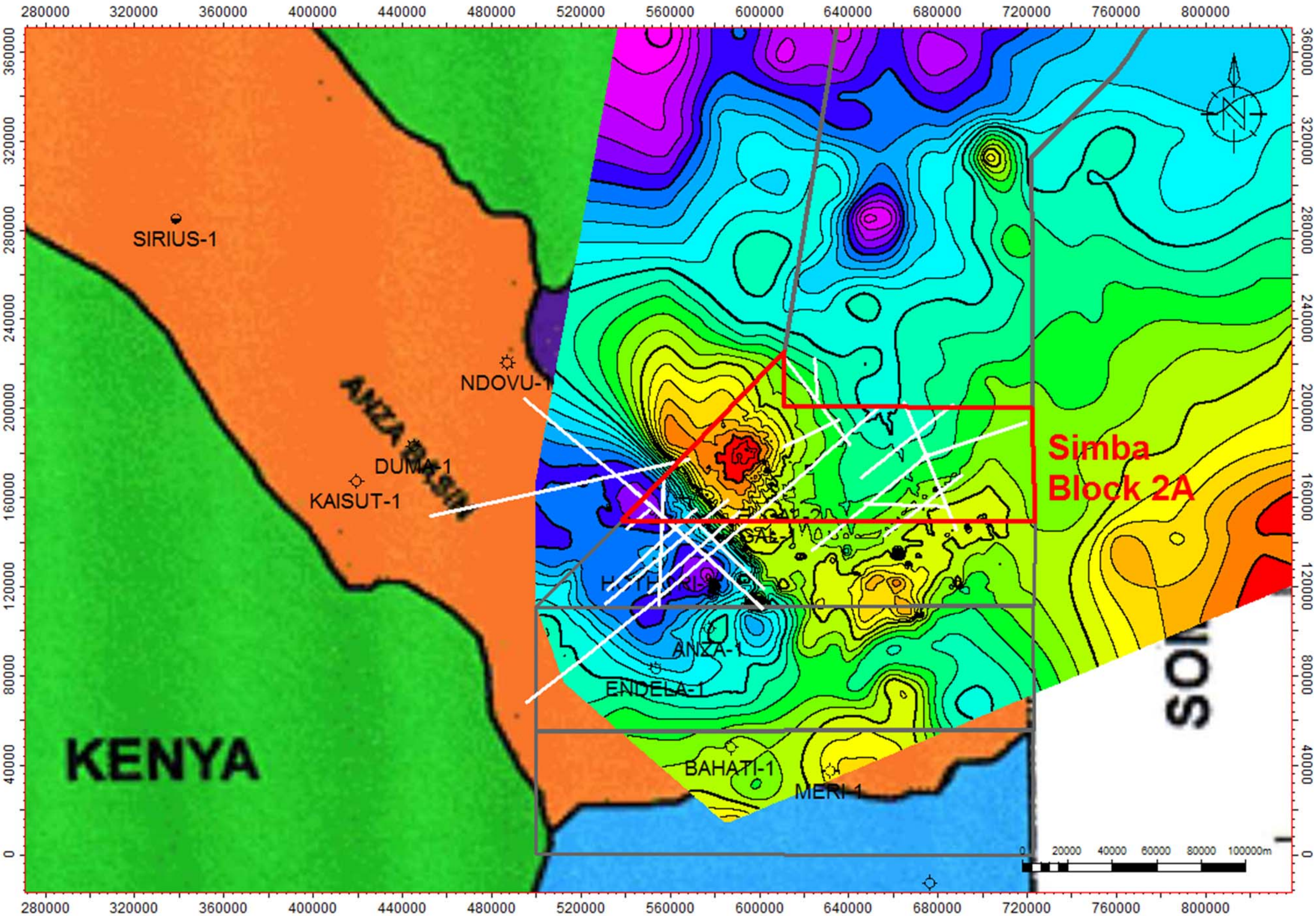
Figure 4



Bouguer Gravity Overlain Upon Regional Basin Trends

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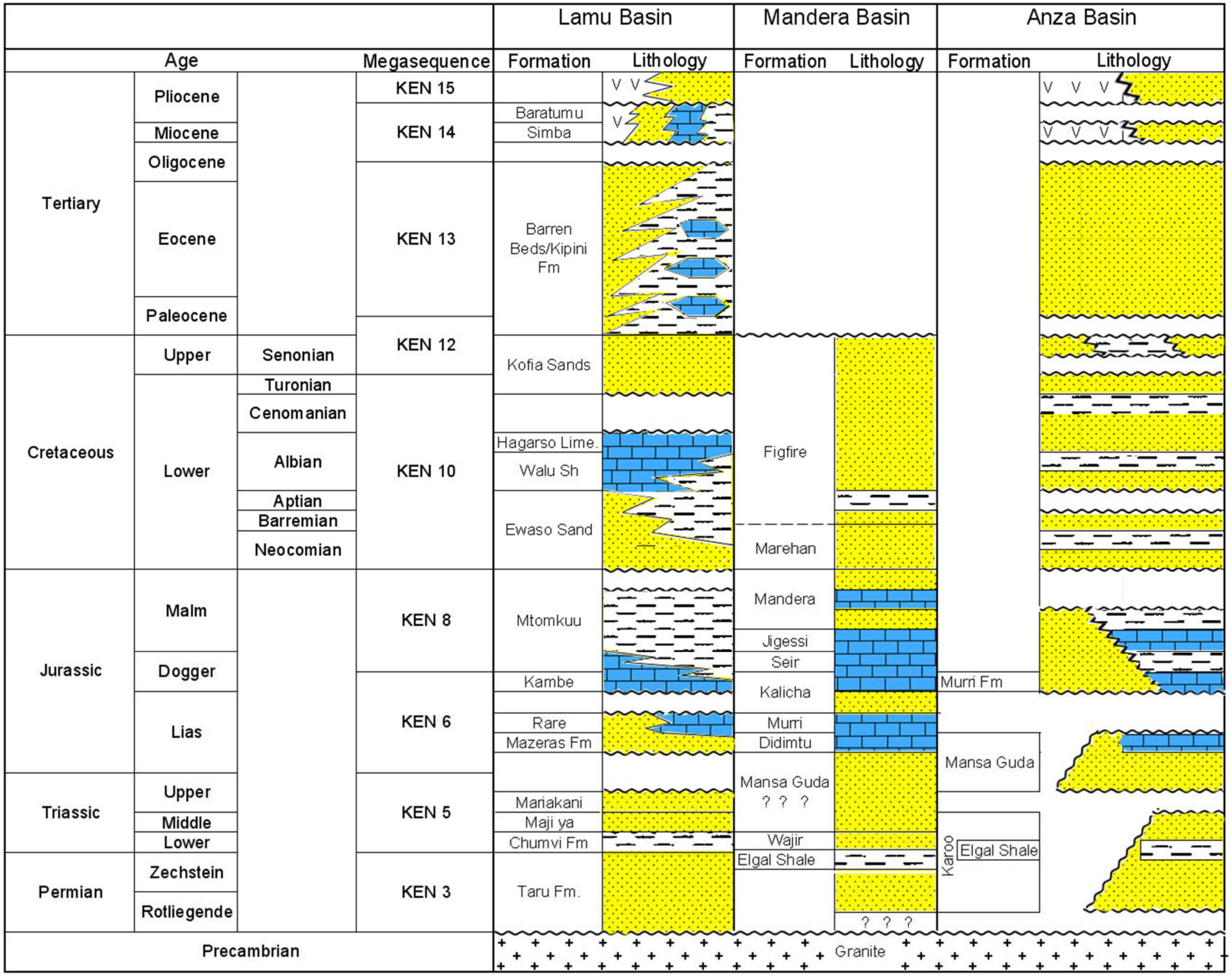
Figure 5



Source: Kerr, MacKeith, Nyagh and Ngenoh (1997)

Generalized Stratigraphic Table

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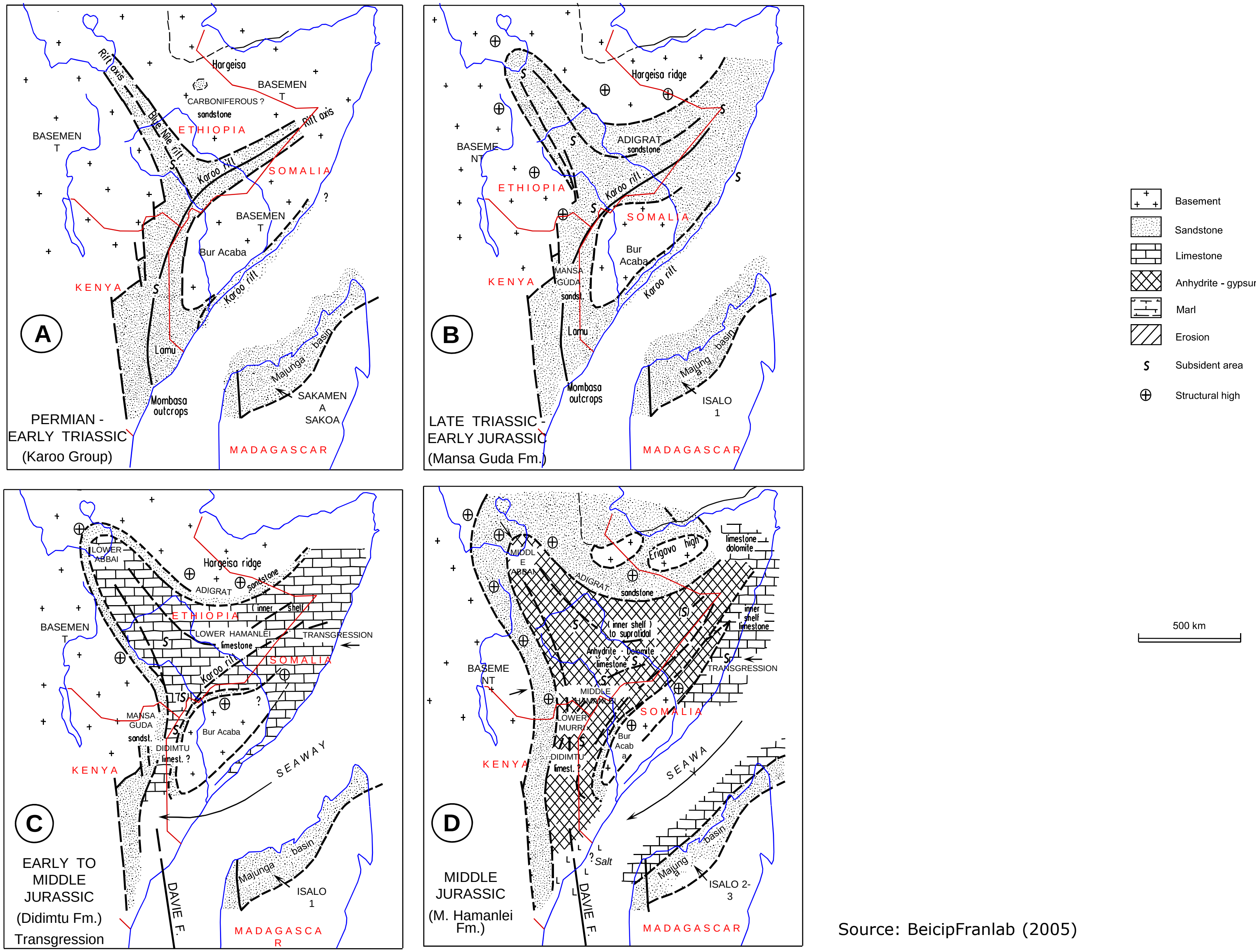
Figure 6



Source: BeicipFranlab (2005)

Maps Showing Paleogeography and Tectonic History (Continued on Figure 8)

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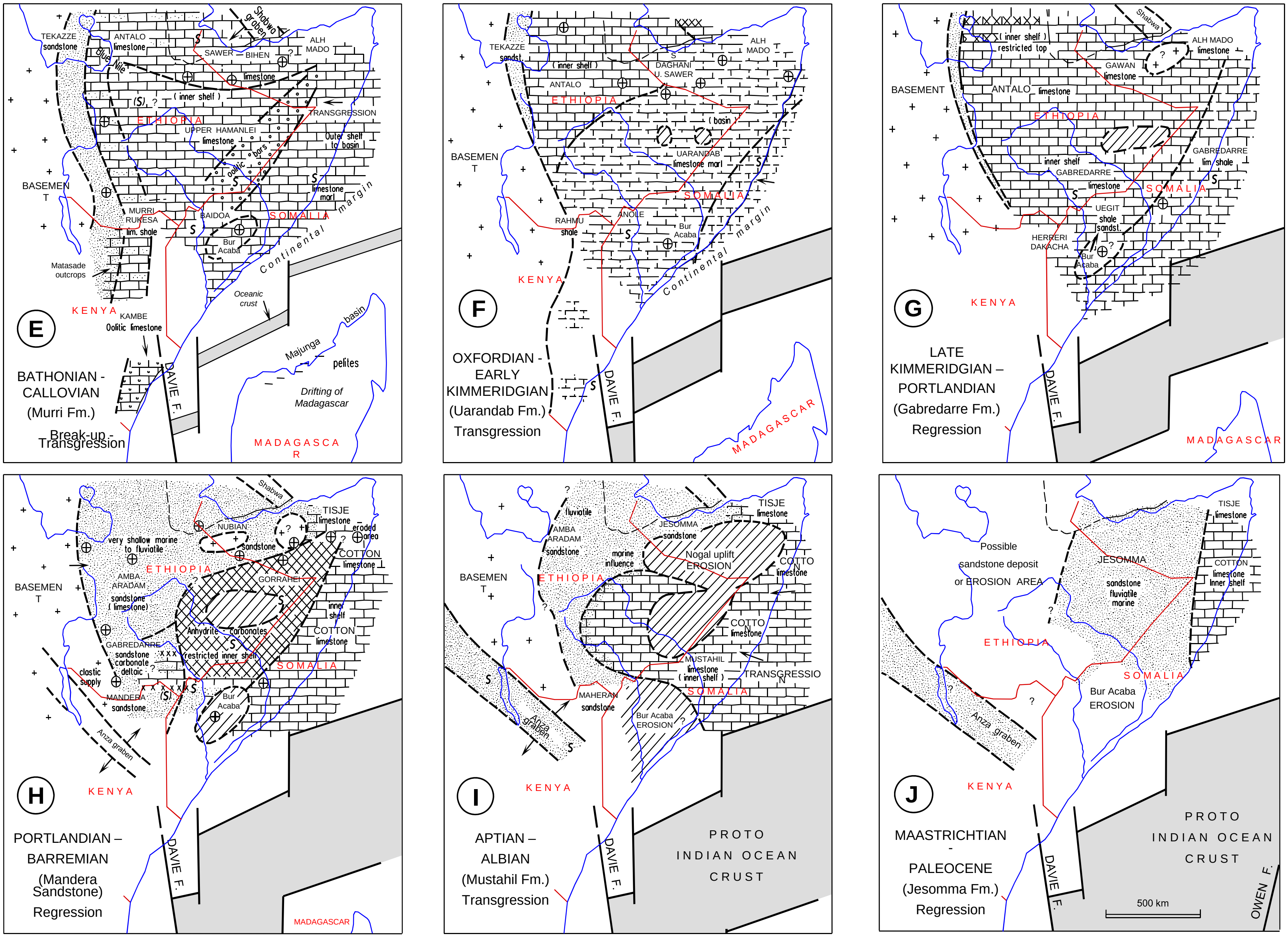
Figure 7



Maps Showing Paleogeography and Tectonic History (Continued from Figure 7)

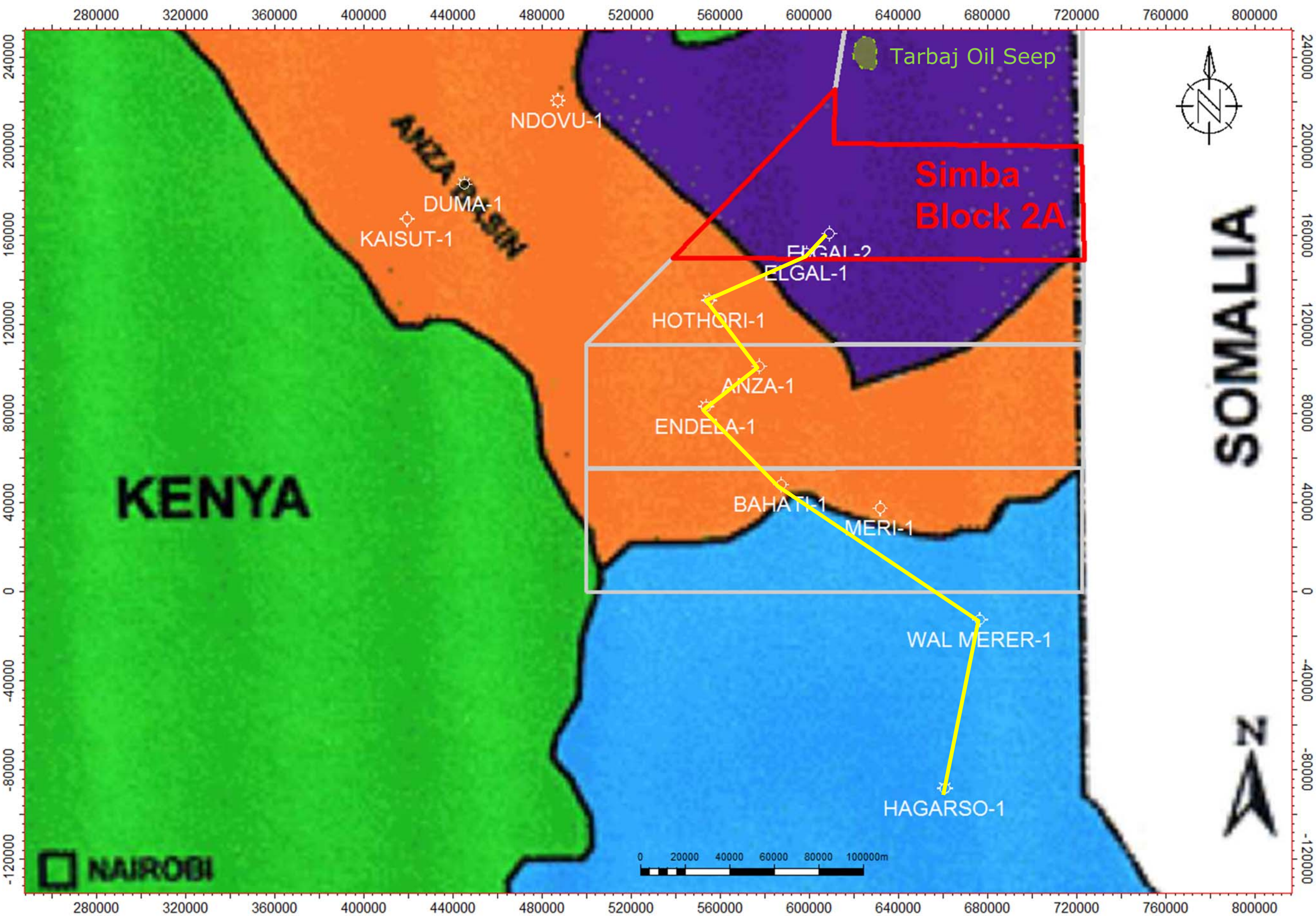
Figure 8

Sproule

BLOCK #	WELL	OPERATOR	LOCATION		TOTAL DEPTH	STATIGRAPHIC LEVEL AT TOTAL DEPTH		YEAR COMPLETED	STATUS
			LAT (S/N)	LONG (E)	(M)				
L-3	WALU - 1	BP/ SHELL	01°38'04"S	40°15'09"E	1,768	LATE CRET	SENONIAN	1960	P&A
L-4	PANDANGUA -1	BP/ SHELL	02°05'51"S	40°25'15"E	1,982	EARLY TERT.	PALEOGENE	1960	P&A with gas show in tertiary
3	MERI	BP/ SHELL	0°20'36"N	40°11' 00"E	1,941	EARLY TERT.	PALEOGENE	1961	P& A
L- 3	MARARANI	BP/ SHELL	01°34'57"S	41°14'10"E	1,991	EARLY TERT.	PALEOGENE	1962	P&A with fluorescence in tertiary
7	RIA KALUI	MEHTA & CO.			1,538	PERMO-TRIAS	KAROO	1962	P & A with oil stain in Permo-Trias Karoo?
L- 3	WALU - 2	BP/ SHELL	01° 38'02"S	40°15'10"E	3,729	EARLY CRET.	APTIAN	1963	P&A with fluorescence in cret.
L - 5	DODORI	BP/ SHELL	01°48'53.7"S	44°11'04"E	4,311	LATE CRET	CAMPANIAN	1964	P&A with oil-gas shows in Tertiary/Cret
L -3	WAL MERER	BP/ SHELL	0°05'35"S	45°35'05"E	3,794	EARLY CRET.	NEOCOMIAN	1967	P&A with gas shows in Cret.
L - 1	GARISSA	BP/ SHELL	0°22'04"S	39°48'43"E	1,240	MID JURRASSIC	BATHONIAN	1968	P&A
L - 5	PATE	BP/ SHELL	02°03'53.98"S	41°04'52"E	4,188	EARLY TERT.	EOCENE	1971	P&A with gas shows in Eocene
L - 6	KIPINI	BP/ SHELL	02°29'23.57"S	40°35'51"E	3,663	LATE CRET	CAMPANIAN	1971	P&A with flour. & gas shows in Tert. / Cret.
L - 1	HAGARSO	TEXAS PACIF.	0° 47'43.5"S	40°26'40.5"E	3,092	EARLY CRET.	ALBIAN	1975	P&A with gas shows in Cret.
3	ANZA	CHEVRON	0°55'10.864"N	39°41'42.761"E	3,662	LATE CRET	CENOMANIAN?	1976	P & A with oil stain in Cretaceous
3	BAHATI	CHEVRON	0°26'32.913"N	39°47'5.077"E	3,421	LATE CRET	CENOMANIAN?	1976	P & A with oil stain in Cretaceous
L - 9	SIMBA (offshore)	TOTAL	04°00'06.60"S	40°34'03.68"E	3,604	LATE CRET	CAMPANIAN	1978	P&A with gas shows in Tert./ Cret
L - 6	MARIDADI 1 - B (offshore)	CITIES	2°53'8.795"S	40°24'7.856"E	4,198	MID TERT.	OLIGOCENE	1982	P &A with gas shows in Tertiary
L - 7	KOFIA (offshore)	UNION	02°32'31.90"S	40°56'18.30"E	3,629	LATE CRET	MAASTRICHTIAN	1985	P &A with flour. And gas shows in Tert./ Cret
L - 1	KENCAN	PETRO-CANADA	0°18'57.384"S	39°46'16.572"E	3,863	PERMO-TRIAS	KARROO	1986	P & A
2	ELGAL - 1	AMOCO	01°22'47"N	39°53'09"E	1,280	PERMIAN	KARROO	1987	P & A with (Stratigraphic well)
2	ELGAL - 2	AMOCO	01°27'32.708N	39°58'40.063"E	1,908	TRIASSIC	KARROO	1987	P & A with (Stratigraphic well)
9	NDOVU	TOTAL	01°59'58"N	38°52'57"E	4,269	EARLY CRET.	HAUTERIVIAN	1988	P &A with flour. & gas shows in Cret
10	SIRIUS	AMOCO	2°35'00.14"N	37°32'48.98E	2,638			1988	P & A
10	BELLATRIX	AMOCO	2°42'12.98"N	37°32'22.34"E	3,480			1988	P & A
9	DUMA	TOTAL	1°39'35.66"N	39°30'19.77"E	3,333	EARLY CRET.	APTIAN?	1989	P & A with gas shows in Cret
2	HOTHORI	AMOCO	01°11'16.8"N	39°29'37.8"E	4,392	LATE CRET		1989	P & A with flour. & gas shows in Tert./ Cret.
10	CHALBI - 3	AMOCO	3°01'50.81"N	37°24'43.09"E	3,644			1989	P & A
3	ENDELA	WALTER	0°45'20"N	39°28'52"E	2,779	EARLY TERT.	PALEOGENE	1989	P & A with gas shows in Paleogene
9	KAISUT	TOTAL	1°31'03.82"N	38°16'28.89"E	1,450	EARLY TERT.	PALEOGENE	1989	P & A
10B	LOPEROT - 1	SHELL	02°21'46.229"N	35°52'24.132"E	2,950	PALEOCENCE?		1992	P & A with oil shows
10B	ELIYE SPRINGS - 1	SHELL	03°13'50.62"N	35°54'40.19"E	2,964	UPPER MIOCENE?		1992	P & A

Source: National Oil Corporation of Kenya, http://www.nockenya.co.ke/pdf/deep_wells_drilled.pdf

Historical Summary of Deep Wells Drilled in Kenya

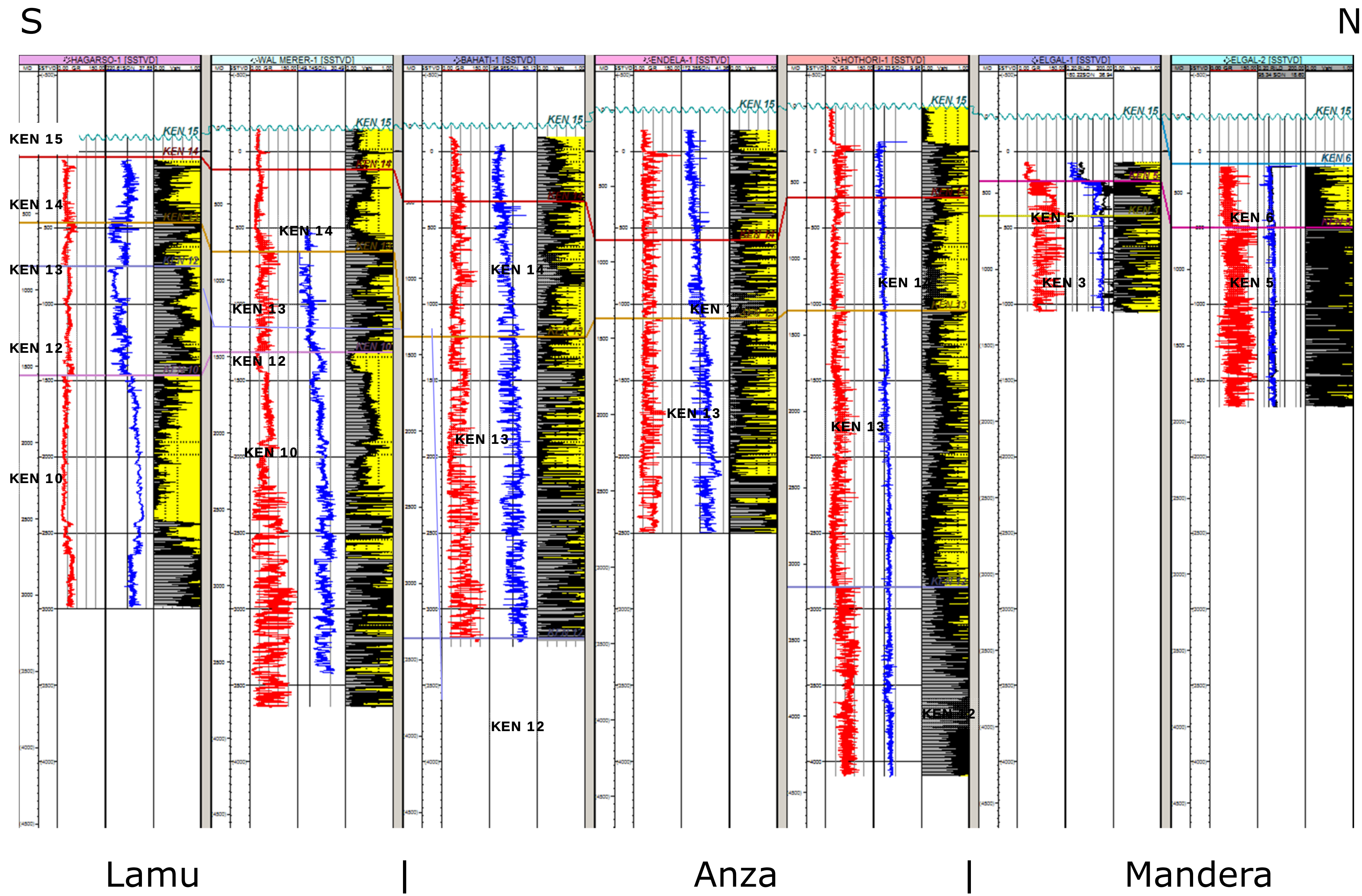


Line of S-N Cross-Section Through Lamu-Anza-Mandera Basin Wells

70693

Sproule

Figure 10



S-N Cross-Section Through Lamu-Anza-Mandera Basin Wells

Figure 11

Sproule

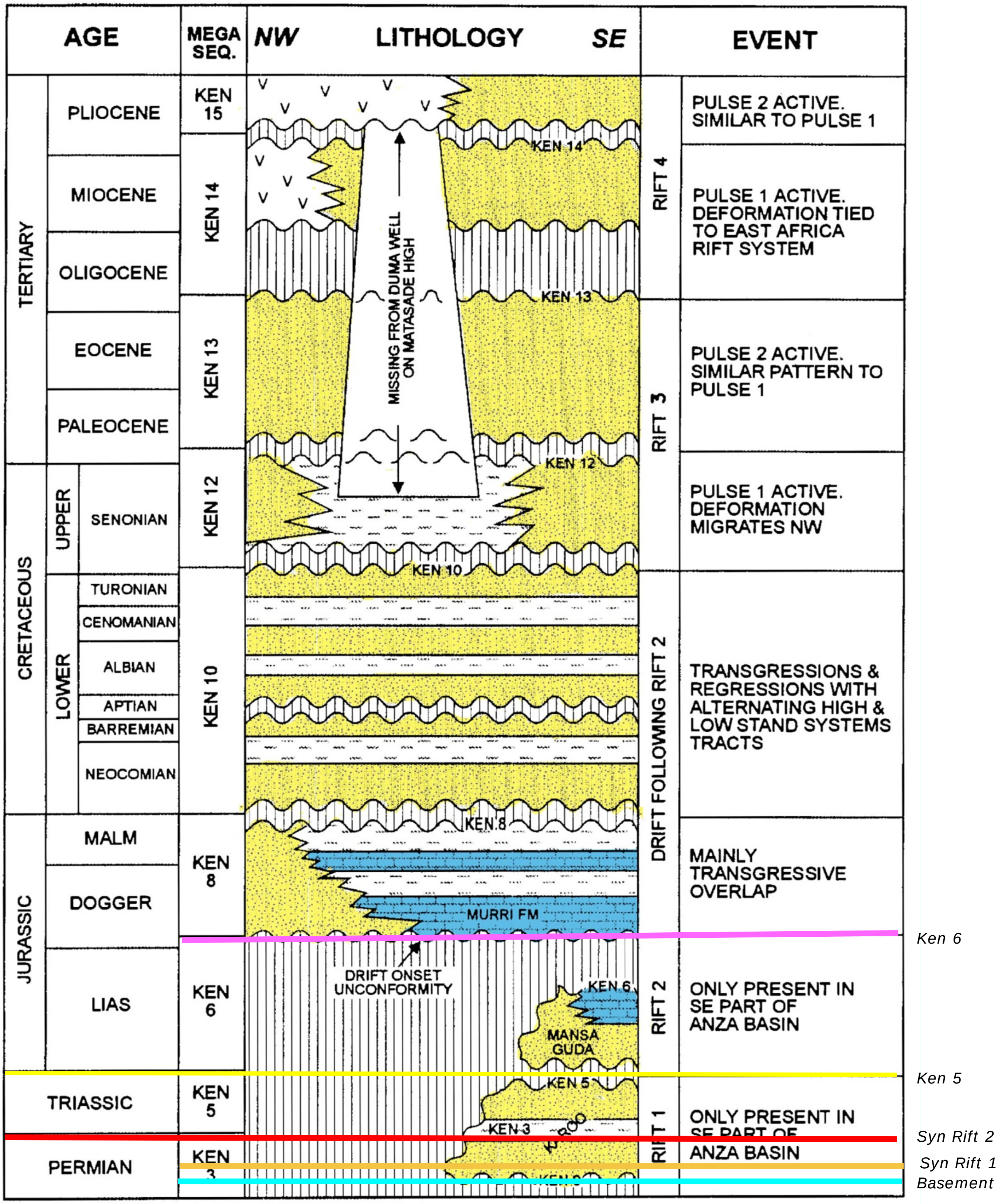
Simba Energy Inc

Input Volumetric Parameters for Probabilistic Assessment

	Surface	Prospect / Lead	Area (km^2)			Net Pay (m)			Porosity (%)			Saturation (%)			Bo		
			P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10	P90	P50	P10
Block 2A	Ken 5	Lead 1	14	39	109	10	26.5	70	7	9.5	12	40	55	70	1.1	1.2	1.3
		Lead 2	5	14	39	10	26.5	70	7	9.5	12	40	55	70	1.1	1.2	1.3
		Lead 3	10	23	54	10	26.5	70	7	9.5	12	40	55	70	1.1	1.2	1.3
	Syn Rift 2	Lead 1	11	31	90	5	15.8	50	5	8.5	12	40	55	70	1.1	1.2	1.3
		Lead 2	6	17	62	5	15.8	50	5	8.5	12	40	55	70	1.1	1.2	1.3
	Syn Rift 1	Lead 1	14	41	120	5	15.8	50	5	8.5	12	40	55	70	1.1	1.2	1.3
		Lead 2	10	16.1	26	5	15.8	50	5	8.5	12	40	55	70	1.1	1.2	1.3

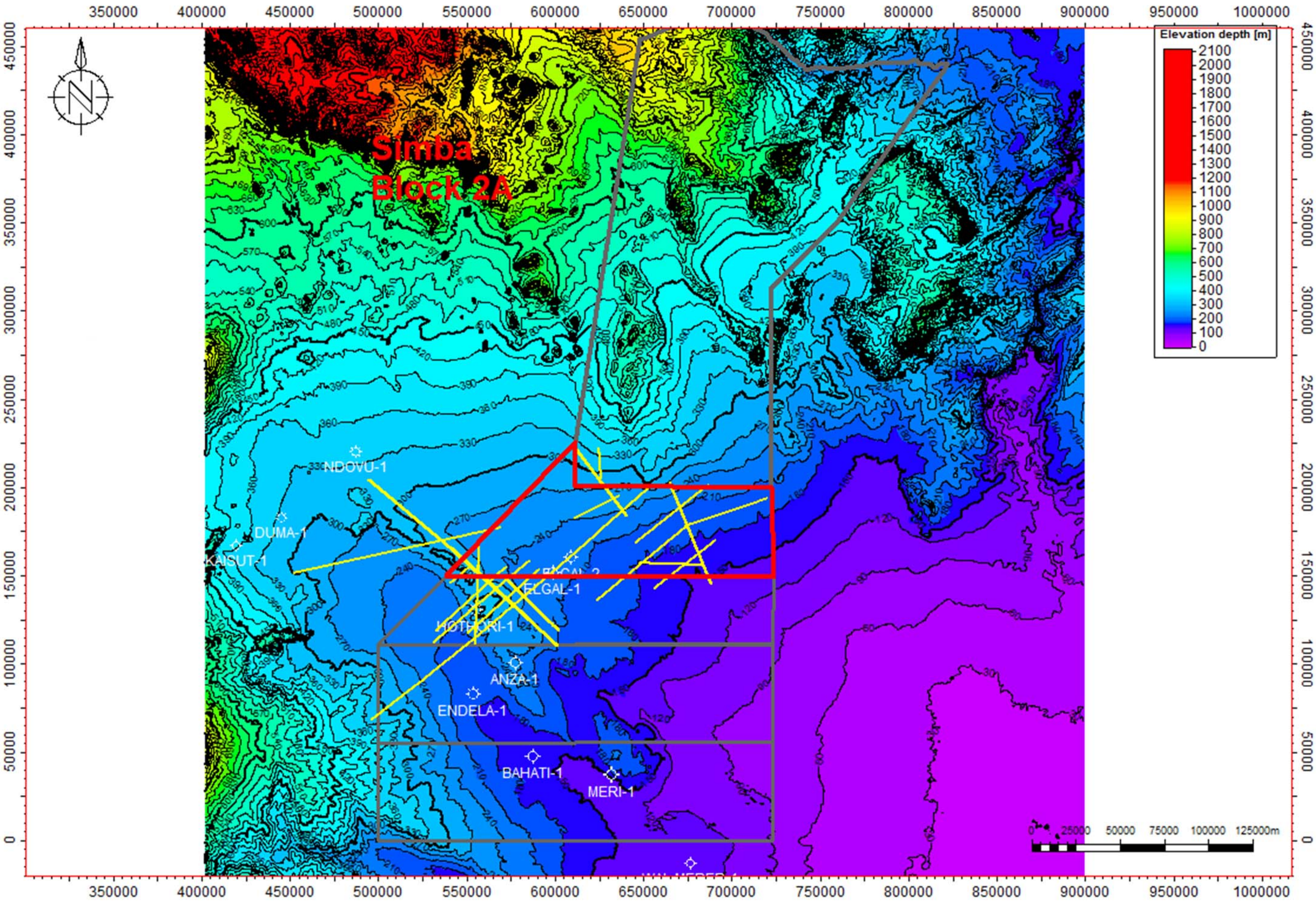
- Ken 6 — Lower Jurassic Liassic (Kalicha-Murri-Didimtu)
- Ken 5 — Triassic [Mansa Guda reservoirs (Mariakani / Maji ya Formations?)]
- Syn-Rift 2 — unpenetrated locally, age uncertain; Permian Zechstein/Rotliegende?; Wajir/Karoo Formation?
- Syn-Rift 1 — unpenetrated locally, age uncertain; early Permian Rotliegende?; Karoo Formation?
- Basement

Input Volumetric Reservoir Parameters



Source: Danson Mburu (2012)

Generalized Regional Stratigraphy



Digital Elevation Model (DEM), Seismic & Well Control, Block Boundaries

Figure 14

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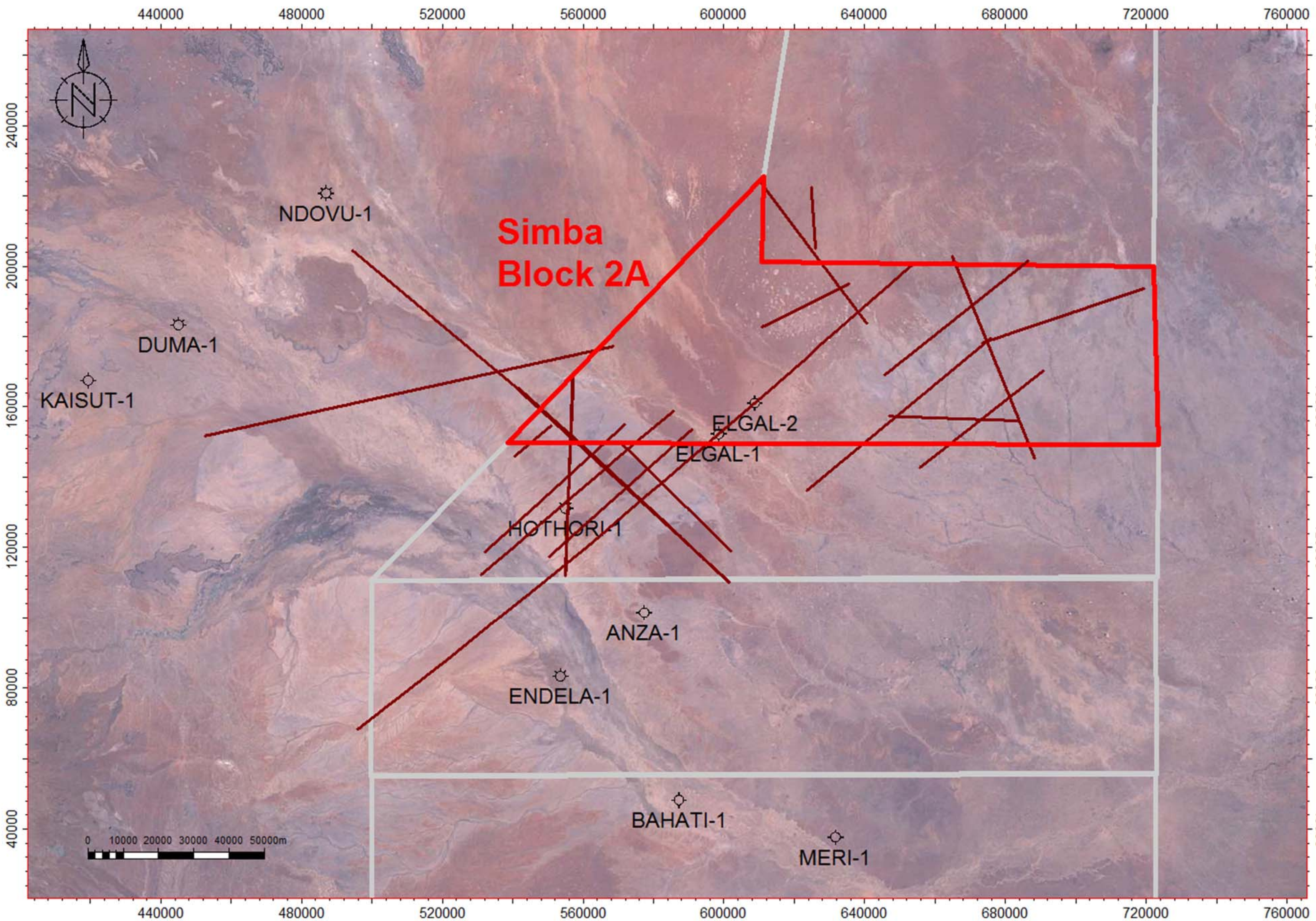
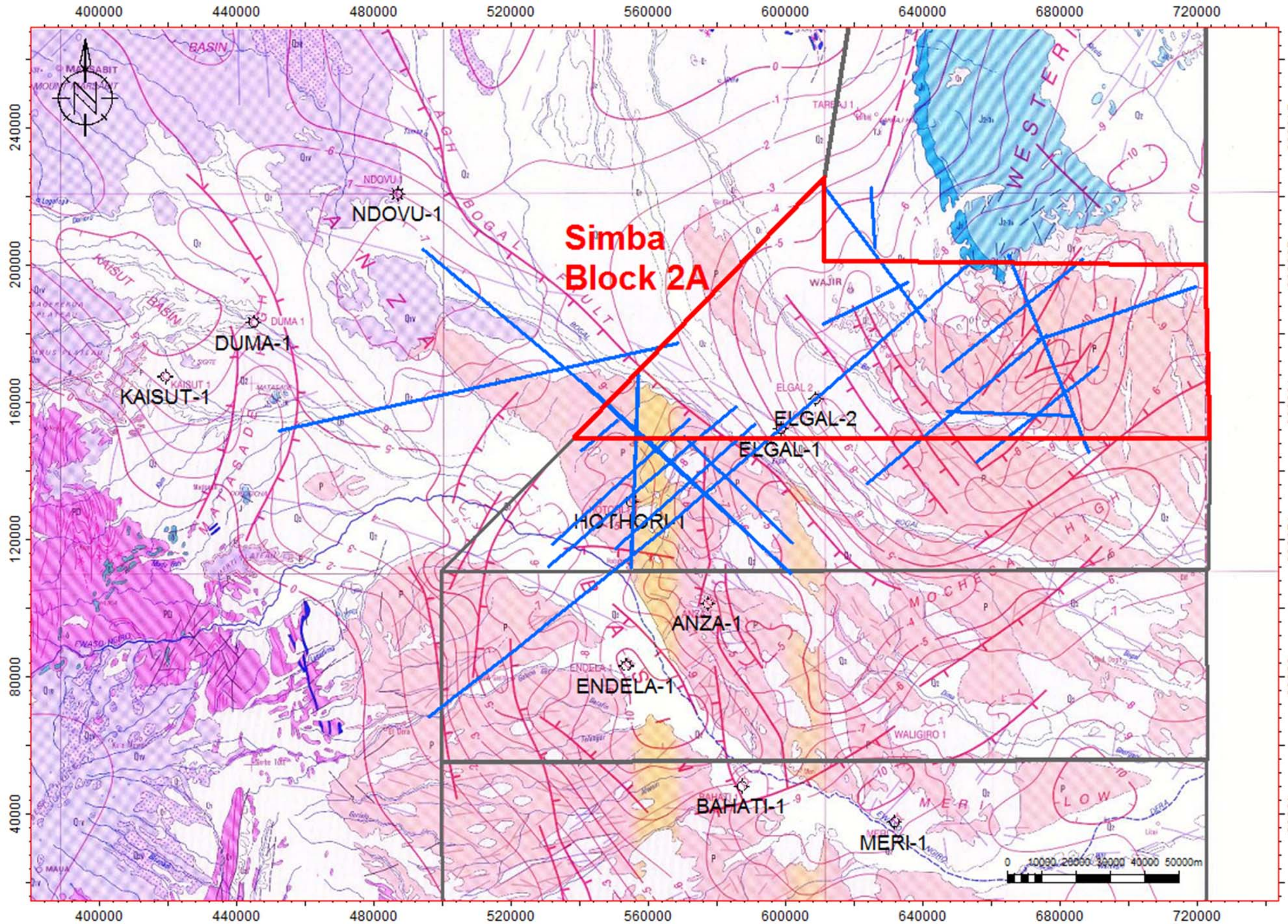


Landsat, Seismic & Well Control, Block Boundaries

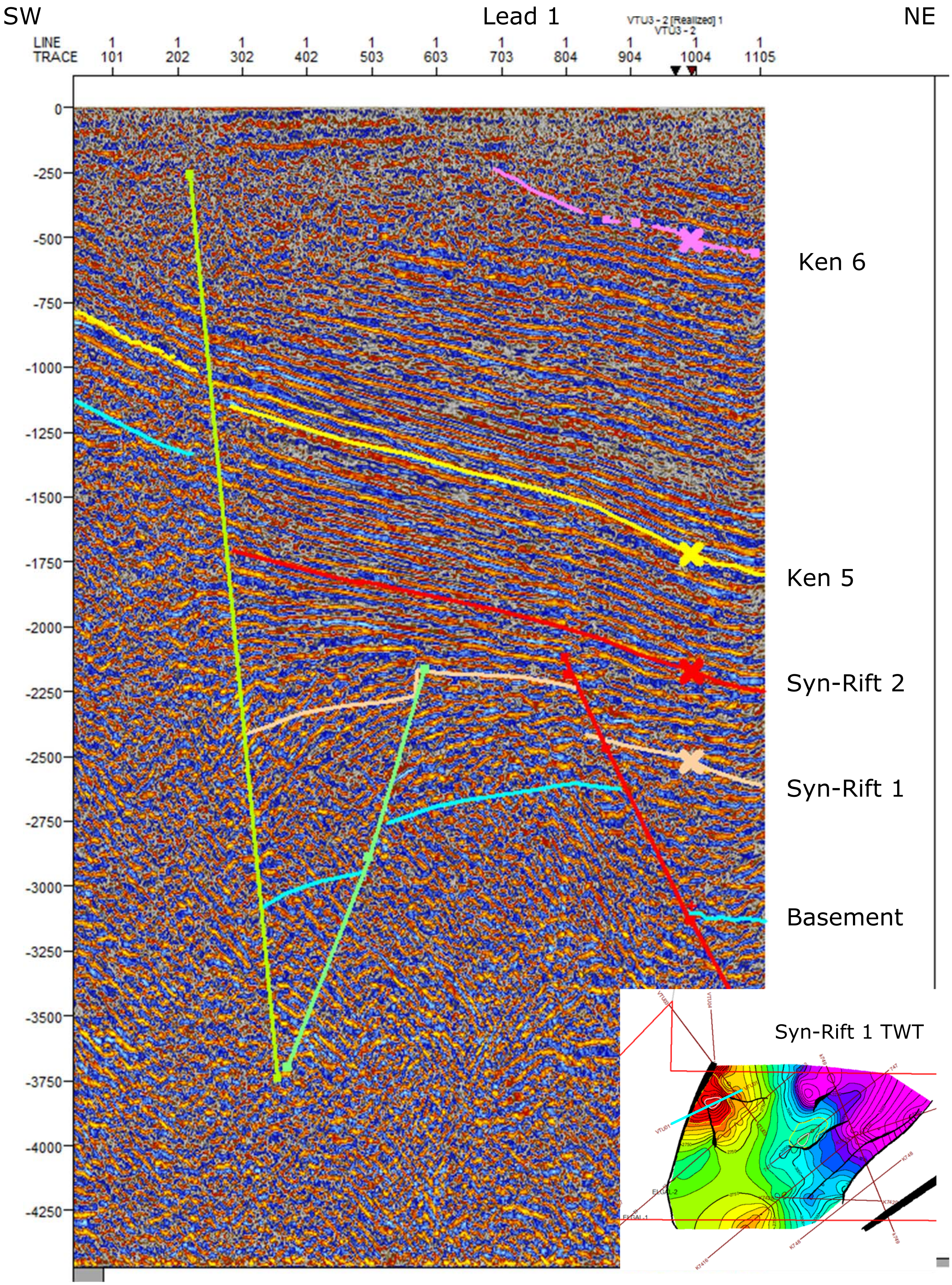


Source: Kenyan Government

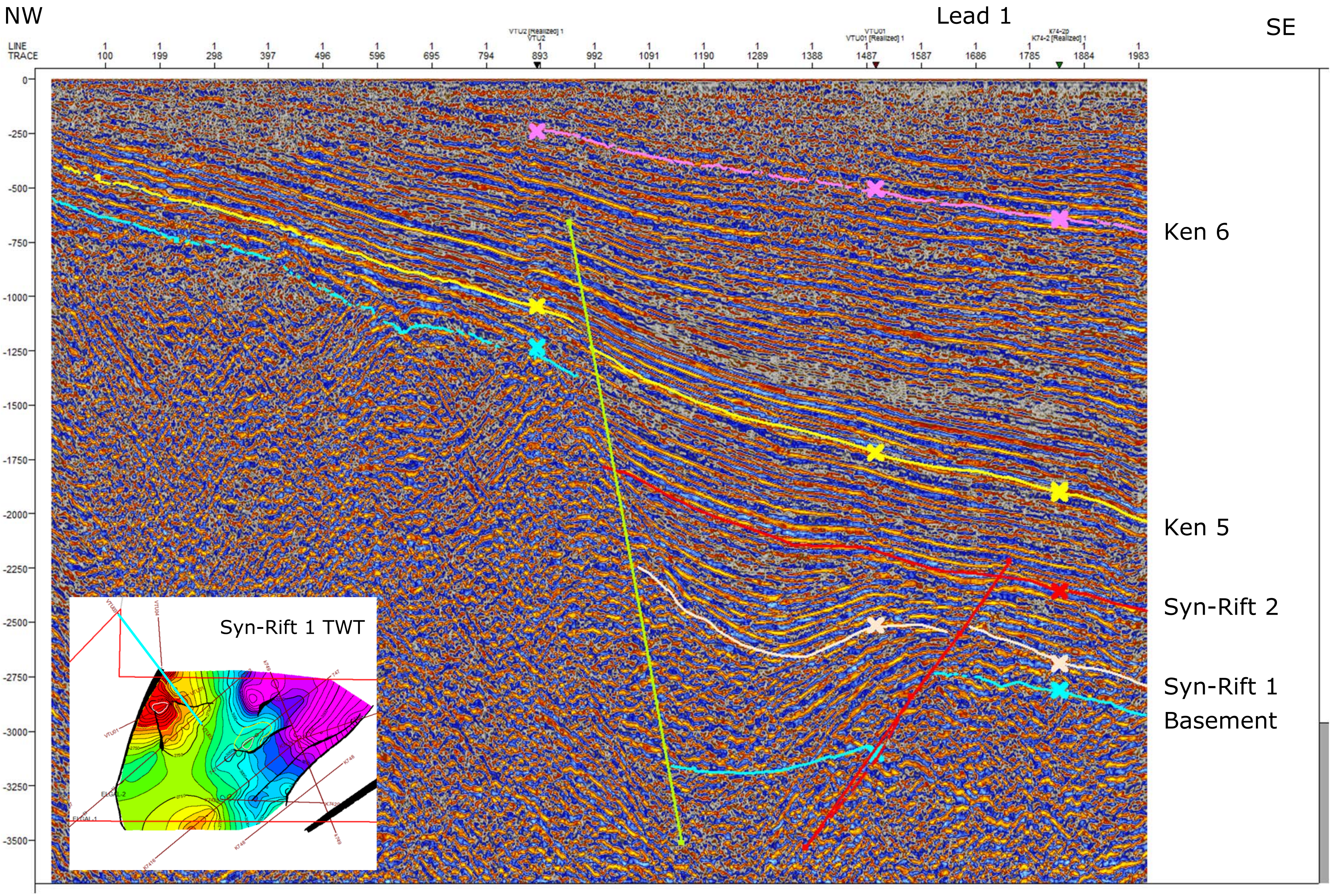
Surface Geology & Basement Faulting, Well and Seismic Control, Interpreted Fault Lineaments from Gravity / Magnetics, and Block Boundaries

Figure 16

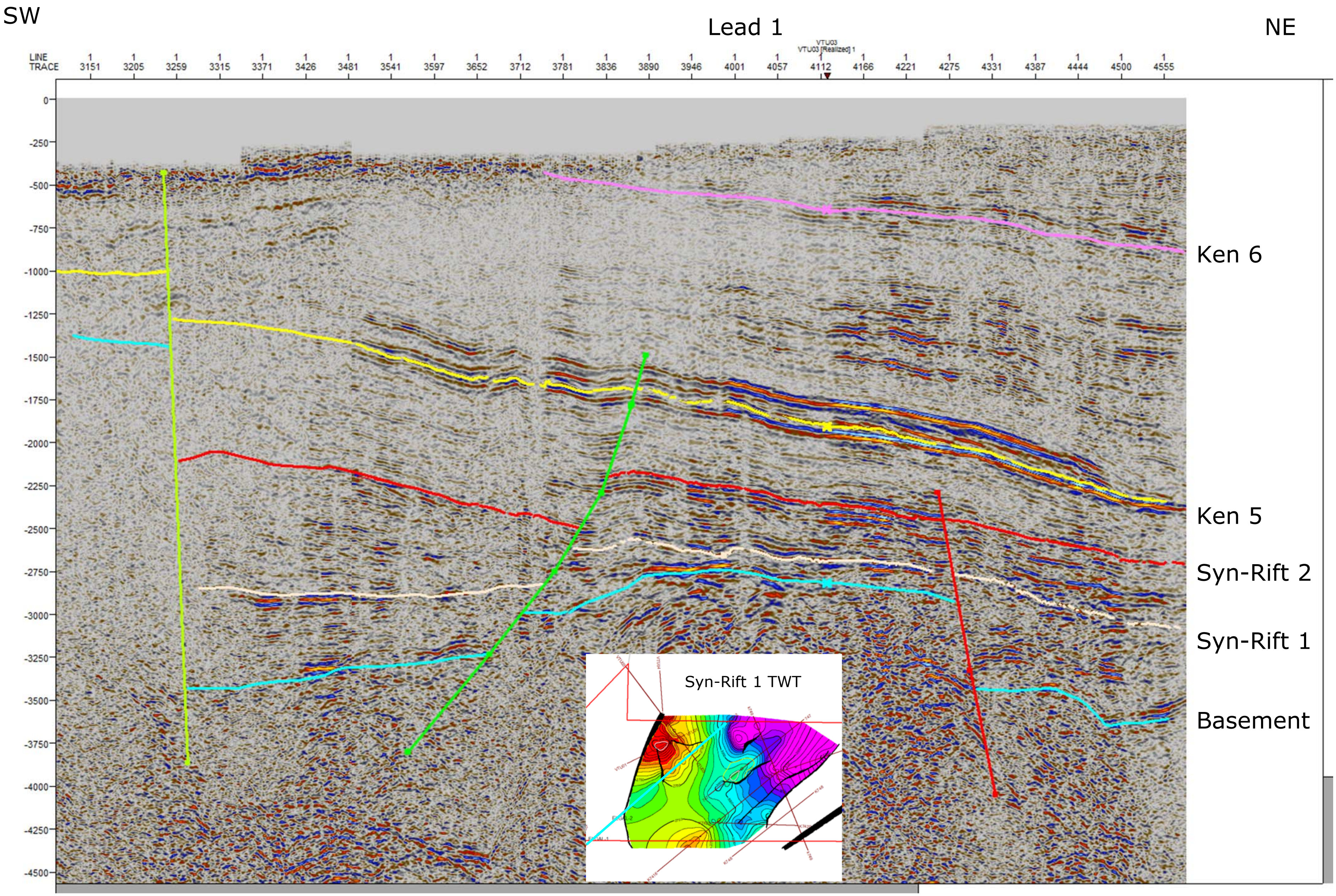
Sproule



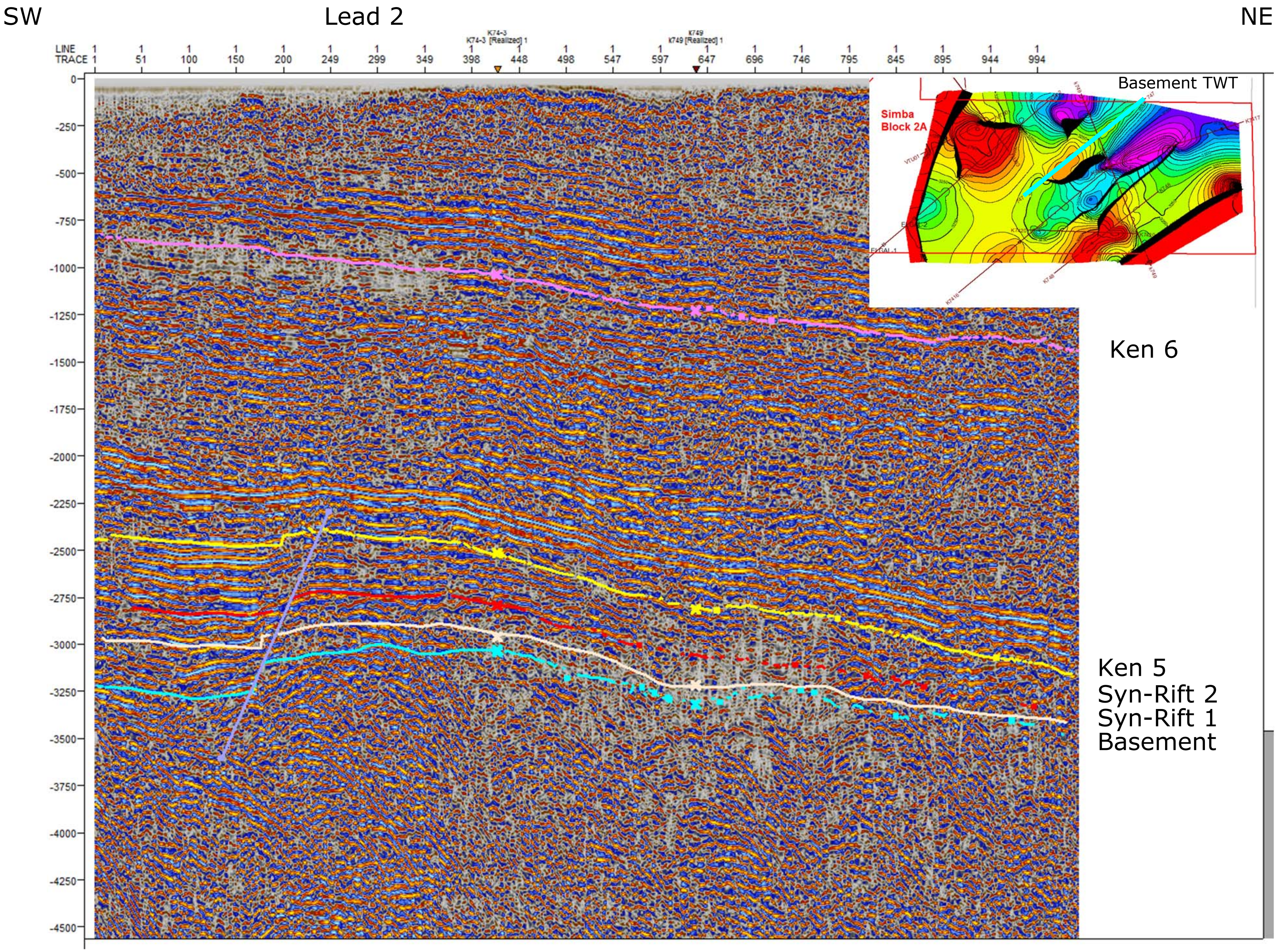
Lead 1 – SW-NE 2D Line VTU01



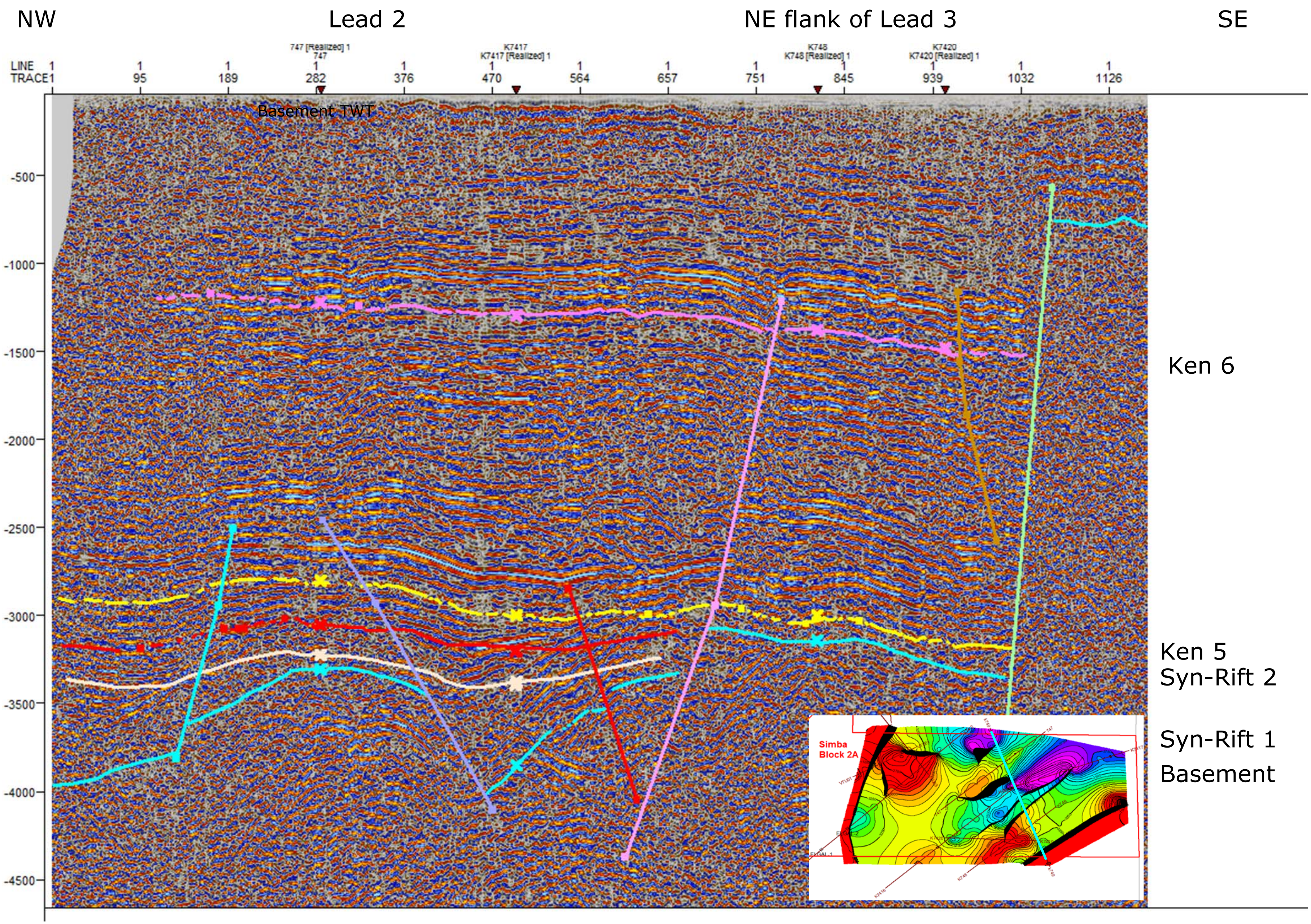
Lead 1 – NW-SE 2D Line VTU03



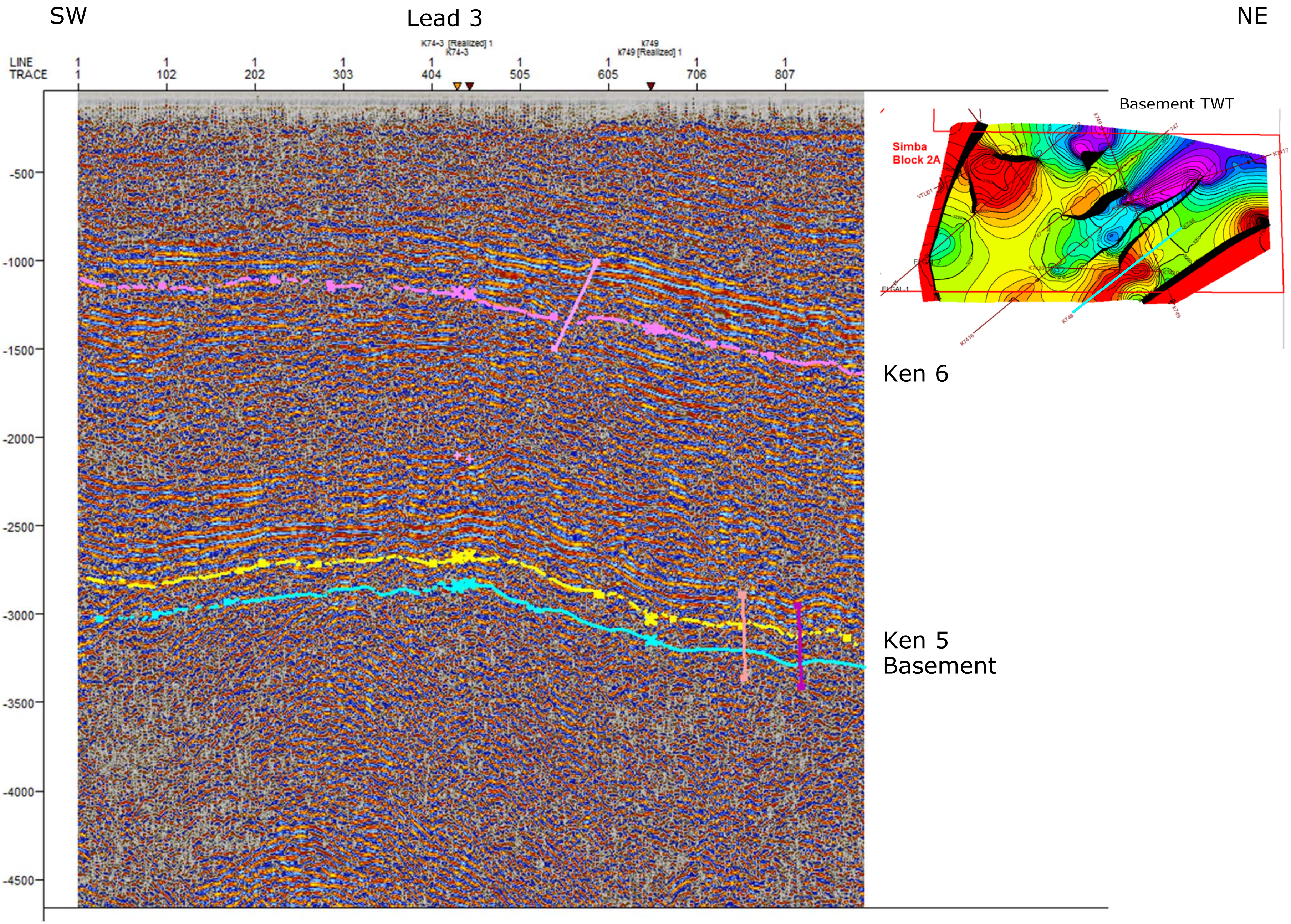
Lead 1 – SW-NE 2D Line KT742



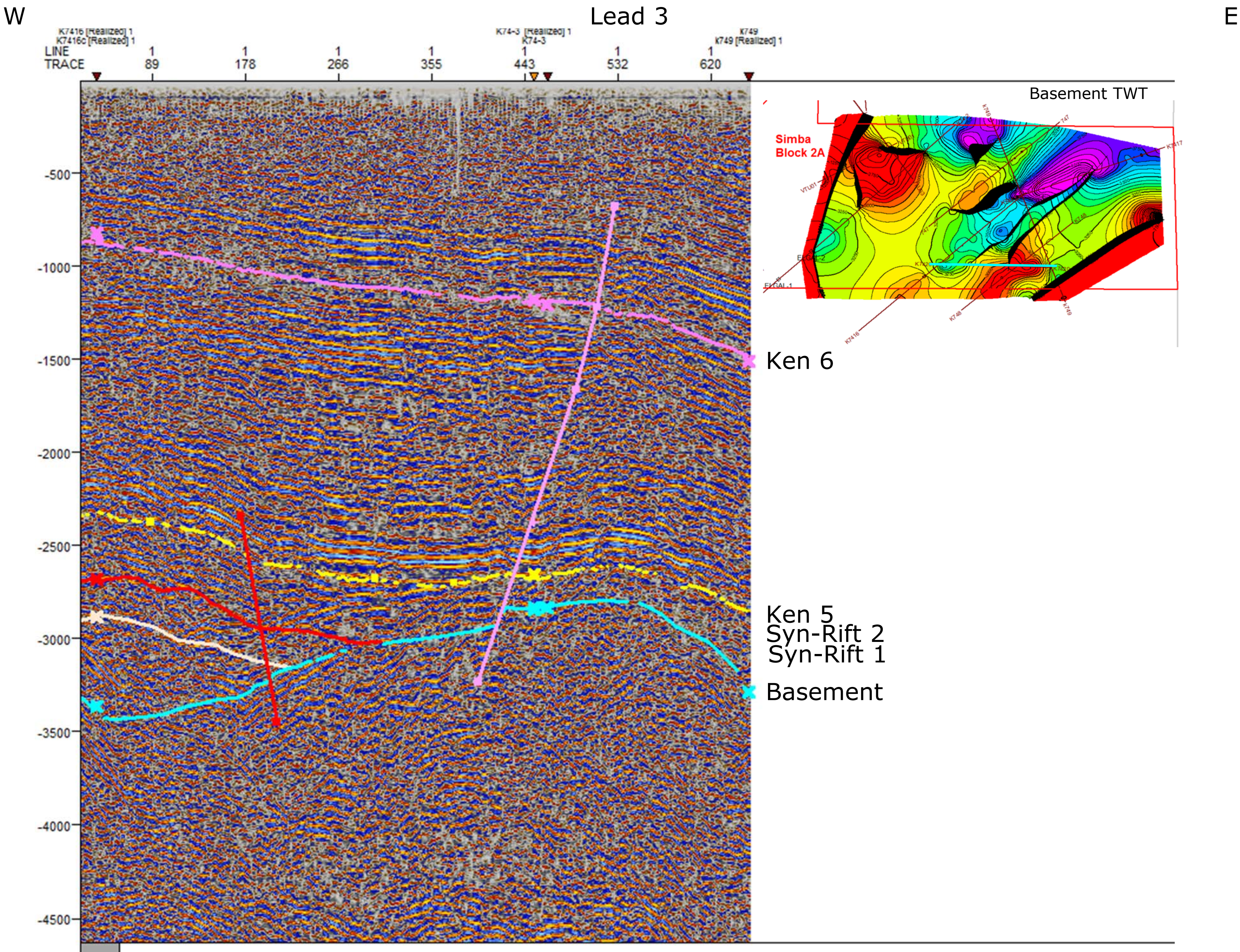
Lead 2 – SW-NE 2D Line 747



Lead 2 and 3 – NW-SE 2D Line KT749



Lead 3 – SW-NE 2D Line KT748



Lead 3 – W-E 2D Line KT7420

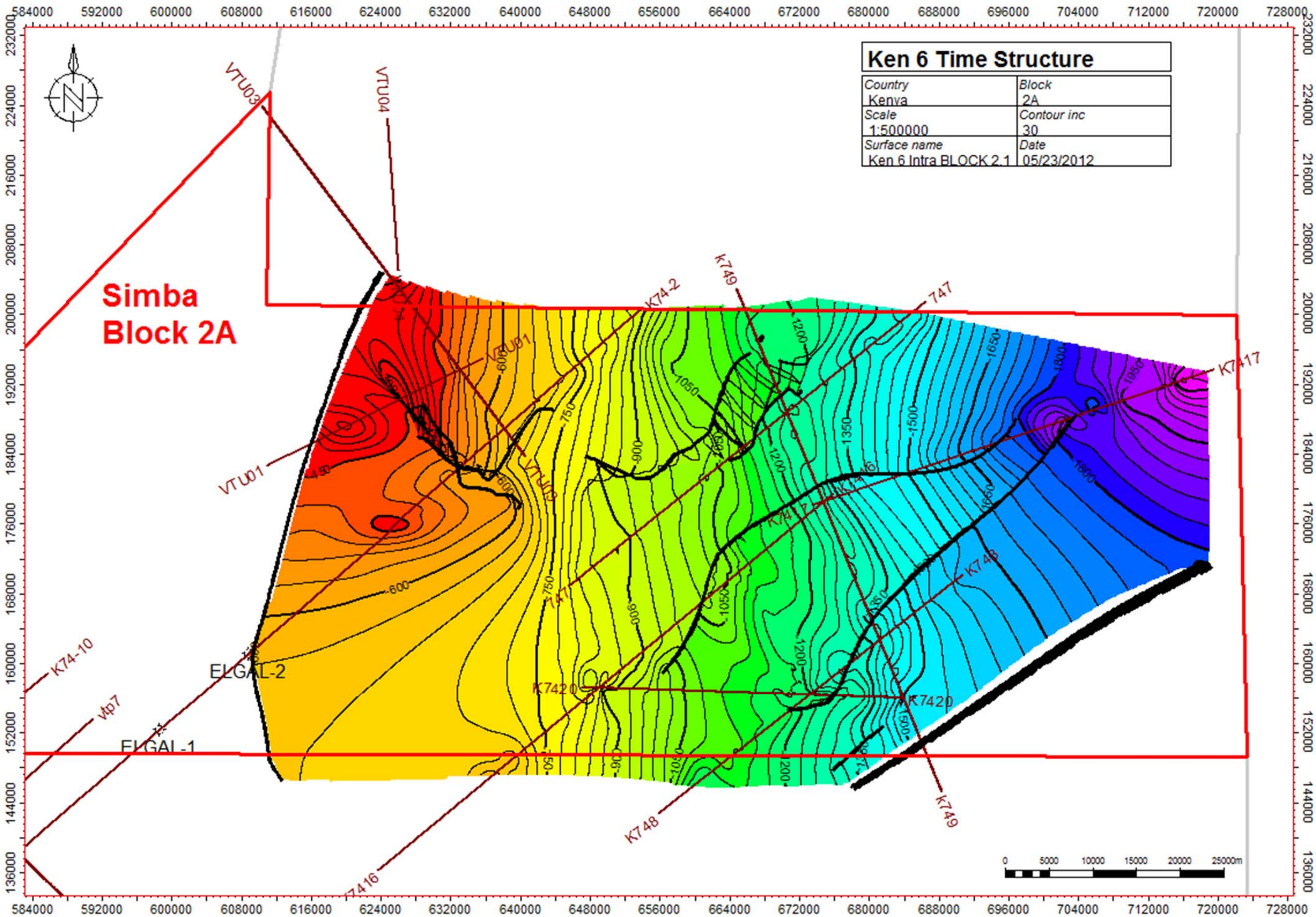


Figure 24

Sproule

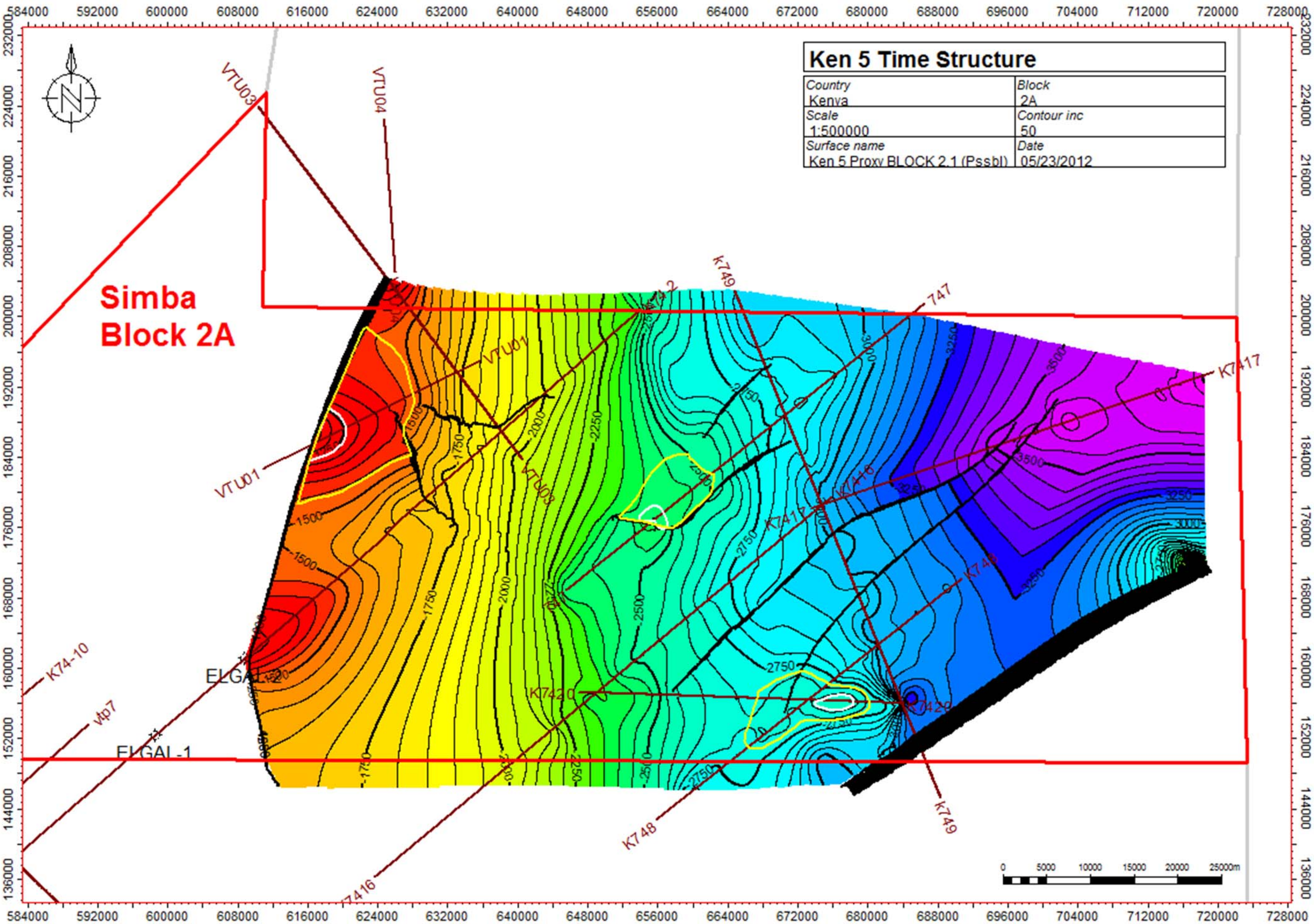

Ken 5 Time Structure
Country
Kenya
Block
2A
Scale
1:500000
Contour inc
50
Surface name
Ken 5 Proxy BLOCK 2.1 (Pssbl)
Date
05/23/2012
Simba
Block 2A
ELGAL-2
ELGAL-1
VTU01
VTU03
VTU04
K7417
K748
K749
K7420
K7416
747
K74-10
vlp7

Figure 25

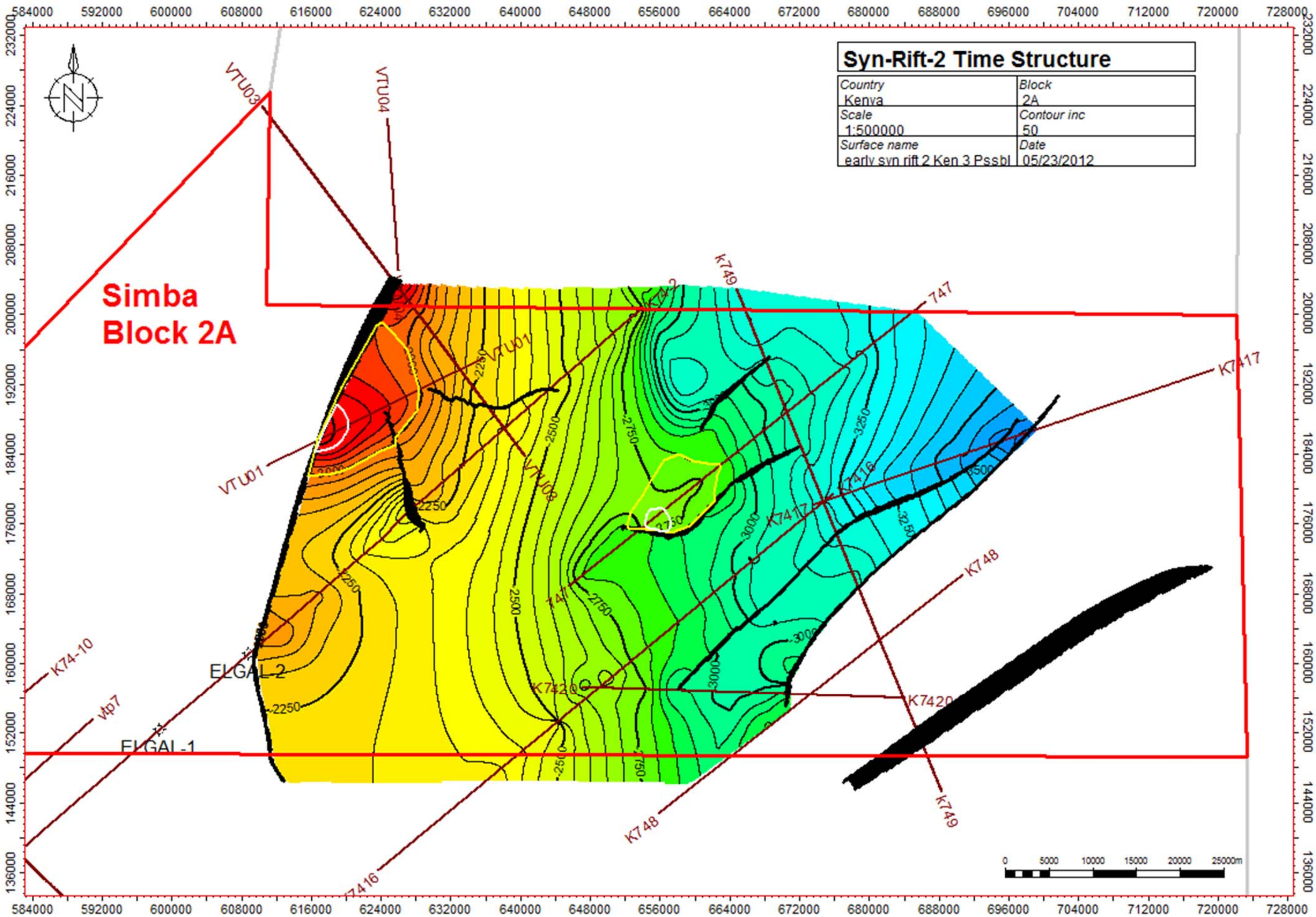
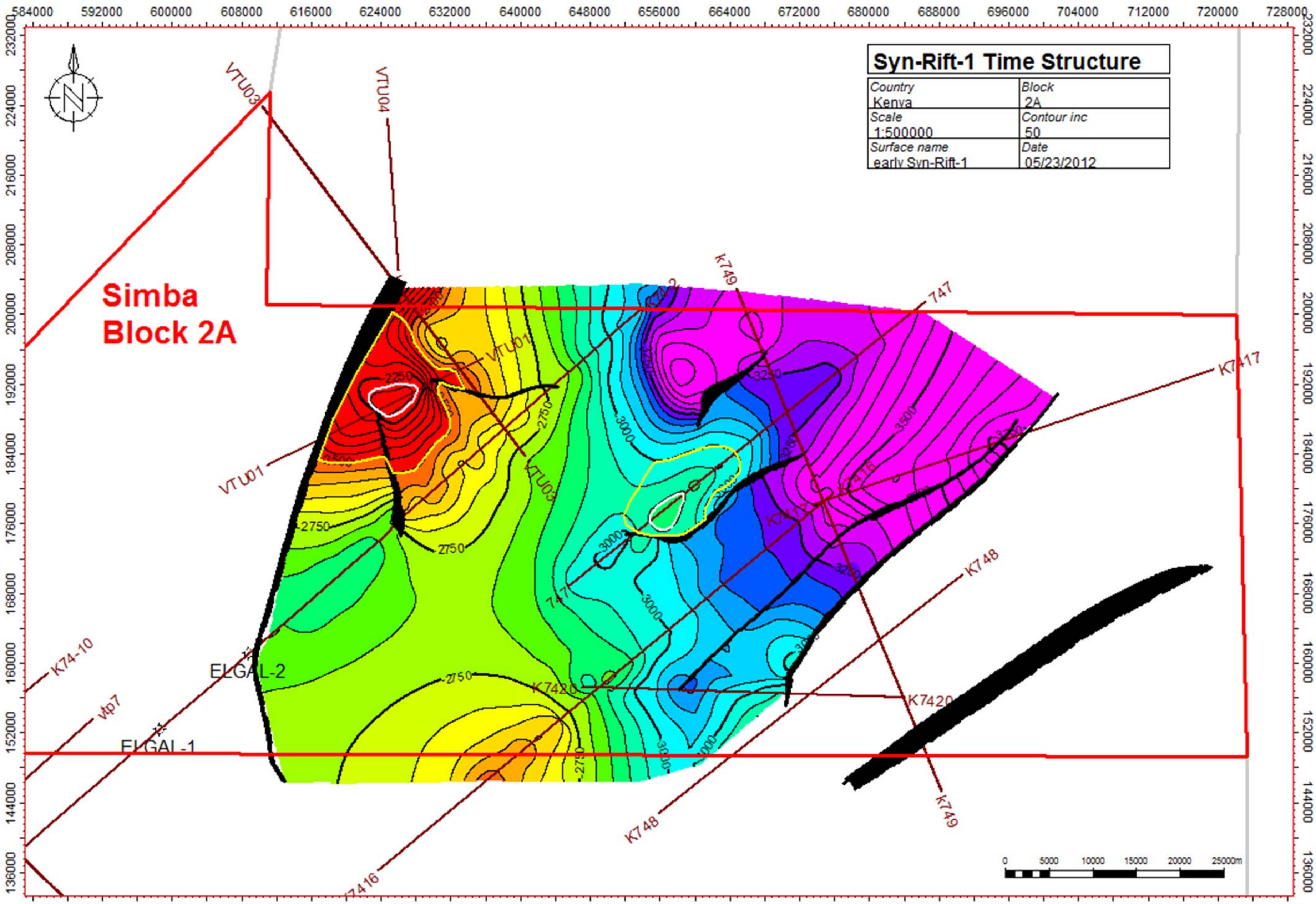


Figure 26

Sproule



Sproule

Figure 27

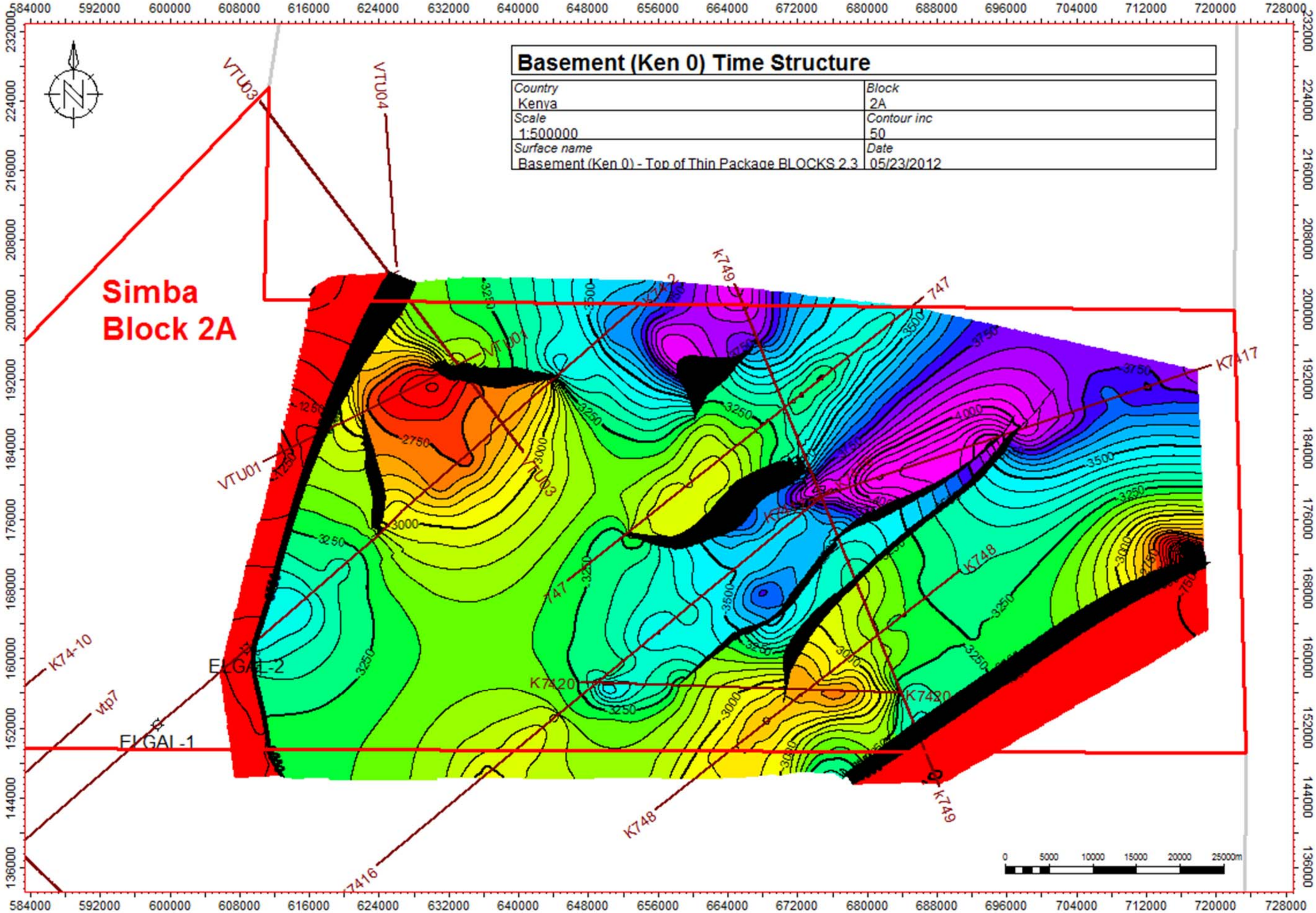


Figure 28

Sproule

Appendix A

Resource Definitions

This discussion has been excerpted from Sections 5.2 and 5.3 of the Canadian Oil and Gas Evaluation Handbook, Second Edition, September 2007.

The following definitions relate to the subdivisions in the SPE-PRMS resources classification framework and use the primary nomenclature and concepts contained in the 2007 SPE-PRMS, with direct excerpts shown in italics.

Total Petroleum Initially-In-Place (PIIP) is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent44 to "total resources").

Discovered Petroleum Initially-In-Place (equivalent to discovered resources) *is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.* The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.

> *Production is the cumulative quantity of petroleum that has been recovered at a given date.*
>
> Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status.
>
> *Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations* using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered

recoverable quantities associated with a project in the early evaluation stage. *Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.*

Unrecoverable is that portion of Discovered or Undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

Undiscovered Petroleum Initially-In-Place (equivalent to undiscovered resources) *is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered.* The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources," the remainder as "unrecoverable."

Prospective Resources are 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 subclassified based on project maturity.

Resource Categories

Due to the high uncertainty in estimating resources, evaluations of these assets require some type of probabilistic methodology. Expected value concepts and decision tree analyses are routine; however, in high-risk, high-reward projects, Monte Carlo simulation can be used. In any event, three success cases plus a failure case should be included in the evaluation of the resources (see Section 9 of the Canadian Oil and Gas Evaluation Handbook for details on these methods).

When evaluating resources, in particular, contingent and prospective resources, the following mutually exclusive categories are recommended:

- Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P_{90} confidence level.

- Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term is a measure of central tendency of the uncertainty distribution (most likely/mode, P_{50}/median, or arithmetic average/mean).

- High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P_{10} confidence level.

Company Gross Contingent Resources are the Company's working interest share of the contingent resources, before deduction of any royalties.

Company Net Contingent Resources are the gross contingent resources of the properties in which the Company has an interest, less all Crown, freehold, and overriding royalties and interests owned by others.

Fair Market Value is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

Appendix B

National Instrument 51-101, Disclosure of Resources

The following text has been excerpted from Sections 5.9 and 5.10 of National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities, May 2008.

5.9 Disclosure of *Resources*

(1) If a *reporting issuer* discloses *anticipated results* from *resources* which are not currently classified as *reserves*, the *reporting issuer* must also disclose in writing, in the same document or in a *supporting filing*:

(a) the *reporting issuer's* interest in the *resources*;

(b) the location of the *resources*;

(c) the *product types* reasonably expected;

(d) the risks and the level of uncertainty associated with recovery of the *resources*; and

(e) in the case of *unproved property*, if its value is disclosed,

(i) the basis of the calculation of its value; and

(ii) whether the value was prepared by an *independent* party.

(2) If disclosure referred to in subsection (1) includes an estimate of a quantity of *resources* in which the *reporting issuer* has an interest or intends to acquire an interest, or an estimated value attributable to an estimated quantity, the estimate must

(a) have been prepared or audited by a *qualified reserves evaluator or auditor*;
(b) relate to the most specific category of *resources* in which the *resources* can be classified, as set out in the *COGE Handbook,* and must identify what portion of the estimate is attributable to each category; and

(c) be accompanied by the following information:

(i) a definition of the *resources* category used for the estimate;

(ii) the *effective date* of the estimate;

(iii) the significant positive and negative factors relevant to the estimate;

(iv) in respect of *contingent resources*, the specific contingencies which prevent the classification of the *resources* as *reserves*; and

(v) a cautionary statement that is proximate to the estimate to the effect that:

(A) in the case of *discovered resources* or a subcategory of *discovered resources* other than *reserves*:

"There is no certainty that it will be commercially viable to produce any portion of the resources."; or

(B) in the case of *undiscovered resources* or a subcategory of *undiscovered resources*:

"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."

(3) Paragraphs 5.9(1)(d) and (e) and subparagraphs 5.9(2)(c)(iii) and (iv) do not apply if:

(a) the *reporting issuer* includes in the written disclosure a reference to the title and date of a previously filed document that complies with those requirements; and

(b) the *resources* in the written disclosure, taking into account the specific *properties* and interests reflected in the *resources* estimate or other *anticipated result*, are *materially* the same *resources* addressed in the previously filed document.

5.10 *Analogous Information*

(1) Sections 5.2, 5.3 and 5.9 do not apply to the disclosure of *analogous information* provided that the *reporting issuer* discloses the following:

(a) the source and date of the *analogous information*;

(b) whether the source of the *analogous information* was *independent*;

(c) if the *reporting issuer* is unable to confirm that the *analogous information* was prepared by a *qualified reserves evaluator or auditor* or in accordance with the *COGE Handbook*, a cautionary statement to that effect proximate to the disclosure of the *analogous information*; and

(d) the relevance of the *analogous information* to the *reporting issuer's oil and gas activities*

.

(2) For greater certainty, if a *reporting issuer* discloses information that is an *anticipated result*, an estimate of a quantity of *reserves* or *resources*, or an estimate of value attributable to an estimated quantity of *reserves* or *resources* for an area in which it has an interest or intends to acquire an interest, that is based on an extrapolation from *analogous information,* sections 5.2, 5.3 and 5.9 apply to the disclosure of the information.

Appendix C — Abbreviations

This appendix contains a list of abbreviations that may be found in Sproule reports, as well as a table comparing Imperial and Metric units. Two conversion tables, used to prepare this report, are also provided.

AOF	absolute open flow
ARTC	Alberta Royalty Tax Credit
BOE	barrels of oil equivalent
bopd	barrels of oil per day
bwpd	barrels of water per day
Cr	Crown
DCQ	daily contract quantity
DSU	drilling spacing unit
FH	Freehold
GCA	gas cost allowance
GOR	gas-oil ratio
GORR	gross overriding royalty
LPG	liquid petroleum gas
McfGE	thousands of cubic feet of gas equivalent
Mcfpd	thousands of cubic feet per day
MPR	maximum permissive rate
MRL	maximum rate limitation
NC	‘new’ Crown
NCI	net carried interest
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
OC	‘old’ Crown
ORRI	overriding royalty interest
P&NG	petroleum and natural gas
PSU	production spacing unit
PVT	pressure-volume-temperature
TCGSL	TransCanada Gas Services Limited
UOCR	Unit Operating Cost Rates for operating gas cost allowance
WI	working interest

Imperial Units			Metric Units	
M (10^3)	one thousand	**Prefixes**	k (10^3)	one thousand
MM (10^6)	million		M (10^6)	million
B (10^9)	one billion		G (10^9)	one billion
T (10^{12})	one trillion		T (10^{12})	one trillion
			E (10^{18})	one milliard
in.	inches	**Length**	cm	centimetres
ft	feet		m	metres
mi	mile		km	kilometres
ft^2	square feet	**Area**	m^2	square metres
ac	acres		ha	hectares
cf or ft^3	cubic feet	**Volume**	m^3	cubic metres
scf	standard cubic feet			
gal	gallons		L	litres
Mcf	thousand cubic feet			
Mcfpd	thousand cubic feet per day			
MMcf	million cubic feet			
MMcfpd	million cubic feet per day			
Bcf	billion cubic feet (10^9)			
bbl	barrels		m^3	cubic metre
Mbbl	thousand barrels			
stb	stock tank barrel		stm^3	stock tank cubic metres
bbl/d	barrels per day		m^3/d	cubic metre per day
bbl/mo	barrels per month			
Btu	British thermal units	**Energy**	J	joules
			MJ/m^3	megajoules per cubic metre (10^6)
			TJ/d	terajoule per day (10^{12})
oz	ounce	**Mass**	g	gram
lb	pounds		kg	kilograms
ton	ton		t	tonne
lt	long tons			
Mlt	thousand long tons			
psi	pounds per square inch	**Pressure**	Pa	pascals
			kPa	kilopascals (10^3)
psia	pounds per square inch absolute			
psig	pounds per square inch gauge			
°F	degrees Fahrenheit	**Temperature**	°C	degrees Celsius
°R	degrees Rankine		K	Kelvin
M$	thousand dollars	**Dollars**	k$	thousand dollars

Imperial Units			Metric Units	
sec	second	**Time**	s	second
min	minute		min	minute
hr	hour		h	hour
day	day		d	day
wk	week			week
mo	month			month
yr	year		a	annum

Conversion Factors — Metric to Imperial		
cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
10,000 cubic metres (ha·m)	x 8.107133	= acre feet (ac-ft)
$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf)
(@ 101.325 kPaa, 15°C)		(@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
tonnes (t)	x 0.9842064	= long tons (LT)
kilograms (kg)	x 2.204624	= pounds (lb)
litres (L)	x 0.2199692	= gallons (Imperial)
litres (L)	x 0.264172	= gallons (U.S.)
cubic metres per million cubic metres ($m^3/10^6m^3$) (C_3)	x 0.177496	= barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia)
$m^3/10^6m^3$) (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$) (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)
Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise

Conversion Factors — Imperial to Metric		
barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m^3) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m^3 (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m^3 (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m^3 (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m^3 (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m^3 (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x 0.02817399	= 1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10^3m^2)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10^4m^3) (ha·m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf)	x 0.03743222	= megajoules per cubic metre (MJ/m^3)
(@ 14.65 psia, 60°F)		(@ 101.325 kPaa, 15°C)
$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule ($/GJ)
$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= $/$10^3m^3$ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
$/bbl	x 6.29287	= $/$m^3$ (average for 30°-50° API)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m^3/m^3)
horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t)
pounds (lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m^3)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m^3)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C_3)	x 5.6339198	= cubic metres per million cubic metres ($m^3/10^6m^3$)
bbl/MMcf (C_4)	x 5.6367593	= ($m^3/10^6m^3$)
bbl/MMcf (C_{5+})	x 5.6403087	= ($m^3/10^6m^3$)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres ($t/10^6m^3$)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C_{5+})	x 161.3577	= millilitres per cubic meter (mL/m^3)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C_{5+})	x 134.3584	= (mL/m^3)
degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa·s)

Appendix D

Background on Passive Seismic Spectroscopy (IPDS®)

The following material is an excerpt from the Company's website:

Infrasonic Passive Differential Spectroscopy (IPDS) is a direct hydrocarbon indictor process which utilizes high sensitivity seismometers. The seismometers presently used are even more sensitive and are used in an extensive worldwide grid monitoring the earth's subsurface seismic activity. This grid identifies the background noise as a frequency spectrum.

IPDS detects low frequency in the 1-8 Hz range as spectral signatures over hydrocarbon reservoirs. A hydrocarbon reservoir is a frequency converter and deforms the frequency of the natural earth noise. These deformed signals on spectroscopic analysis produce unique spectral signatures which are used as Direct Hydrocarbon Indication. IPDS technology has been tested in numerous basins and reservoirs all around the world in areas including currently producing, depleted, abandoned fields and virgin reservoirs. In over 120 surveys it has proven to be correct 80% of the time which is a marked improvement in the current wildcat success ratio. Its use on Simba's Block 2A to evaluate known structures should move the Exploration program ahead by at least one or two years while reducing risk.

For more information on this technology and GeoDynamics visit www.geodynamics.it.

Sproule has not reviewed this technology before nor is familiar with the technical details of this geophysical method.