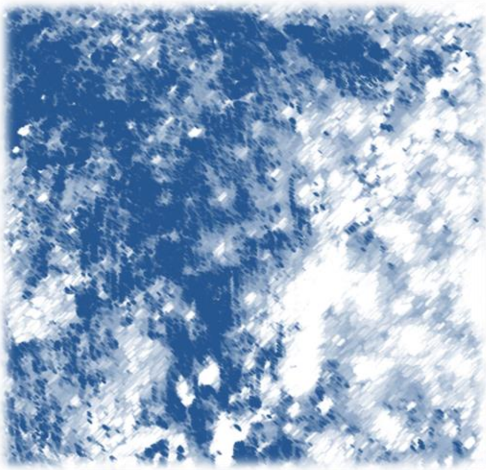

Petroleum Exploration License 68 Technical Advisory Committee Annual Update

Report on progress made in the year ended on 1st anniversary of the award of License 68 over Blocks 2219 and 2319 in Eastern Namibia

Submission to:

The Petroleum Commissioner
Ministry of Mines and Energy
Republic of Namibia

cc Africa New Energies Board

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1. Synopsis

Background

Alumni Exploration East Namibia (Pty) Ltd ("AEEN") was awarded a 90% share of the exclusive oil and gas exploration rights over Blocks 2219 and 2319 in Namibia under Petroleum Exploration License 68 ("PEL68") on 28 June 2013. The Performance Guarantee was lodged in September 2013, after which exploration could commence. AEEN is a wholly-owned subsidiary of the UK registered Africa New Energies Limited, which has raised £2.7 million over the life of the project to conduct the exploration program to date.

Exploration Innovation

ANE's competitive advantage lies in its proprietary surface exploration methodology that acquires, layers and analyses, at low cost, measured changes in multiple, discrete surface phenomena such as satellite spectral responses, geochemical signatures and tellurics data each of which act as direct hydrocarbon indicators.

This holistic approach is expected to triple the chance of drilling success when compared to traditional seismic-dominated methods. Further cost savings are achieved, by adapting South African mining rigs, drilling of exploratory wells in the Licence can be achieved at just one sixth of the cost of conventional oil and gas drilling.

Adoption of this twin thrust technological approach aims to reduce the cost of making discoveries to just one tenth of traditional techniques.

Thirty man years along with £0.7 million cash were invested by the founders towards developing the technology, prior to the award of PEL 68.

Work done to date

Since the award of the license, seven of the seventeen layers of pre-drilling evidence have been collected with encouraging results. Sophisticated mathematical processing of these data provides ANE with unique insight as to location and extent of petroleum systems and form in which hydrocarbons are trapped. Layers collected or purchased include

1. Remote and airborne gravity
2. Airborne aeromagnetics
3. Airborne Radiometrics
4. Spectral Survey

5. The start of 1st iteration geochemical sampling program using acid testing to assess n-Paraffin levels in conjunction with a new remote sensing method to predict n-Paraffin levels Basin-wide
6. The start of ground-truthing radiometric data collection for cross referencing with airborne dataset
7. Economic modelling of various success scenario's and Montecarlo simulation of the Net Present Value of discovery outcomes

This data has been augmented by knowledge from local sources (such as anecdotal evidence of oil seeps in wells, changes in vegetation, evidence of seepage and cementation) as well as review of academic literature.

The results from the 1st year work program are sufficiently encouraging for the board to recommend to shareholders to fund the completion of the pre-drilling program, after spending slightly more than the four year commitment in the first 15 months: The key finding is that the spectral survey has indicated over 2,000 km^2 across seven high quality anomalies, which have a gross mean unrisked prospective resource of 1.63 billion barrels of oil equivalent. The geochemical and ground Radiometrics collected to date are supportive of these initial satellite results. One of the anomalies covers over 1,200 km2 and has been called "The Giant", while the second most promising is in close proximity to the town of Aminius – hence the Aminius Prospect.

Future work program

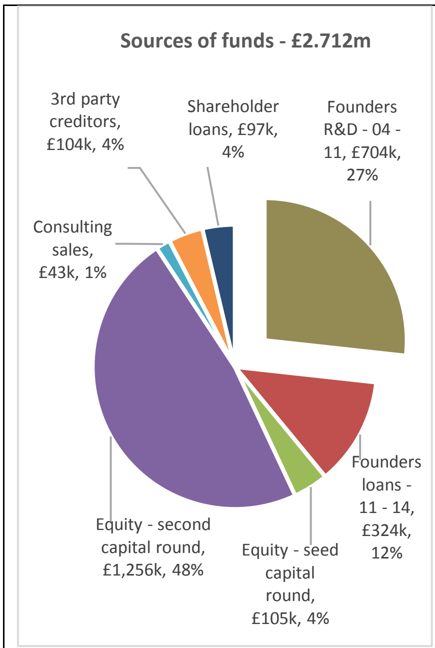
The following activities will be performed in order to complete the pre-drilling program according to ANE's methodology:

1. Geological synthesis of all known exploration data as well as investigation of macroseepage locations
2. Completion of 1st iteration geochemistry program (Soil gas content of methane, n-Paraffins and iodine)
3. Ground-truthing radiometrics and micromagnetics data collection cross-referenced with airborne and other existing datasets
4. Paleo-drainage analysis model over the Nama Basin
5. Full Tensor Gravity Gradiometry over Aminius and "The Giant"
6. Airborne Tellurics Study over the Aminius and "The Giant" Prospects
7. Ground Tellurics over Top 3 spectral anomalies
8. 2nd iteration Gore-Sorber analysis over the top 3 drilling locations.
9. Slim-well benchmark study, rig modification and approvals.

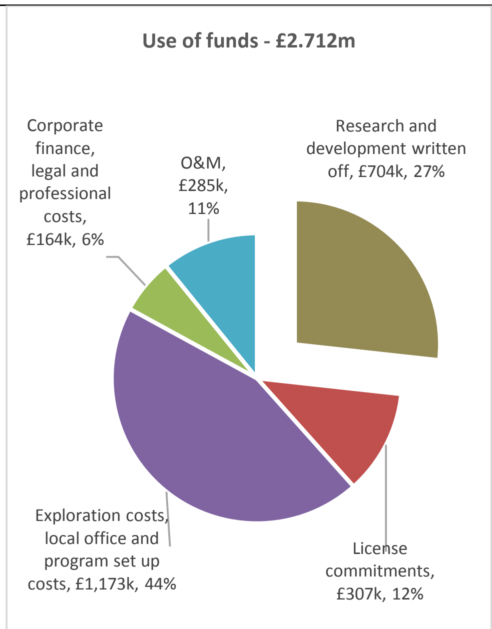
Once the pre-drilling program has been completed, the company plans to drill three slim wells using the modified mining rigs to prove the resource.

Financial highlights

To date, the founders have raised the first £1 million ($1.7 million) from their own assets and two grants –£700k ($1.2 million) contributed towards the research prior to the application for the license and £300k ($0.5 million) was contributed by the founders since license application date. Fundraising since 2013 has raised £1.7 million ($2.5 million) from investors and shareholder loans.



Source of funds to August 2014 on PEL 68, where main contributions were investment from the UK along with the founders' contributions.



Use of funds to August 2014 on PEL 68:

Of the £2.7 million ($4.3 million) invested, the initial £704k was not included in the accounts, as it was incurred towards general research and development before the date of license application. £1.2 million ($2.0 million) has been invested in direct exploration on the license in the first fifteen months – slightly above the $1.6 million commitment made in the license application.

The company plans to invest a further £2.4 million in the pre-drilling program to obtain the ten extra layers of pre-drilling evidence as per its methodology. ANE plans to continue using the same fund-raising strategy – through the crowd-funded Enterprise Investment Scheme UK investors, augmented by UK Research and Development Tax Credits. To fund the drilling program which where it intends to spud the first well in 2016 – an estimated £7 million ($11.2 million) is required, where the company plans to augment a tax efficient farm-in agreement with its existing channels with a possible AIM listing.

2. Project Background

2.1. Project Genesis

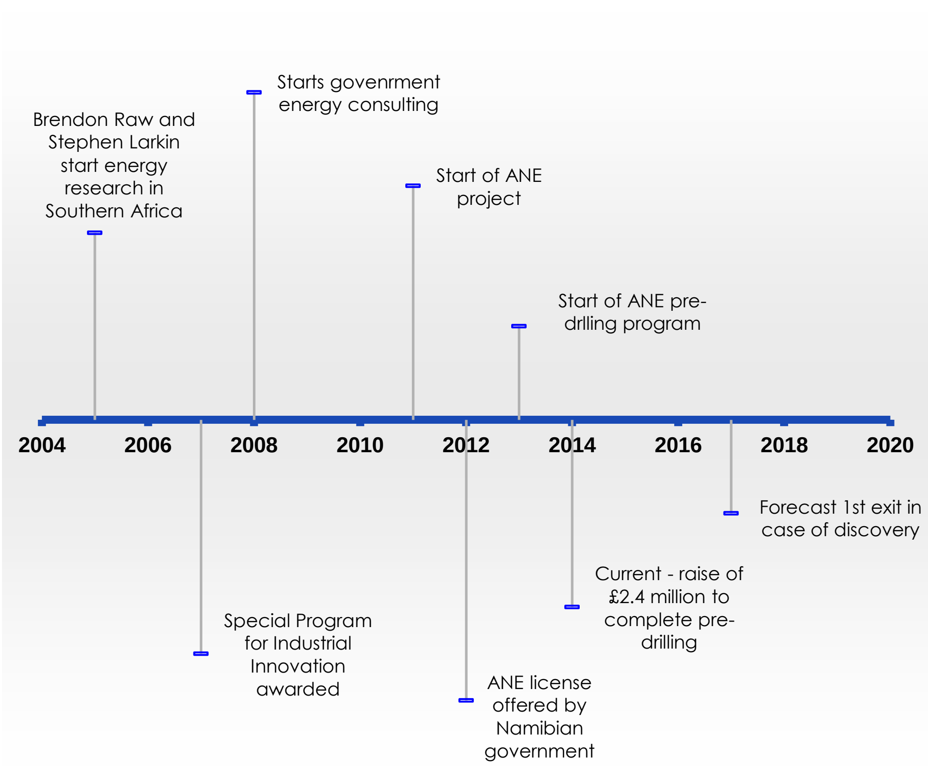


Figure 1 Africa New Energies Time Line

Stephen Larkin and Brendon Raw started researching energy innovation within the Southern African context in 2004, when they created an industrial IT innovation company originally to assist mines in the region with energy efficiency technology.

In 2009, the founders headed up a team that advised senior South African government officials on energy self-sufficiency and in 2011 was invited to advise Namibia on electricity self-sufficiency strategy. The country continues to face electricity shortages that are restricting its long term economic development and continues to need an affordable supply within its own borders. Larkin and Raw were funded by the UN-affiliated African Innovation Foundation in Zurich to devise an energy self-sufficiency strategy for Namibia that would be replicable in other African countries. The team suggested that the government need to encourage more exploration of natural gas onshore to be converted to electricity, as virtually all exploration activity was focused along Namibia's coastal margin - offshore. The licence was applied for in 2012 and was formally awarded on 28 June 2013. Raw and Larkin were joined on the board by two industry veterans, Peter Hutchison and Richard Jones formerly the head of exploration for BP Canada and the first BP Russia Manager respectively. Over a lifetime of work, Hutchison has developed a remote sensing capability that materially increases the probability of drilling success, which Larkin and Raw augmented with other surface exploration techniques. With the team, the license and a radically new exploration method in place, ANE started fund-raising in 2013, raising £1.7 million from seed capital investors, which was deployed towards its pre-drilling program. The results have been encouraging enough for the team to feel confident to raise funds to complete the pre-drilling and drilling program.

ANE owns 100% of the local SPV Alumni East Namibia (Pty) Ltd, which in turn owns 90% of Petroleum Exploration License 68 over Blocks 2219 and 2319 with NamCor, the state-owned oil company owning the other 10%.

2.2. Current shareholders and company structure

2.2.1 Ownership

The current ownership structure of ANE is as follows:-

- Stephen Larkin – 30.8%
- Brendon Raw – 30.8%
- Peter Hutchison – 6.0%
- Staff and local partners – 18.1%
- Seed capital investors – 14.3%

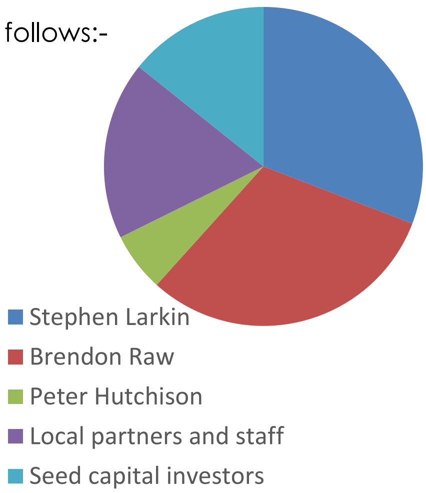


Figure 2 Current and proposed shareholding

At time of writing the company has 105,492,650 ordinary shares in issue for which it has raised £1.455 million from external shareholders over the year.

2.2.2 Group Structure

Africa New Energies Limited is structured as a holding company where its wholly-owned Namibian subsidiary, ANE Exploration East Namibia (Pty) Ltd owns 90% of Licence 68 covering blocks 2219 and 2319. NamCor, the Namibian state-owned oil company owns the other 10% of the licence, where it will share development costs post-discovery.

ANE plans to become the lowest cost explorer of hydrocarbons in Africa where it plans to use oil revenues to solve longer term electricity shortages using natural gas - eventually delivering universal electricity access to the countries hosting its projects.

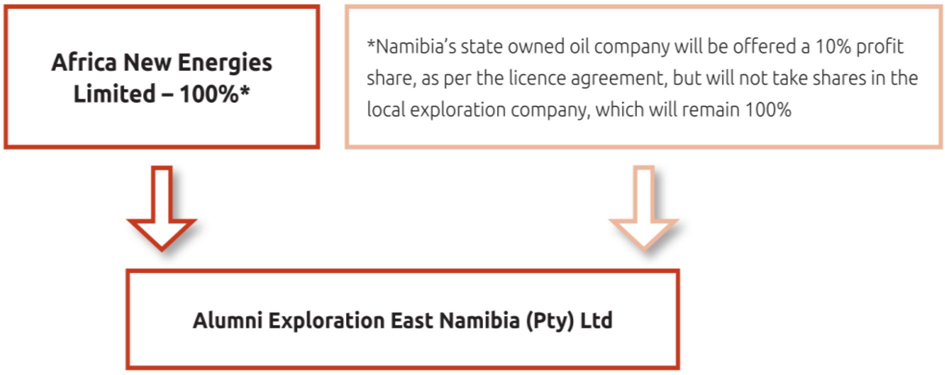


Figure 3 Africa New Energies Group Structure

ANE Exploration East Namibia (Pty) Ltd is registered under the laws of Namibia and has a share capital of 1,000,000 shares with par value of 0.1 Namibian cents per share. Africa New Energies holds 100% of these shares.

2.3. Vision

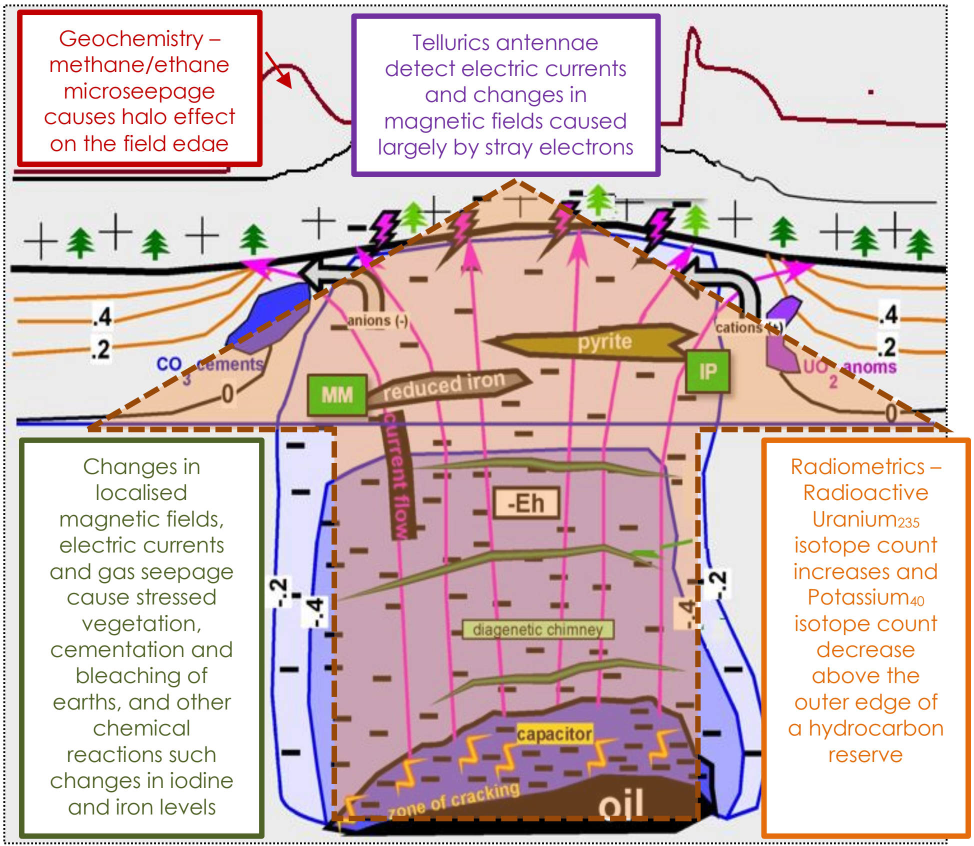
Africa New Energies plans to become the most effective hydrocarbons exploration company in Southern Africa, where it uses its combination of local community knowledge with low cost emerging technologies to find oil and natural gas at the world's lowest cost. It plans to use associated natural gas with the long term goal of providing universal access to electricity to the countries in which it operates.

2.4. Objectives and values

- To be the world's lowest cost finder of oil,
- To produce electricity within five years of proving natural gas reserves
- To replace the natural gas production within 20 years with an national renewables program in each country in which it operates
- To reduce host country's carbon foot print – moving from coal to natural gas

3. ANE's surface exploration techniques

3.1. Science behind ANE's surface exploration methods



ANE's exploration techniques are based on the phenomena illustrated in the diagram above, where the vast pressures in the oil is trapped cause gasses to escape to the surface and a molecular cracking process, where released electrons trigger chemical reactions on the surface, such as changes to electrical and magnetic fields as well as concentrations of radioactive isotopes such as Potassium and Uranium. These effects can be measured from satellite data, airborne surveys and ground analysis more cheaply than traditional seismic methods and if combined correctly – and are more likely to predicted correctly.

	Probability of discovery	Typical cost per km^2
Satellite	10% - 40%	$7
Airborne Survey	Indicates depth of resource	$30
Radiometric	Indicates possible field edges	$1,000
Geochemical Sampling	Up to 66% for frontier areas such as EL68	$25,000
Passive Telluric	66% after successful stratigraphic well	$30,000

Figure 4 ANE's integrated surface exploration method

3.2. ANE's exploration methodology – top level process

The research program revolves around finding and investigating seven high quality anomalies (HQAs) identified in the satellite survey. The program has been costed

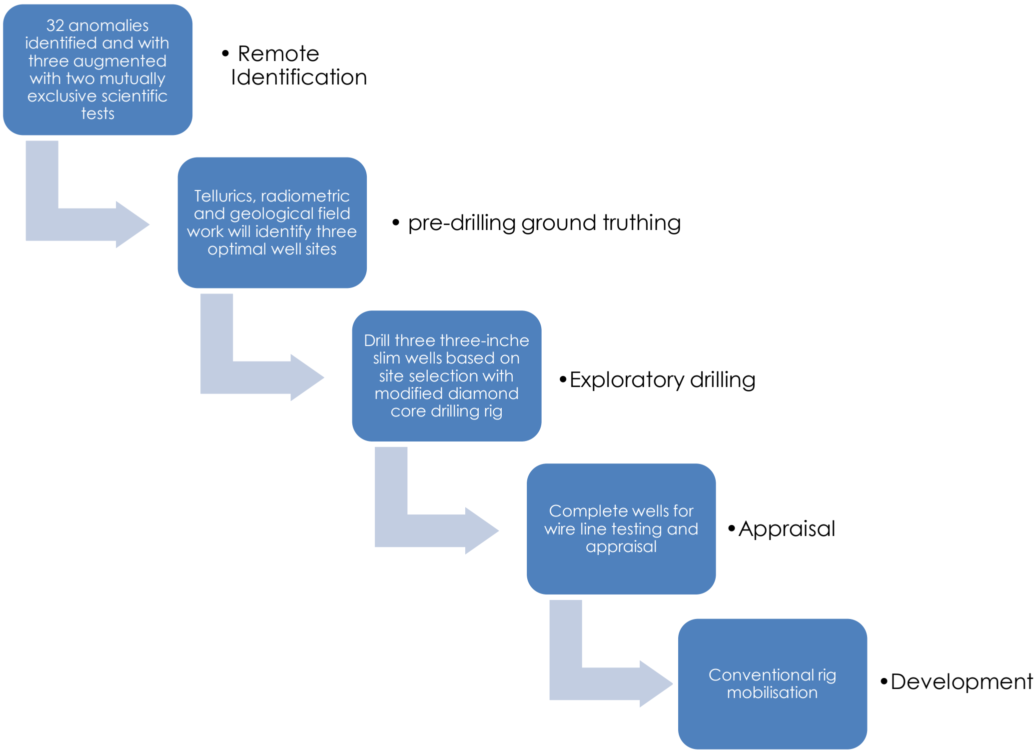


Figure 5 Process on which exploration program has been costed

3.3. Technology improvements of ANE's exploration methodology when compared to traditional approaches

Technology	Cost improvement over traditional approaches	Probability improvement traditional approaches	Evidence of academic peer review and back testing of efficacy
Satellite	Dramatic, as it can be done before a license is applied for – costing about \$7.00 per km^2 vs \$30,000 to \$200,000 per km^2, for onshore seismic with superior probability of success	Between 50% and 75% probability of discovery, when positive satellite anomalies corroborate with other surface layers such as geochemistry.	Peter Hutchison has back tested the Scotforth Satellite algorithms against over 6,000 well outcomes located across over 100 basins globally. His forecasting accuracy has had a historical prediction rate of 75%.
Transient Pulse Airborne and Full Tensor Gravity Gradiometry (FTG)Combined Airborne Survey	Provides similar, if lighter information as to the geological geometry in 2D seismic at a dramatically lower cost. Where it is less effective than 2D seismic, is that it does provide any stratigraphic insight (which 2D seismic does). 2D seismic costs \$2,000 - \$10,000 per line km onshore in Africa, while the combined survey costs \$150 per km, a 60 fold improvement in cost.	Extent to which FTG/tellurics improves on the satellite probability has not been tested in combination so is not known. The information should rather be thought of as complimentary, as the airborne transient pulse gives an indication of range of depth of hydrocarbons at a low cost.	Pinemont Technologies Inc. has flown over 130 fields and found positive transient pulse anomalies were present in 80% of non-depleted existing fields. (LeSchack, Jackson, Dirstein, Ghazar, & Ionkina, 2010) FTG has been used extensively in East Africa where it has been regarded as seminal in the success of exploration of that region.

Geochemical sampling	In the case where samples are taken in 200 meter grids, the cost per square kilometre is $2,500, plus $1,000 cost for collection and freight. Geochemistry provides persuasive evidence as to the existence of a petroleum system in the vicinity	Gore Sober has publically stated that its historical data set showed a 66% prediction rate in frontier reserves and 93% across its full dataset.	Based on 2,770 well study on five continents. He found that within his population of wells analysed, 81% of positive geochemical anomalies resulted in discovery. 89% of negative anomalies resulted in dry wells. (Schumacher D. , 2007)
Radiometric sampling	The lowest cost of all data acquisition as the cost of equipment is already sunk. The only further cost is acquisition, which involves the time of a locally trained field operative on a quad or motorbike. Results are processed internally by ANE	Back testing on well data shows that positive radiometric results layered on geochemically anomalous areas, that the probability of drilling success of over 80% - albeit usually in conjunction with seismic. (Schumacher D. L., 2002)	Completed in 1982 by Dr Donald F. Saunders, the Natural Uranium Resource Evaluation Program (NURE) collected gamma measurement of the uranium and thorium decay series plus Potassium^{40}. In one 6 state region, the study revealed a 72.6% correlation of radiation anomalies above 706 known oil and gas fields.
Ground tellurics	Comprises a combination of magneto and electro-tellurics with radar to give a reading not dissimilar to a well log for a cost of $24,000 per 12,000 feetas opposed to a well cost of $3 million.	49% historical probability of success in the case of a positive reading (high false positive) and close to 100% success in a case of a negative reading with up to 10 meter 3D accuracy.	Information available from DMT as well as a chapter from the AAPG Case Studies is referenced. (Schumacher D. L., 2002)

3.3.1 Cost comparisons between ANE's and traditional methods

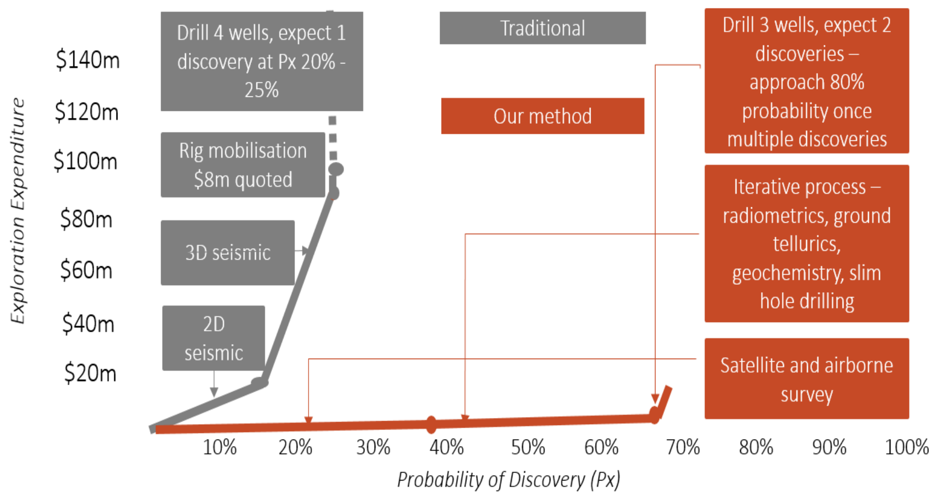


Figure 6 ANE's methods vs traditional seismic techniques

The graph across illustrates how ANE's surface exploration approach is three times more likely to succeed at 1/10th of the cost of traditional seismic dominated programs.

The typical seismic-based exploration program would involve:

1. A 2D seismic campaign would typically need to be least 10,000 km at a cost of US$2k - $10k per onshore line kilometre. This means that the initial spend would be about $20 million - $100 million with a 10% - 15% chance of success.
2. A 3D Seismic campaign would typically focus on 5-10% of the area covered by the 2D seismic study and would cost between $30k and $200k per km^2 to acquire and to interpret. Assuming a 7% 3D seismic focus area at $50k per km^2, the cost would be $70 million with a < 25% probability of success.
3. A rig would then be mobilised, where the majority of the cost of drilling lies in civil engineering preparation, transportation and mobilisation of the rig. ANE was quoted $8 million for mobilising a rig to this remote location with a 3 year wait.
4. Drilling four wells - $50 million - with < 25% chance of success

Therefore the comparable cost of a traditional exploration program is $150 million on such a frontier play, with chances of success <25%.

ANE's surface exploration approach involves using the remote sensing to highlight a 5-10% focus area for less than $500k.The pre-drilling program will cost £4 million ($7 million) and on positive results with Gore-Sober, will result in probability of success being >66%.

4. Historical exploration in the Nama Basin

Exploration for oil and gas in Namibia and Botswana has been carried out over several decades as part of a more wide-ranging pursuit of minerals. As a result, the area covered by the Kalahari Desert sands and the Drakensberg Lavas of Jurassic age has been studied mainly through the drilling of numerous shallow core-holes. For example, in 1961 Standard Vacuum Oil carried out an extensive drilling campaign (comprising over 130 shallow core-holes) which covered the entire Kalahari Basin area. (Kingston et al, 1961).

Only 4 wells have been drilled in the 350,000 km² Nama Basin

4.1. Onshore Namibia

After Standard Vacuum Oil had relinquished their concession in 1962, Artnell Petroleum Company (Windhoek) began exploration activity (Wilson, 1961). A stratigraphic test well, Vreda-1, was drilled to the depth of 2,200 meters in 1963 to 1964 to establish whether potential source rocks (Schwarzkalk Limestone) extended as far east as the border with Botswana. The well was terminated in a dolerite sill without indication for hydrocarbons, and the licence area was relinquished in 1965. The Schwarzkalk Limestone was not encountered in the well.

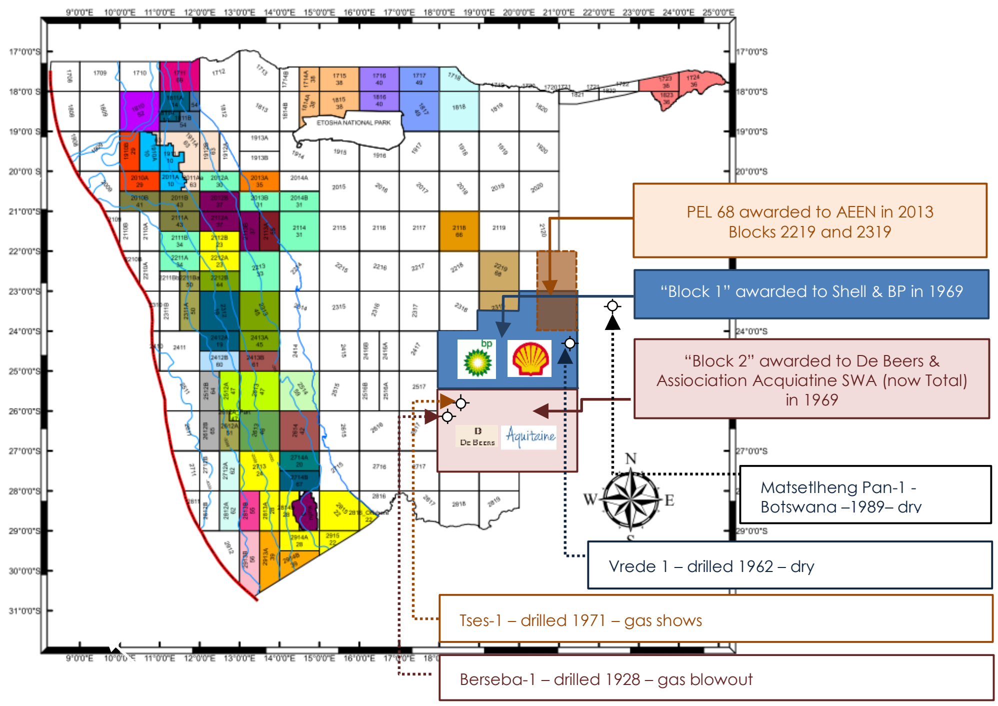


Figure 7 Companies that have previously explored the Nama Basin

Concessions were awarded to a joint venture between Shell and BP- both onshore and offshore between 1969 and 1972. Following field and photogeological studies (Wells, 1969; Shell Eksplorasie, 1969) and a sparse aeromagnetic survey was performed (Prakla, 1969). The onshore concession, Block 1, which included the Vreda-1 well location was relinquished on 1st January 1970 as well as the current Block 2319. The offshore licence was relinquished in January 1972 after acquisition and interpretation of some 2,100 km of seismic data further to the South.

At the same time that Shell and BP were conducting surveys in Block 1, Association Aquitaine SWA and De Beers Oil Holdings (Pty) Ltd held Block 2 to the South of Block 1. The Tses-1stratigraphic well was drilled in 1970-1971 following a 330-km seismic campaign. The well was located some 45km NE of the Berseba-1 test drilled in 1928 (in which a gas blow-out was violent enough to cause fatalities. (Source – anecdotal – conversation with Koujo). The concession was subsequently relinquished.

The eastern part of both Blocks 1and 2 was explored for coal by CDM (Pty) Ltd, a subsidiary of Anglo-American Corporation, in the late seventies and early eighties (McQuaid, 1985) and by Agip Coal USA between 1983 and 1984, where 36 shallow wells were drilled and some 300 million tonnes of coal resource was found within the Aranos area (20km south of the southern boundary of 2319). The concession was relinquished because the deposits defined by the drilling of shallow core-holes did not reach the minimum tonnage required for economic viability. (Agip Coal USA. 1984).

The Owambo Basin was more widely explored, where a concession was operated until 1982 by OPIC in the Etosha Basin (North of the Damara) was originally assigned to the Etosha Petroleum Company and subsequent.ly acquired by Brilund Mines (Pty) Ltd in 1962 (Etosha Petroleum Company, 1972). A farm-in opportunity was offered to Shell in1967 but was turned down (Mulder, 1967). The well Etosha West-1-5A was drilled in 1970 with reported seepage of oil into the well, at 2,507 meters were 40 gallons of light crude were encountered at the bottom of the well, while waiting for a larger rig. OPIC (a Taiwan-based exploration company) acquired operatorship of the concession from Brilund. Seismic data were acquired in the area and a well (Opo-1), planned to 4000 m, was drilled in the basin but was abandoned at a depth of 700 meters in 1991. (Petroconsultants reports, November 1991). Circle Oil controlled the

Namibian side of the Basin in the early 2000's but could not raised funding and in 2011, Hydrocarb Corporation started to explore performing gravity and aeromagnetic studies. Their program remains undercapitalised with 85% of their license area without seismic.

4.2. Botswana

Shell Coal Botswana (Pty) held exploration licenses for minerals between 1964 and the early eighties. None of the coal deposits in these concessions were developed by Shell Coal. These evaluations included a study of the hydrocarbon prospectivity of Botswana (Clark-Lowes & Yeats, 1971). No seismic data were acquired.

In 1981 to 1984, applications were made by Weeks together with Exxon for concessions in the basinal areas. Weeks relinquished their license in 1984 and Exxon subsequently withdrew in 1982, concerned about the Angolan War, civil unrest and the possibility of economic sanctions.

In 1986, the Government of Botswana and Petro-Canada International Assistance Corporation (PCIAC) entered into a cooperation agreement (with a grant from the European Development Fund) and began a 900-km seismic campaign. The stratigraphic well Masetlheng Pan-1 was drilled in 1990 to 1991 in the Nosop-Ncojane Basin in western Botswana. This well site is about 100 km East of Block 2319.

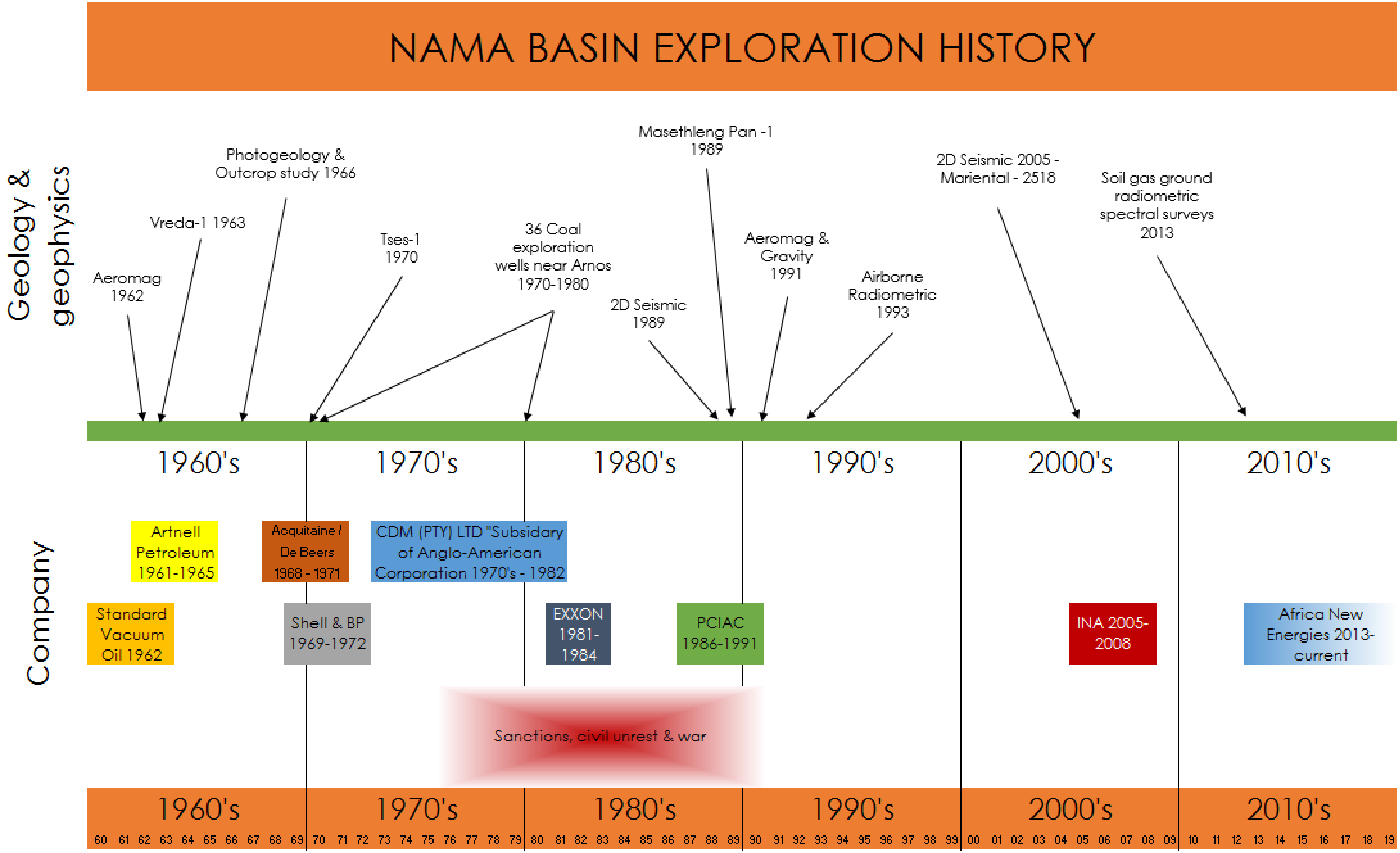


Figure 8 Nama Basin Exploration History

5. New Exploration Work Performed by ANE

5.1. Petroleum Geology of PEL68 – an opening assessment

5.1.1 Geological Overview

"THE PETROLEUM GEOLOGY OF PEL68:

An Opening Assessment"

Was written by

Peter Hutchison,

2014

ANE's PEL68 comprises two contiguous blocks of lands covering 22,000km2 of eastern Namibia abutting the Botswana border (together the "Block"). The geological setting and petroleum geology of the Block is introduced here as one of the opening steps in its exploration work programme for the initial four year term of the licence.

The sedimentary basins of southern Africa tell the story of the creation of the Gondwanaland super-continent from the earlier Rodinia super-continent in the Neo-Proterozoic to late Palaeozoic and then of Gondwana break up through Mesozoic-Cenozoic rifting into a series of younger rift basin complexes such as comprise the East African Rift System (EARS).

For onshore Namibia, this is essentially a story of

- **The Damaran Orogeny onset and climactic events of terminal Proterozoic to Cambrian age and its related southern margin foreland / foredeep sedimentary basins of Neo Proterozoic to earliest Cambrian age ("Damaran") that abut / rest on the northern flank of the Mid-Proterozic to Archaean Kalahari Craton basement and**
- **A super-posed Permo-Carboniferous to early Jurassic "Karroo" successor basin.**

For the purpose of this report and with particular respect to the geology and prospectivity of PEL68 these two basins are considered together simply as the "**Nama Basin**" or the "**Basin**" while fully recognising that each has its own record and petroleum resource attributes, yet can be influential on the other in petroleum expectation terms. Additionally, it is recognised that the Damaran basin here locates within and is integral to the Zaris sub-basin, immediately south from the SW-NE trending Damaran orogeny and its Southern Thrust Front. Its sedimentary section is up to 3 kilometres thick.

It shares a rather similar geological global plate tectonic heritage for much of its protracted Damaran cycle (650 to 180 my) with similar, contemporaneous basins in South America, Oman, Indo-Siberia and Australia. These basins all express a genealogy and stratigraphy tied closely to global late Proterozoic-Cambrian events of pre, syn and post-orogenic tectonics and their related sedimentary records of cratonic platform margins, foredeeps and foreland basins. Most notably, they share a terminal Proterorozoic Ediacaran faunal assemblage and isotopic C_{13} signature that relates to widespread source rock facies occurrences.

A protracted post-Damaran orogenic uplift and "unroofing" erosion cycle occurred from the Cambrian until the Carboniferous here. This created a peneplaned terrain for deposition of the successor "Karroo" basin.

In the late Palaeozoic (Permo-Carboniferous) renewed sedimentation created a "Karroo" successor basin of essentially siliciclastic fill. This is contemporaneous with and similar in sequence stratigraphy with the vast northern foreland basin (the Karroo Basin) of South Africa that developed there in front of the Palaeozoic Cape Fold Belt orogen.

Finally, the Basin received an overprint of early Mesozoic (Gondwana) break-up events represented here primarily by widespread lower Jurassic igneous activity (180Ma). To date, there is no evidence for major rift basin development here but in PEL68 there is a major magnetic and gravity low that could be such or possibly a localised deeper Damaran sub-basin developed to the east of the Osis Ridge of the Zaris sub-basin.

5.1.2 Exploration Status

Today, the Nama Basin is a highly under-explored, not yet proven petroleum province, yet it offers many structural and stratigraphic attributes and prospectivity elements that point towards the likely occurrence of effective petroleum systems therein. It is fortunate in having the two discrete but super-posed geological systems of the Damaran / Nama and the Karroo Supergroups present, either or both of which could be petroliferous.

This Basin is still a frontier exploration play being little tested despite a long "exploration" history. There are neither deep well penetrations within the Block's 22,000km2, nor any seismic coverage over it. However, the regional geology of the Nama Basin and its Namibian and /Botswanan surrounds are well enough known and the gravity and magnetic data over the Block indicative enough, to suggest inherent prospectivity worth exploration pursuit.

ANE are now embarked on such an exploration journey of the Block, applying modern and innovative technological approaches to accelerate exploration understanding, risk reduction and successful focusing of efforts and related risk capital expenditures. To date:

- **Conventional petroleum geological analysis** (this section) is moderately encouraging for the possible occurrence of working petroleum system(s) whilst the in-parallel
- **Hydrocarbon Lead Indicators ("HLIs") programme is very positive thus far** (separate reporting).

Together, this twin-track exploration campaign is offering positive prospectivity encouragement for PEL68 to merit its further progression as an emerging frontier play district.

5.1.3 Exploration Data

The regional geological history, tectonics and stratigraphy of the southern African basins and the "Karroo" (late Palaeozoic-Mesozoic) have been widely studied and published.

At national Namibian level, the comprehensive geological and geophysical works of the Namibian Geologic Survey are all available in Open File archives and their essence beautifully articulated in the excellent 2008 three volume publication "the Geology of Namibia" of the Ministry of Mines and Energy.

This provides excellent "Damaran" Neo-Proterozoic- basal Cambrian ("Damaran") and "Karroo" geological coverage based essentially on detailed surface outcrop geology.

In petroleum industry terms, there is no seismic coverage in the Block and only two shallow, inconsequential, wells have been drilled (ACP-1 and ACP-2). Two deeper tests have been drilled beyond the Block but within the Basin, respectively to the south in Namibia (Vreda-1) and to the east in Botswana (Maseltheng Pan-1). Neither of these found hydrocarbons. Various water boreholes exist and a number of aquifer studies made.

Data from all of these sources have been obtained, reviewed and assimilated into ANE's development of geological understanding of the Nama Basin, its petroleum potential and the prospectivity of the Block.

The initial findings are summarised here as part of ANE's reporting of progress in its PEL68 exploration programme. These simple but systematic geological observations are laid out with intent to express current knowledge, uncertainties, data constraints and key issues as milestone markers in developing ANE's forward work programme for the Block. They will be more comprehensively presented as a discrete exploration report.

5.1.4 Tectono-Stratigraphic Framework

The SW-NE oriented "macro-tectonics" of the Nama Basin and its confining adjacent structural provinces of the Damaran orogenic deformation belt to the north ("Damara"), the Gariep Belt to the West ("Gariep"), the Kalahari basement craton to the south/south-east ("Kalahari") and the penetrative, transecting major trans-Gondwanaland Southern Trans-Africa Shear System ("STASS") that stretched all the way from Namibia through Botswana and Zambia into Tanzania and beyond are well established.

The general tectono-stratigraphic framework of the Nama Basin (and its general "Southern Foreland" Damaran and successor Karroo setting) is reasonably controlled by regional geology (mainly surface outcrop data), gravity and magnetic data and to the east in Botswana some seismic control. In the Block the detailed basin fill, structural configuration and tectonic architecture and any influences of STASS events are however very poorly defined and present a major uncertainty regarding the detailed prospectivity analysis of the Block and its play fairways. Its exploration is still within its infancy – an exploration "Frontier Basin".

The geology of the late Proterozoic to early Palaeozoic Damaran Belt to the north and its Southern Foreland (the Zaris sub-basin in respect of PEL68) is comprehensively written up in the Geology of Namibia (Volume2). The Karroo is provided in Volume 3. All of this points to effective basement ("Basement") occurring at the base of the Nama Group (ca. 550Ma) below which the older, underlying Neo-Proterozoic is mildly metamorphose and unlikey to contribute to the petroleum geology of the Block unless as a fractured basement target.

The difference in structural form and deformation at each of the Basin's primary stratigraphic levels is poorly known as indeed are the detailed distribution patterns, thicknesses and lithostratigraphy of the individual chronostratigraphic units. Nevertheless, it is expected that the Damaran and Karroo structural geometries may be notably different and that this will materially impact the prospectivity of the play systems in the respective "Karroo", "Nama" and "Basement" intervals (see Section 5).

Structurally, in simplistic form, the Basin and the Block are likely to express:

- Cratonic Basement influences of fault blocks, arches and grabens – such as the Osis Ridge- directly and indirectly at all levels
- Damaran structural influences at the deeper Nama and Basement levels
- STASS extensional/transtensional influences at all levels.

Two major issues affecting the Basin are:

- the amount of post-Damaran erosion that occurred in the Cambrian to early Carbonifeorus (possibly up to 2 kilometres), prior to onset of the late Carboniferous to early Mesozoic Karroo depositional period and
- the degree of diagenetic and metamorphic degeneration of the Nama Supergroup section during the late Damaran metamorphism.

These two factors, in their own ways, may have seriously impacted both reservoir/source couplets of Proterozoic to earliest Cambrian rocks and preservation integrity of any early formed traps. On the other hand, it would be unusual for the foredeep/foreland fill of Damaran Deformed Belt to have been rendered unprospective in entirety by metamorphic degeneration, particularly as one moves southwards away from the Damaran Frontal Thrust.

In similar vein, the uncertain presence of local Karroo rift basin depocentres of Permian age impacts the probability of occurrence of thick early to mid-Karroo section and attainment of adequate source rock maturity.

The extent and impact of the "late Karroo" (early Mesozoic) volcanic events and erosional history of the district thereafter are also issues of considerable significance to the prospectivity of the district and PEL68.

ANE is considering its options to further its knowledge of sub-surface structural architecture as a key component of its prospectivity progression programme. These include, inter-alia, full tensor gravity gradiometry ("FTG") surveying, various telluric, transient pulse and E-M surveys and highly targeted, selective 2-D seismic surveying. Clearly, the intended future stratigraphic drilling programme will be the most critical "basin learning" milestone.

5.1.5 Stratigraphy

5.1.5.1 Overview

The stratigraphy of the Basin and the Block comprises a thin Cenozoic veneer of sands, gravels and salt pan deposits (the "Kalahari Group"), plus two older stratigraphic "Supergroups" respectively of late Palaeozoic to early Mesozoic age ("Karroo") and Neo-Proterozoic to early Cambrian age ("Nama" or "Damaran"). Older Proterozoic rocks are considered as effective basement – being either mildly (Neo-Proterozoic) or severely (Meso-Proterozoic and Archaean) metamorphosed: the pre-Nama Basement.

Petroleum geological interest rests in the Karroo and the Nama. The Kalahari is non-prospective, as in all likelihood is the Pre-Nama. The pre and syn-Damaran stratigraphy of the Nama is distinctly different from the post Damaran and syn-STASS stratigraphy of the Karroo. The stratigraphy of each of these two Supergroups is summarised as follows:

5.1.5.2 The Nama Supergroup: (Age: Late Neo-Proterozoic to basal Cambrian)

This "Nama" or "Damaran" Supergroup is a classic foredeep-foreland basin fill related to the development and convergence of the terminal Proterozoic Damaran and Gariep orogenic deformation fronts from the north and west towards the north / north-western margins of the Kalahari craton.

Depositionally, its occurrence is divided in Namibia into two main depocentres -the northern or Zaris sub-basin and the southern or Wiputs sub-basin- separated by a generally west to east trending Basement ridge (Osis Ridge)over which only thin and younger section was deposited and/or has been preserved . These sub-basins have total thicknesses in the order of 2-3 kilometres near the their depositional axes but thin to approximately just 1 kilometre on/ near the Osis Ridge.

In the northern Zaris sub-basin in which PEL 68 locates, the Nama comprises two primary sequences:

- The **Fish River Subgroup** of red brown siliciclastics derived largely form the rising, unroofed Damaran orgen to the north (foreland basin molasse).
- The older **Schwarzrand and Kuibis Subgroups** of dominantly marine shelf siliciclastics and mixed carbonates and shales, representing a progressively drowning platform ramp to the south and an adjacent, contiguous over-deepening depocentre (foredeep) towards the developing Damaran orogen in the north .

The basal part of the Kuibis is regionally widespread with a 150 to 500 metres thick carbonate ramp resting above a thin basal, transgressive sandstone unit. It rests unconformably at low angularity above Basement. This has been further sub-divided by some researchers into two members – the Omkyk and Hoogland. Thrombolite-stromatolite reefs are well developed in these members in the Zaris sub-basin – a key factor for the possible prospectivity of PEL 68. In basinward, downdip locations they become large pinnacle reefs encompassed by basinal shales.

Importantly, the Schwartzrand and Kuibis contain an excellent Ediacaran faunal assemblage that is contemporaneous and very similar to those of the petroliferous Oman, Indo-Pakistan and East Siberian Ediacaran provinces.

As currently known, the Osis Ridge is essentially covered by just the Fish River Group but basal clean overstepping sandstones and peripheral carbonate buildups are distinct possibilities for it as the foreland underwent foredeep-induced marine inundation.

5.1.5.3 The Karroo Supergroup: (Age: Permo-Carboniferous to Early Jurassic)

The geology of this Supergroup is addressed comprehensively in Volume 3 of the Geology of Namibia (op cit.) For the purpose of this study it breaks out simplistically into the following sequences:

- **Kalkrand Volcanics** of early Jurassic age (180Ma) – a major regional intrusive and extrusive event with numerous dolerite dykes and sills
- **The Neu Loore Formation** – thin red beds of Triassic age
- **The Ecca Group** – an early to mid-Permian succession of lacustrine, paralic and fuvio-deltaic -induced clastics including sandstones (known aquifers), coals and the dark grey oil prone Prince Albert and Whitehill carbonaceous shale formations
- **The Dwyka Group** – A Carboniferous glaciogenic series of "dirty" clastics – widespread across southern Africa in front of the Cape Fold Belt and its wider Gondwanaland extensions.

The Karroo will be addressed further in future ANE works. For present, the critical issue in respect of PEL68 is whether or not any actual Karroo rift basin half grabens are present in the Block, to provide for deeper burial of the Eccca Group possible oil source facies units. To the east in Botswana (Maseltheng Pan-1) the Karroo is only marginally mature.

5.1.6 Petroleum Systems and Possible Plays

5.1.6.1 Overview

The oil and gas prospectivity of the Nama Basin and in particular of the Block, comprises both conventional and unconventional petroleum resource play opportunities. They occur within both the Karroo and the Nama. The possibility of a Fractured Basement play on/ around the eastern edge of the Osis Arch is also possible.

The prospectivity and presence of any working petroleum system(s) in the Block depends critically on the presence and effectiveness of either or both of the following potential source rocks:

- The Nama's Kuibis and Schwartzrand "foredeep" shales

- The Karroo's Permian Whitehill and/or Prince Albert oil prone shales.

Additionally, the coals of the Karroo's Ecca Group may provide scope for a possible low grade coal bed methane play.

For present, taking into account the available data and using conventional exploration geological analysis, the possible existence, nature and major uncertainties of possible petroleum resource factor attributes for the occurrence of effective working petroleum systems and plays within the Block can be summarised as follows:

5.1.6.2 The Karroo

Source rocks are likely to be present in the Ecca Group; unlikely in the Dwyka Grpup. They are marginally mature to early oil window in Botswana to the east (Maseltheng Pan-1). The mid-Permian Whitehill /Albert Formations have the best probability of providing effective oil source rocks. The expected Ecca coals will provide methane –probably as shallow immature coal bed methane rather than thermogenic methane.

Reservoirs and Seals: Sandstones and sealing shales are expected within the Ecca Group, overlain variably by thin Triassic siliciclastics and lower Jurassic volcanics. The underlying Dwyka Group sequence is unlikely to provide an effective reservoir (or source).

Traps: Both structural and stratigraphic are possible; the main risks are attainment of maturity of the source rocks and preservation of traps though the early Jurassic igneous intrusive episode and subsequent Mesozoic erosion.

5.1.6.2.1 The Nama

The geology of the Zaris sub-basin and Osis Ridge complex suggests scope for a wide array of possible plays in the Kuibis and Shwartrand sub-groups of this foredeep/ foreland basin. These range from bank edge and intra-basinal reef plays to structural and combination trap (onlap) plays related to the Osis Ridge and basement related fault or drape closures.

Encouragement is taken for such possibilities from:

a) **The recognised global genetic linkage of rich black oil source rock deposition** occurrences with foredeep "turnaround" events and concomitant drowning of cratonic platforms prior to orogenic unroofing and related molasse fill of the foreland basins. Typically, this creates an effective source –reservoir-seal triplet system of black shales and carbonate build-ups. This appears to exist in the Zaris sub-basin to the west of PEL68;

b) **The known global petroliferous propensity of the Ediacaran end Proterozoic time window** (Oman, India, East Siberia etc) and

b) **The capping, 1 kilometre thick, Fish River Group** as an expected regional seal.

Critical uncertainties relate to:

- the actual presence within PEL68 (not just further west) of the Kuibis-Schwartzrand depocentre sub-groups lateral to the Osis Ridge,
- the maturity status of their source rocks and the timing of their maturation – early or late- versus trap formation. It is currently unknown whether this:
    - was achieved by the end of Damaran burial events under the Cambrian Fish River Group molasse,
    - withstood subsequent lower Paleozoic erosional losses and/or whether
    - subsequent Permo-Carboniferous Karroo loading gave it a late maturation event possibly with new trap developments and/or led to destruction of any early formed traps and the level of their final maturity (oil or gas).

5.1.6.3 The Fractured Basement:

PEL68's proximity to the Osis Ridge and the Damaran Thrust Front, plus possible much younger Karroo trans-tensional faulting, raises the additional possibility that fractured /weathered Basement (reservoir) plays will occur in the Block provided that an effective hydrocarbon charge has occurred.

5.1.7 Exploration Risk and Petroleum Resource Potential

The foregoing geological analysis suggests that on a standalone basis today, the probability of working petroleum systems within the Block and their perceived exploration risk and petroleum resource potential is as follows:

5.1.7.1 The Karroo

- Conventional Plays: Presence possible, effectiveness possible
- Unconventional Plays: Presence possible, effectiveness possible

5.1.7.2 The Nama

- Conventional Plays: Presence probable, effectiveness possible
- Unconventional Plays: Presence possible/probable, effectiveness possible
    - Mature Kuibis and /or Schwartzrand black oil shales – mature to overmature, possibly over-pressured: possibly pervasive extent.

5.1.7.3 Fractured Basement

- Conventional Combination Trap and Structural Fault Block Plays: Presence possible, effectiveness possible.

5.1.8 Summary

Overall, **the probability of working petroleum systems in the Block is considered at least moderate** and not poor by Frontier Basin standards. This relates in particular to the **predicted presence of at least one expected mature, rich source rock system (Ediacaran)**, the foreland basin tectonic setting and the possibility of multiple discrete petroleum systems.

Much further exploration investigation is still required. ANE is now preparing the next stage of its programme.

This opening assessment should be read in the context that in parallel, **ANE is pursuing a parallel programme of <u>HLI-focused remote sensing, radiometric, tellurics and geochemical surveys</u> as key components of its overall exploration campaign to determine the petroleum potential of**

PEL68 and therein, where the preferred exploration focus areas locate for further progression and de-risking.

At this juncture, **the early results of the HLI part of the programme are very positive** and add to the foregoing geological assessment to **suggest that PEL68 is indeed prospective.**

5.2. Remote sensing program – satellite analysis

ANE committed engage Scotforth to perform a Remote Sensing Direct Detection of Hydrocarbons (RSDD-H) Survey, using their satellite analysis techniques.

Scotforth base their search on the fact that sub-surface hydrocarbon deposits can influence surface landscape conditions by effecting changes in the geochemical parameters (pH, Eh) of soils, by generating secondary minerals of polyvalence elements and by changing the micro elemental composition of vegetation, the quantity and type of chlorophyll, etc.

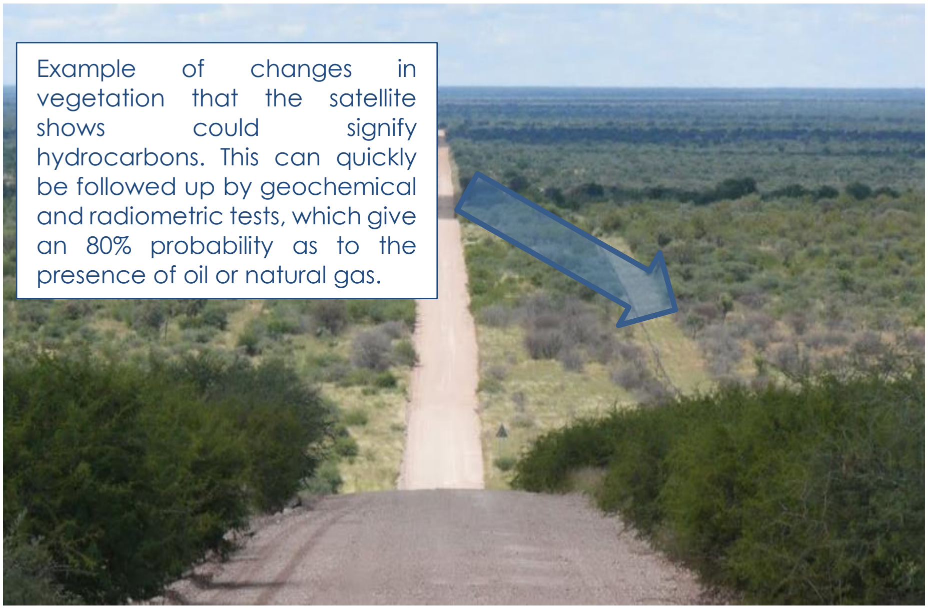


Figure 9 - one of the physical tests that Satellite tests for - physical decolouring of vegetation.

The spectral / optical characteristics of a given landscape alter accordingly - photo-spectral variances or "PSVs". RSDD-H is a mathematical, computer processing technology applied to multi-spectral satellite images, that seeks to detect and amplify such PSVs. Typically, these are second order variances, not recognisable to the naked eye on the visual bandwidth of satellite images and seldom being apparent on an area-wide basis in the natural landscape, as viewed by the eye. Occasionally, however, some local indications of the "macro-occurrence" of such PSVs are observed in the field in the change in colour of affected vegetation:

Scotforth's historical forecast accuracy is at over 70% having been tested on 100 basins on six continents.

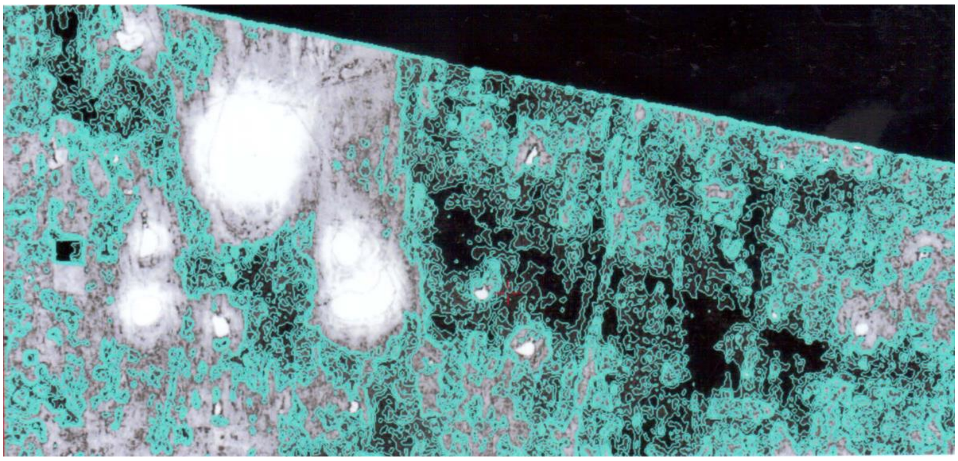


Figure 10 Example of the power of satellite analysis before ground-truthing begins – this is a high quality anomaly on Block 2319, which appears to reveal real tectonic details/faults and perhaps even "local pool targets" with high confidence.

Scotforth has completed more than 40 commercial RSDD-H exploration surveys around the world during the past ten years. These have covered more than 250,000km^2 of prospective exploration lands that range from virgin, unexplored territories to highly explored, local E&P licence areas. In addition, Scotforth has screened parts of numerous sedimentary basins and petroleum provinces in all continents, including extensive work in neighbouring Mozambique.

The success ratio of off-anomaly wells is approximately 1 in 10 versus 5 to 8 in 10 for on-anomaly wells.

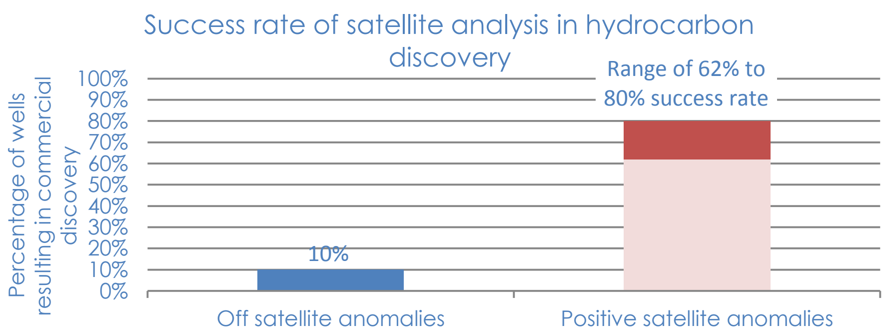


Figure 11 Success rate of satellite analysis

5.2.1 Results of the spectral survey

Scotforth Limited surveyed Blocks 2219 and 2319 which they refer to as the "Survey Area" in the executive summary below. The survey was performed in two increments and these are available in Addendum A in this report.

The satellite survey enabled license wide coverage, where direct evidence of hydrocarbons were detected over 32 prospects, of which seven were prioritised

"This Remote Sensing Direct Detection of Hydrocarbons ("RSDD-H") indicates speculative but appealing frontier hydrocarbon prospectivity in the Survey Area. It is possible that this is a significant petroleum habitat containing large volumes of hydrocarbon resources.

Five Exploration Focus Areas are mapped, they cover 9,969 km^2 or almost 44% of the Survey Area. Seven High Quality Anomalies within these Focus Areas appear to offer the best exploration potential of the Survey Area. They occupy a total area of 2,034 km2 or 9% of the Survey Area. An inventory of additional higher risk, moderate quality anomalies has also been mapped. Taken together, this suite of RSDD-H anomalous responses and patterns providers the total prospect inventory of the Survey Area (the "PI". The mapped PI occurs in both Block 2219 and 2319.

The geological habitat of the district is complex and the possible petroleum systems unproven. The RSDD-H responses are more variable than normal but do not appear to relate to any first order landscape or terrain factors. This suggests that the mapped RSDD-H prospectivity is indicative of a petroliferous basin setting.

The considerable uncertainties of the district make it prudent to model both the exploration risk and the possible range of petroleum potential. Scotforth has done this using its proprietary in-house exploration risk and petroleum resource modelling methodologies.

The Survey Area contains one extremely large anomalous feature. HGA 2, within EFA III, in the west-central sub-district. It measures (gross area) in excess of 1,200 km2 on several separate RSDD-H processed images and even under conservative processing algorithms occupies more than 800 km2. Its internal net/gross anomalous ratio is high. Such a feature, if hydrocarbon-bearing, could readily contain more than 500 million barrels oil equivalent, possibly much more. The six other HQA's in the mapped inventory range in size from 60 to 276 km^2 and could themselves offer prospective resources in the range of 25 to 250 MMBOe.

The satellite survey enabled license wide coverage, where direct evidence of hydrocarbons were detected over 32 prospects, of which seven were prioritised

The seven key features of the Survey have moderate exploration risks (1 in 4 to 1 in 7) and a "Base Case" modelled Petroleum Resource Potential ("PRP") range (in million barrels oil equivalent of Prospective Resources (potentially recoverable oil and/or gas)) of 0.8 million to 2.8 billion BOe, representing a large, appealing potential, spread across this frontier basin.

High quality anomalies ("HQA")	Mean area in km²	Petroleum Resource Potential (million barrels oil equivalent) GROSS UNRISKED			
		P90	P50	P10	Mean
1	276	106	176	367	211
2	1,218	461	810	1,690	962
3	61	21	40	84	47
4	75	31	56	118	67
5	113	46	70	150	87
6	215	92	165	353	198
7	75	30	47	99	58
TOTAL HQAs	**2,033**	**787**	**1,364**	**2,861**	**1,630**

High quality anomalies ("HQA")	Net Petroleum Resource Potential (million barrels oil equivalent) NET UNRISKED			
	P10	P50	P90	Mean
1	95	158	330	190
2	415	729	1,521	866
3	19	36	76	42
4	28	50	106	60
5	41	63	135	78
6	83	149	318	178
7	27	42	89	52
TOTAL HQAs	708	1,228	2,575	1,467

High quality anomalies ("HQA")	Chance of success	Petroleum Resource Potential (million barrels oil equivalent) NET RISKED			
		P90	P50	P10	Mean
1	14%	13	22	46	27
2	22%	91	160	335	190
3	13%	2	5	10	5
4	14%	4	7	15	8
5	11%	5	7	15	9
6	14%	12	21	44	25
7	15%	4	6	13	8
TOTAL HQAs	17%	**131**	**228**	**478**	**272**

Table 1 Gross unrisked, net unrisked and net risked prospective resources as identified the spectral survey

5.3. 1st iteration geochemistry survey

Background

ANE's surface exploration method places weight on the levels of Paraffins at the surface – as historically they indicate hydrocarbons below

Understanding the surface geochemistry is a core part of ANE's surface exploration program where occurrence of Paraffins in soils, iodine levels and finally 85 hydrocarbon molecular structures using the Gore-Sorber process, have been shown to be strongly correlated with the presence of hydrocarbons below. Academic literature suggests that positive results to these tests could yield up to a 66% probability of drilling success in frontier areas (Schumacher D. L., 2002).

Overview of exploration program to date

1st iteration 123 geochemical samples were collected and analysed by Dr Gary Rice of GeoFrontiers in Dallas, where levels of methane, ethane, ethylene, propane and propylene were measured, showing:

The 103 negative results show background levels which coincide almost exactly with the lognormal distribution of background data found on the 300+ dataset collected in Limpopo. This gives insight into the statistical probability distributions between significant and background datasets.

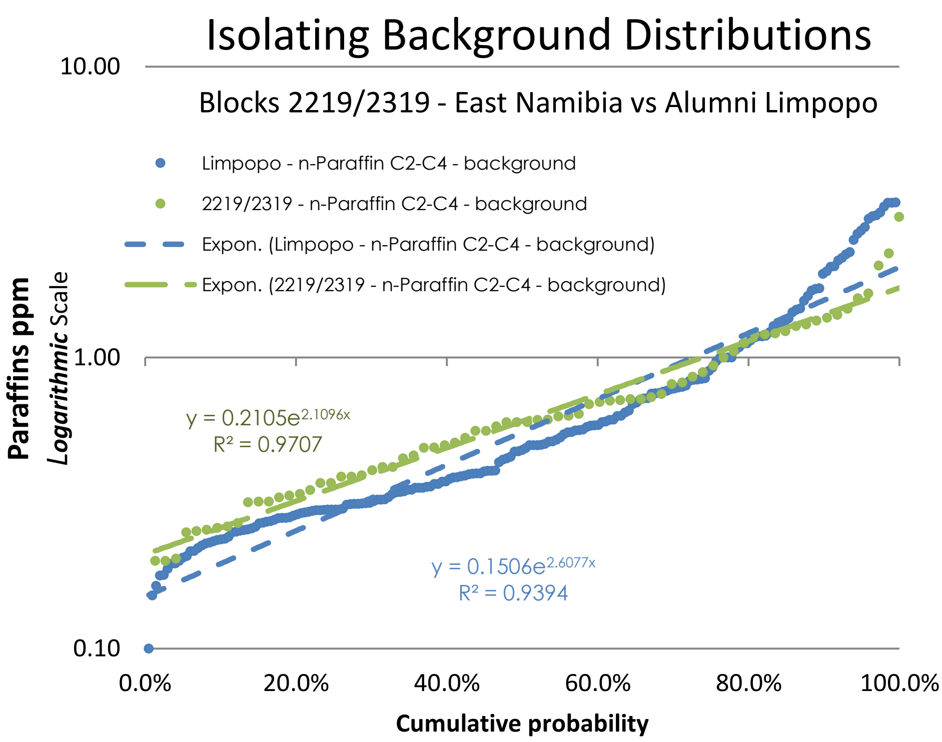


Figure 12 Blocks 2219 and 2319 vs Limpopo - background n-Paraffins levels in ppm

There are enough significant results (20) to give some assurance as to the presence of a hydrocarbon system, where the gradient of the lognormal cumulative distribution curve increases dramatically at about 2 parts per million n-Paraffins.

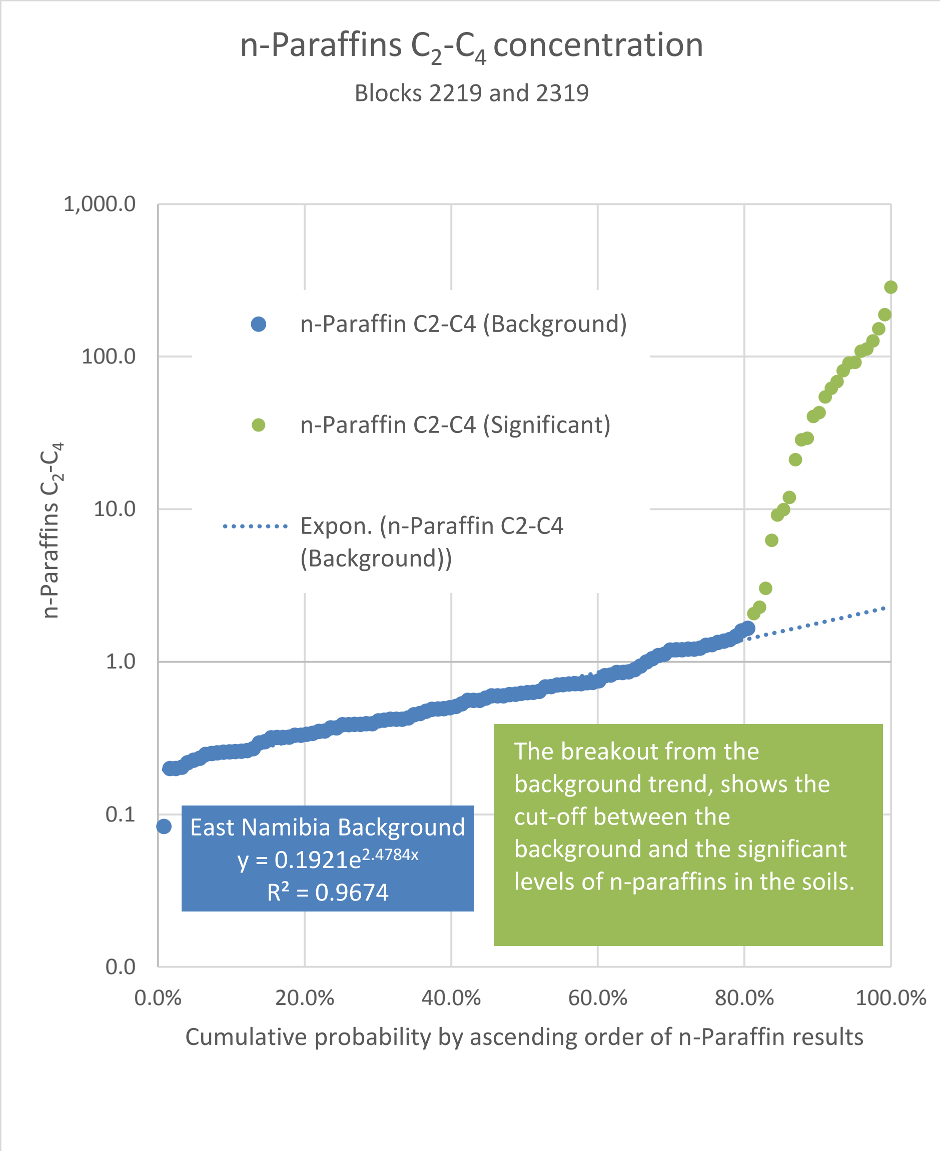


Table 2 n-Paraffins C_2-C_4 concentration – exponential representation

The significant microseepage levels seem, based on the limited data collected to coincide with reduced vegetation, cementation of soils and the salt pans. Predicting as to which distribution n-Paraffin levels will enable far more data to be generated around geochemistry of the wider Nama basin, without the need for ground sampling beyond the next stage. See below for the prediction results.

The qualitative characteristics of the categories are summarised below:

Category	n-Paraffins ppm	Characteristics and key attributes	Satellite image of typical occurrence
Background	Less than 0.6	Soils reddish colour (high clay content), vegetation unaffected – grasslands and thorn bushes of the *Dichrostachys* genus further to the north (see across), with lower lying scrub to the South.	
Intermediate	Between 0.6 – 2.0	Toxification causes cementation (greying of usually reddish soils) with the resulting toxification reduced vegetation. Best examples are North of Aminius (see picture across). The pans are dealt with under "Significant"	
Significant	>2.0	Mostly ephemeral salt pans that due to erosion are in slight depressions which was how salt and water would have accumulated – many are on the White Nossob River Floodplain and spread out over the Aminius area.	

Figure 13 Effects of soil gas seepage on the local terrain.

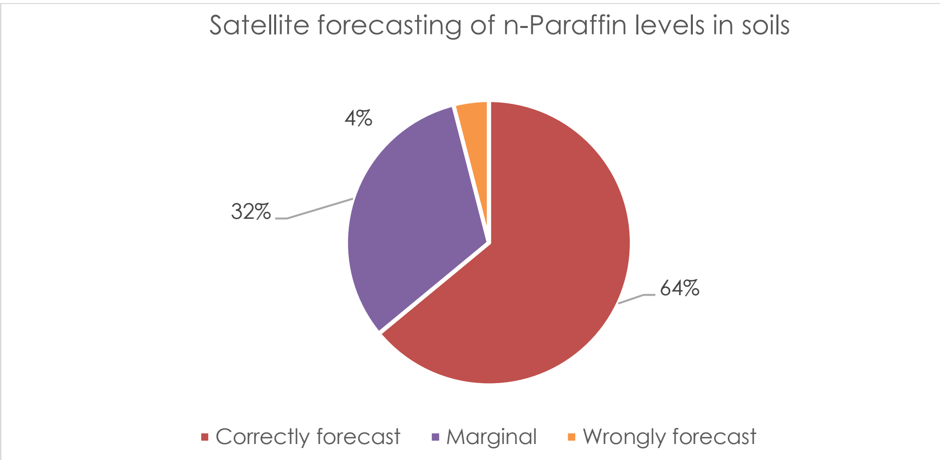


Figure 14 Ability to predict Paraffin levels in soils off Google Earth

The Ethane Composition Index provides "finger printing" of different pay zones and petroleum systems on the concession. For instance the API indicated on 2219 seems to be lower than on 2319, which indicates a light crude and condensate

.

The Ethane Composition Index analysis suggests that there are at least two different petroliferous hydrocarbon systems – one around the Taylor Formation in 2219 with medium API crudes and a second around Aminius, with lighter crudes/condensates.

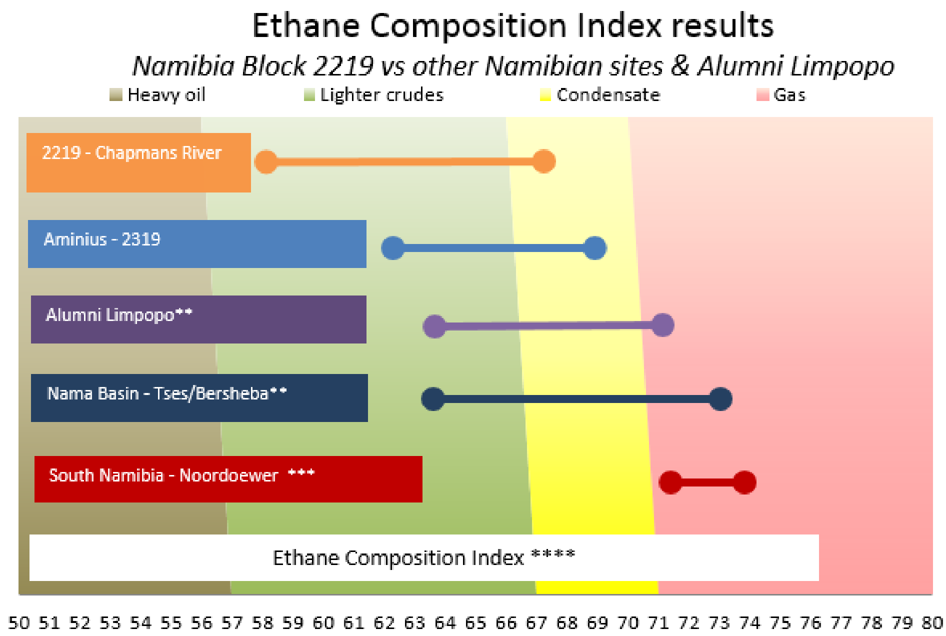


Figure 15 Ethane Composition Index ranges for five areas sampled in Southern Africa

A detailed account on geochemical sampling done to date, the academic research on which it is based and the future program is contained in Addendum B.

5.4. Initial conclusions

Initial conclusions are that the seven layers of evidence collected to date are sufficiently encouraging that further funds will be raised to invest in the completion of the pre-drilling program.

The spectral survey indicates the potential for multiple fields in what could be a major new hydrocarbons province. The seven High Quality Anomalous Areas are estimated to contain the following:

	Low – P90	Median – P50	High – P90	Mean
Gross unrisked	787	1,364	2,861	1,630
Gross risked	145	251	525	300

Table 3 Scotforth Petroleum Resource Potential range in millions of barrels oil equivalent

The initial geochemistry program is also encouraging, where the 16% of the sample population indicate significant hydrocarbon microseepage and also strong potential for cross referencing microseepage levels with visible satellite evidence of stressed vegetation and cementation of soils.

Exploration progression of the Survey Area is highly recommended, this should focus on the best HQAs including in particular, HQA 2 in the west central sub-district and the cluster of HQAs 5, 6 and 7 in the south east.

This progression should include:

- High resolution RSDD-H prospect analysis and modelling
- Conventional geological assessment and
- Highly focused new exploration surveys:
    - Further ground truthing of Radiometrics
    - Further geochemistry sampling widening the net of possible indicators to include iodine and finally Gore-Sorber
    - Ground truthing of aeromagnetics in satellite focus areas
    - Acquiring an understanding of structures by using full tensor gravity gradiometry and airborne tellurics
    - Ground tellurics to enable 3D modelling of the resource

The aim is the reduction the exploration risk of the PI, to better define the individual PRPs of its key members and rank them for further exploration.

It is recommended that exploration investment be minimised on the remainder of the Survey Area – the Low Prospectivity Zone ("LPZ") terrains.

5.5. Detailed exploration process decision tree

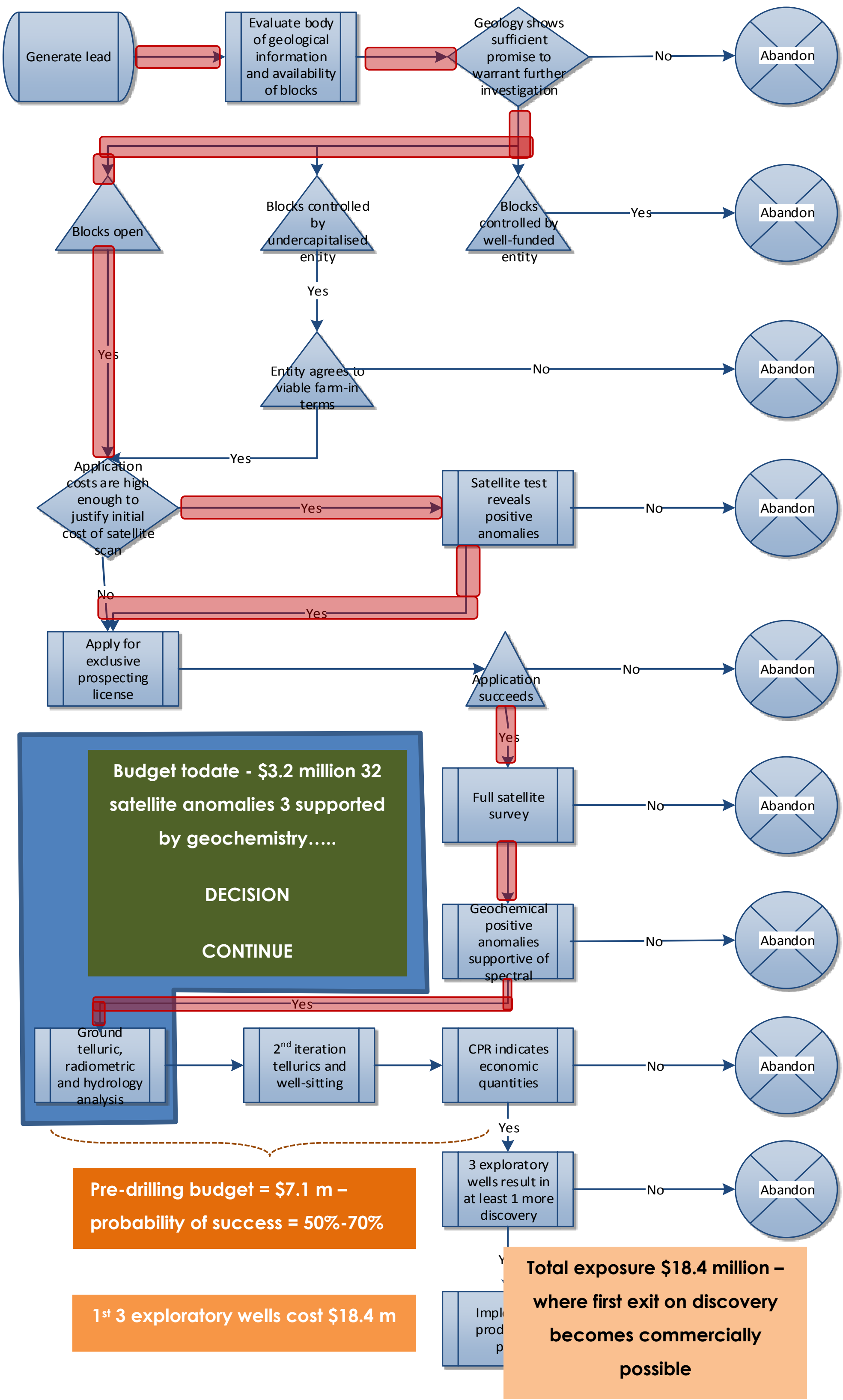


Figure 16 Decision tree

6. Completion of pre-drilling exploration program

6.1. Geological and further satellite analysis

The geological synthesis report is in the process of being written.

Scotforth Limited provided ANE with a licence-wide satellite imaging RSDD-H prospectivity survey report in November 2013. This Hydrocarbon Lead Indicator ("HLI") survey highlighted the appealing regional prospectivity of ANE's large Exploration Licence ("EL"). Since that date, further supportive evidence from ground Radiometrics and geochemical analysis has supported the conclusions of this report. ANE has decided to accept Scotforth's recommendations that it model an initial Petroleum Resource Potential ("PRP") for these lands with the aim of upgrading the definition and prospectivity status of the PEL's key features as part of the overall PRP development and exploration progression programme.

The next round of surveying will be at higher resolution, the two key focus areas (out of five) of the EL in which the best of the prospectivity locates. The results of this RSDD-H prospectivity upgrade will contribute vital HLI information for synthesis with the results of

- a conventional petroleum geology study of the EL,
- licence–wide radiometric data
- legacy gravity / magnetic data and
- surface geochemistry data

to develop a critical prospectivity appraisal of the EL. This data set will provide suitable company exploration input for preparation of an independent Competent Person's Report ("CPR") of the EL.

6.1.1 The Satellite Survey and Survey Areas

The west –central (Area 1) and south-east (Area 2) sub-districts of the EL are the target survey areas. These two areas measure respectively 4,340km^2 and 2,820km^2, a total of 7,160km^2 (the "Survey Areas"). The Area 1 surveying will extend west of the EL boundary as far as required to encompass the entire HQA 2 feature.

The key anomalous features of these two areas will be surveyed at up to 1:100,000 scale resolution, as imagery data permit. The resultant mapped prospect inventory will be geo-modelled for its refined petroleum resource potential ("PRP") with each of its members individually risked, resourced and ranked (the "Survey").

Key component of this higher resolution Survey will be to

- refine the mapping of net: gross areal extent of the individual RSDD-H anomalies in these two areas and
- reduce their exploration risk by mitigating landscape interferences in the processing stages.

A further high resolution satellite survey has been commissioned where it will focus on Aminius and "The Giant" High Quality Anomalies

The overall aim is to develop a more confident, better delineated prospect inventory with improved PRP metrics, higher risked to unrisked PRP ratios and a preferred prospectivity ranking of the prospects.

6.1.2 The Survey Report:

The deliverable product will be a standard Scotforth RSDD-H prospectivity report, inclusive of geo-referenced e-files of the prepared maps, suitable for layering / integration with ANE's other exploration data layers.

It will include:

- An RSDD-H prospectivity map (the "Map") of each Survey Area at a scale of 1:200,000 containing all significant identified RSDD-H anomalies and patterns (provided in paper hard copy and as a geo-referenced ArcGIS electronic file)
- Select prospect "core area" inset maps at a scale of 1:100,000 where attainable
- A tabulated, exploration-risked, petroleum resource potential modelled, and overall prospectivity-ranked RSDD-H inventory of the individually mapped anomalous features in the Survey Areas (the "Prospect Inventory" or "PI")
- A text commentary that discusses the PI (or lack thereof) in the Survey Areas and that provides recommendations for exploration progression
- A gallery of illustrative text figure examples selected at the sole discretion of Scotforth of the main observed anomalous features on RSDD-H processed satellite images
- A Landsat ETM+ (and/or Landsat 8 or Aster or such) vegetation composite mosaic/image (1:200,000 scale) of the Survey Area

6.1.3 Geological synthesis

The Nama Basin is underexplored and has "frontier" exploration status, which means that its geology and possible petroleum systems are poorly understood. There is however a valuable database of published academic literature and Ministry of Energy Open File reports that can be used to build a geological framework of the district and to prognose its likely petroleum systems.

The work will be performed by Peter Hutchison, through his consultancy Criffel Enterprises Limited, where he will undertake a petroleum geological study of Blocks 2219 and 2319 using these data, analogous international petroleum habitat awareness and Criffel's proprietary petroleum modelling process.

This geological study will contribute vital conventional exploration geology and petroleum prognosis information for synthesis with:

- The results of the RSDD-H HLI surveys already completed on Blocks 2219 and 2319
- License-wide radiometric data
- Legacy gravity/magnetic and 2D seismic data and well logs

To develop a critical prospectivity appraisal of the Exploration License, This data set will provide suitable company exploration input for preparation of an independent Competent Person's Report ("CPR") of the Exploration License.

The proposed Geology Study will be delivered as a standard Criffel petroleum geology prospectivity report that will include discussion of:

A chrono-stratigraphic framework and geological history

- A chrono-stratigraphic framework and geological history
- Its known and predicted lithostratigraphy and expected petroleum resource attributes
- Predicted tectonic and subsurface framework
- The possible petroleum systems and trap types
- Exploration uncertainties and risks
- A range of possible petroleum endowment richness metrics for the district.

6.2. Radiometrics

6.2.1 Scientific justification

A US government study over 508 oil fields showed that drilling on radiometric anomalies had a 72% of finding commercial hydrocarbons – with 85% of oil reserves showing.

As with other remote sensing and surface exploration techniques adopted by ANE. Radiometric analysis in hydrocarbon exploration is not conventional, a scientific justification is helpful to understand the value collecting such data provides to the overall exploration campaign.

Geologists have known since the 1950's that subsurface oil and natural gas deposits often created anomalies in terrestrial background radiation levels. These radiometric anomalies typically appear as non-random reductions in the flux below those of the surrounding natural background. These anomalies have been well documented, although the reasons for them are still being debated. The US Bureau of Mines published a review of 237 papers back in 1973 wherein 85% of them reported that such a relationship existed. Recognizing this phenomenon, the US Department of Energy conducted a 5-year long aerial map survey of the entire USA using large gamma scintillators. Completed in1982, the Natural Uranium Resource Evaluation Program (NURE), as it was called, collected gamma measurement of the uranium and thorium decay series plusK-40. In one 6 state region, the study revealed a 72.6% correlation of radiation anomalies above 706 known oil and gas fields. The principle is based on Olsen's unpublished paper that summarises the phenomenon in the following way:

"An oil/gas accumulation at depth is subjected to pressure and heat which causes catalytic cracking of the hydrocarbon molecules. This breaks the chemical bond of the molecule and the excess electrons now have a negative charge causing them to rise to the positively charged surface, where they are neutralized by readily bonding with positive hydrogen ions (possibly from near surface water). The rising hydrocarbon ions cause a vertical electrical flow (current) and magnetic field. This is why micro-seepage is always vertical."

"Measurements above microseepage are not repeatable and there are variations since the catalytic cracking slows and stops when pressure is reduced (such as happens at a producing well). The negatively charged ions stop being produced and the upward flow stops. The magnetic field dissipates and the reducing environment oxidizes the uranium compounds which become soluble and are leached away. Potassium accumulates from surface water runoff."

With a radiometric survey the gamma ray count for Potassium and Uranium is measured and on a graph, a symmetrical diversion of the 2 curves (Potassium is higher = Red and Uranium is lower = green) is the key indicator of a hydrocarbon reserve over the page:

The diagram over the page assists in visualizing the above explanation.

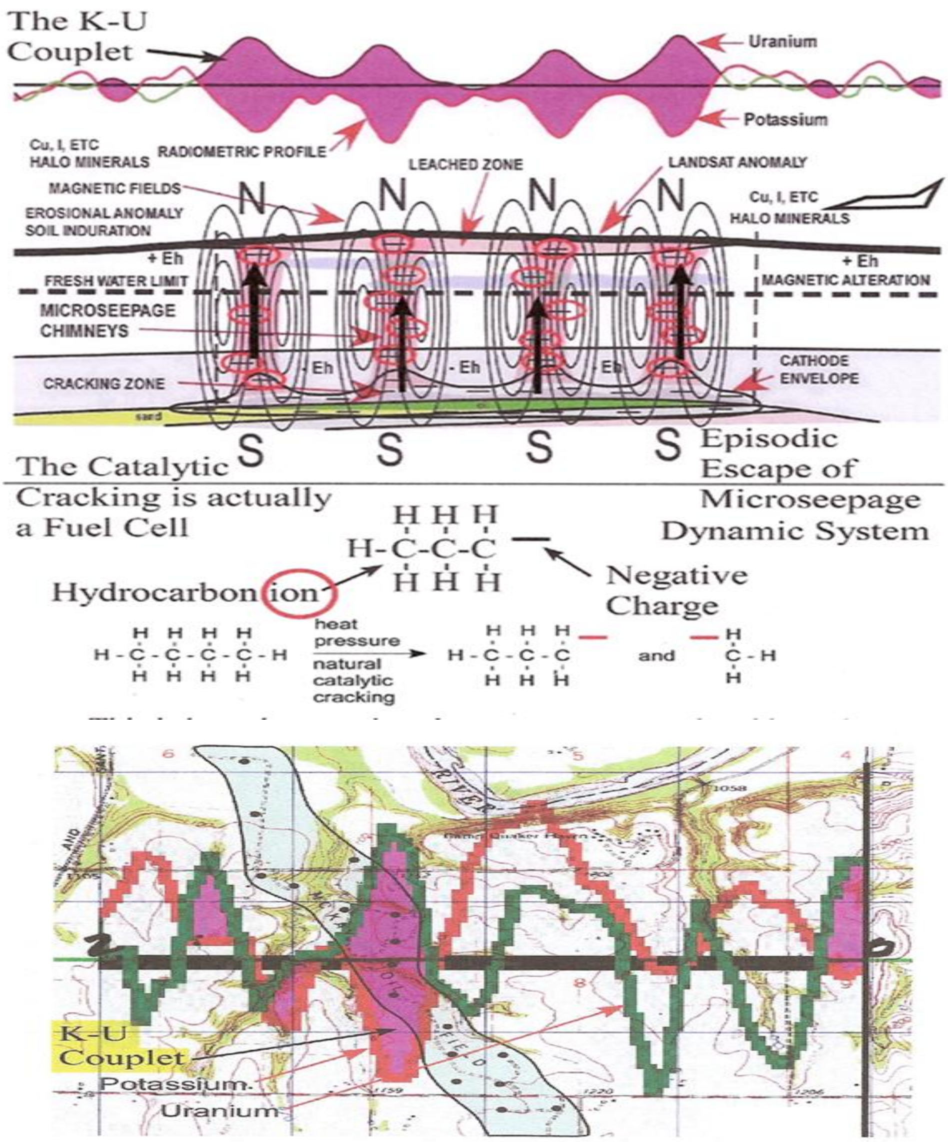


Figure 17 Illustration showing the scientific theory behind radiometric analysis – the Radiometric line processes (example used in Kansas, USA) - example showing the effectiveness of radiometric sampling – where the K-U graph is superimposed over the topographic map.

ANE has invested in a Ludlum GeoExplorer to ground-truth radiometric airborne data

In the Figure 17 Illustration showing the scientific theory behind radiometric analysis – the Radiometric line processes (example used in Kansas, USA) - example showing the effectiveness of radiometric sampling – where the K-U graph is superimposed over the topographic map. The K-U graph is superimposed over the topographic map. This is how the negative charges are generated and how the hydrocarbon ions move to the surface to be reconstituted into the hydrocarbon modules.

The map shows how plotting the reprocessed radiometric line profile data over the USGS 1:24,000 topographical maps can illustrate the anomaly style over a potential prospect. The south Kansas example across the McKay Field shows a classic Potassium-Uranium Couplet (K-U Couplet). The K-U Couplet maps produced from each of the above 3 steps are then layered; one atop the other and a master channel layer map is drawn. The master map represents locations where all 3 methods coincide on location and perimeter of anomalous areas. Over this reduced area where a passive telluric survey will be conducted to pinpoint the best locations for drilling of exploratory wells.

6.2.2 Modus operandi to date

Figure 18 - Ludlum model 4404-16 GeoExplorer

Ground radiometric data were collected using a Ludlum model 4404-16 Geo Explorer, where 150,000 data points were collected over 650 km of roads and 50 km off road around the Aminius area. While not enough data has been collected to draw statistically robust conclusions, a number of important supportive anomalies have been identified – see below for one on the Taylor Formation.

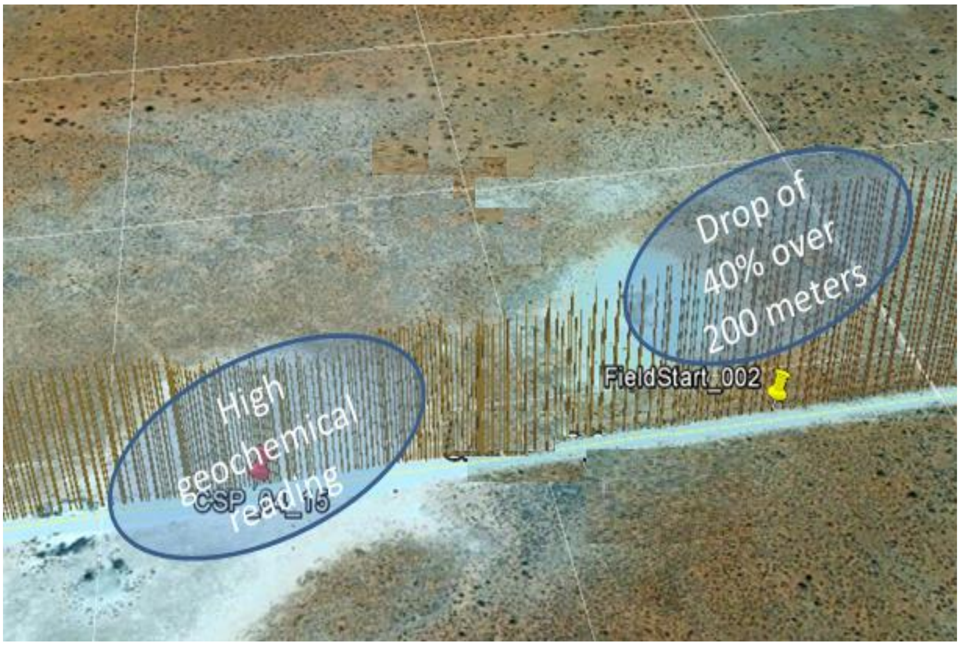
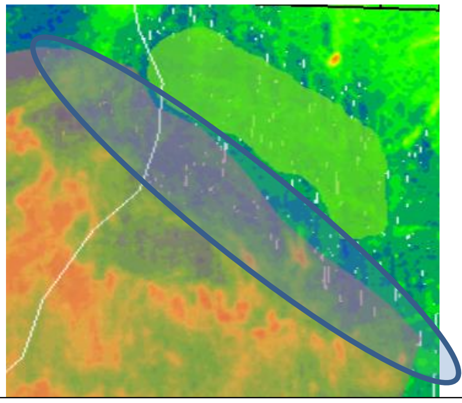


Figure 19 – Radiometric data visualisation on Google Earth. This vivid example was captured on the Taylor formation in 2219, which shows a dramatic drop in radiometric readings along with supportive paraffin microseepage.

The ground data will be cross referenced with airborne radiometric data purchased. See below for



The airborne radiometric data over the license area was collected primarily to assist with minerals exploration. The subtle changes in radiometric phenomena are largely masked by "noise" in the airborne data, while, larger mineralisation trends also mask the hydrocarbons trends. That said the blue ellipsoid highlighted is an area of interest where lower potassium 40 levels are supportive of the satellite evidence that suggests the edge of an oil field.

Figure 20 Airborne radiometric image layered with two satellite anomalies

Note that ground micromagnetics and ground Radiometrics will be collected concurrently and compared to airborne data. A detailed report on ANE's ground micromagnetics campaign will be included as an addendum in the next TAC report.

6.3. Geochemical Soil Sampling Program

6.3.1 Sampling objectives

The 123 geochemical samples analysed so far have shown sufficiently promising results for further exploration. Another 1,195 samples are to be being collected

The geochemical data collected to date shows that there are samples with significant levels of hydrocarbon microseepage, but, while promising, there is not sufficient data to draw conclusions. Therefore the company plans to collect of a further 1,195 samples to test the hypotheses which the focus on the Aminius, the Giant and Chapmans River.

38 hypotheses have been raised, where the sampling program is dividing into individual sub-campaigns that will collect sufficient evidence to prove or disprove them in a statistically robust manner. The objectives have be summarised into the following:

- Proving/disproving the hypotheses that
  - iodine and soil gasses can be discerned in three discretely different lognormal distributions
  - changes to vegetation and soils identifiable from satellite images within the visible range are correlated to the lognormal distribution into which the sample will – where a 70% accuracy in the prediction is targeted
  - Ethane composition indices and ethane/methane ratios enable different oil and gas pay zones to be separated – enabling the identification of different hydrocarbon signatures from different formations.
- Reduce the background, intermediate and significant results to a lognormal distribution formula for each dataset
- Find geochemical evidence f "Giant" satellite anomaly
- Mapping geochemical aureoles of significant microseepage outside the boundaries of the Aminius prospect
- Identifying and recording macroseepage of both oil and gas – four potential locations have been identified

Soil gas sampling will be compared to iodine and the existing C2-C4 acid test mapping used on the samples collected to date. Should the hypotheses be shown to be correct, the results can be extrapolated to 10s of millions of data points across the concession, using the satellite method tested. This would cost tens of millions of dollars to sample physically.

6.3.2 Sampling program

Due to budgetary constraints, only C_1 – C_4 paraffin levels and iodine levels will be measured in the first iteration. The first test will be over 50 salt pans across the license – with a focus around Aminius, where hydrocarbon seepage levels will be measured relative to the location relative to the centre of the salt pan.

Figure 21 Concentric sampling approach around Omongwa Salt Pan

The sample area illustrated in *Figure 21 Concentric sampling approach around Omongwa Salt Pan* is a 25 km^2 pan situated to 4km to the west of the tip of Aminius. It is located to the west of one of the most promising satellite High Quality Anomalies. It is seems evident that there is widespread cementation (calcrete deposition - greying of red clays) around the perimeter of the salt pan. The sparseness of vegetation in the area surrounding the pan also supports the notion that cementation has resulted in toxification of the soils, stunting floral growth. Samples will be taken from 17 points in and around the salt pan, providing information about relative levels of hydrocarbon seepage depending on their proximity to the centre of the pan.

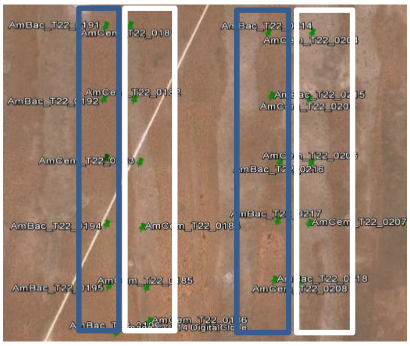


Figure 22 Transects comparing unaffected soils against those in the North-South dune lines where there is visual evidence of cementation

These north south trend lines (Transects) are situated about 30km North West of Aminius, again these are particularly interesting with their direction with which they run and their clear distinction between grey and brown soil, with a negligible change in altitude.

The key objective in collecting these two sets of samples (the concentric sample pan collections) such as those in Figure 22 Transects comparing unaffected soils against those in the North-South dune lines where there is visual evidence of cementation with the North South Transects will give sufficient data to isolate background, with intermediate and significant lognormal distributions, enabling the team to build a basin-wide geochemical database of paraffin levels.

As the license area is so large and indeed understanding hydrocarbon non-vertical seepage patterns across the larger Nama Basin are required, physical collection of a grid across 350,000 km^2 across private lands, outside the license area and indeed across political boundaries. Therefore the focus on soil sampling to prove trends where the physical sampling can largely be replaced by satellite analysis. This means that a stronger focus will be on creating a key whereby an analyst is able to use Google Earth to predict paraffin levels, with a follow-ups randomly selected test. This will enable vastly superior geochemical inference across the concession when compared to the complete radiometric, aeromagnetic and satellite datasets.

Note that the Gore Sorber 2nd iteration geochemical campaign will be described in detail, once the locations have been established. A top level description is offered in Addendum B.

6.4. Airborne data acquisition

6,000 line kilometres of airborne data are planned to be acquired, where full tensor gravity gradiometry will be augmented by airborne transient pulse, which ANE has used elsewhere in Southern Africa

Due to both the success of the spectral survey – where only 50% of the license area was eliminated, with over 3,800 km^2 medium and high quality anomalies, more airborne data is needed: Airborne gravity and aeromagnetic data has been acquired by the government and this has been purchased by ANE. While helpful, it does not give sufficient understanding of underground geometry in the way that seismic would.

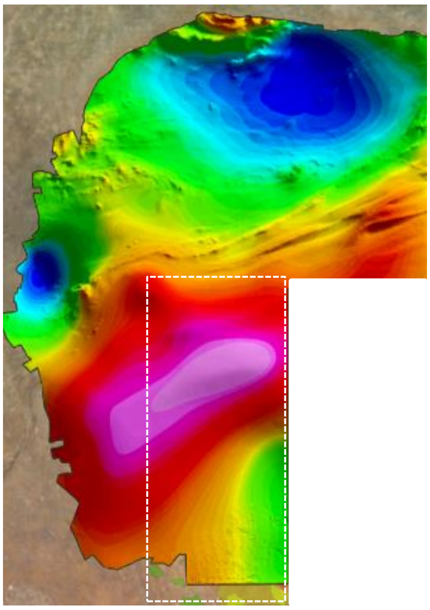
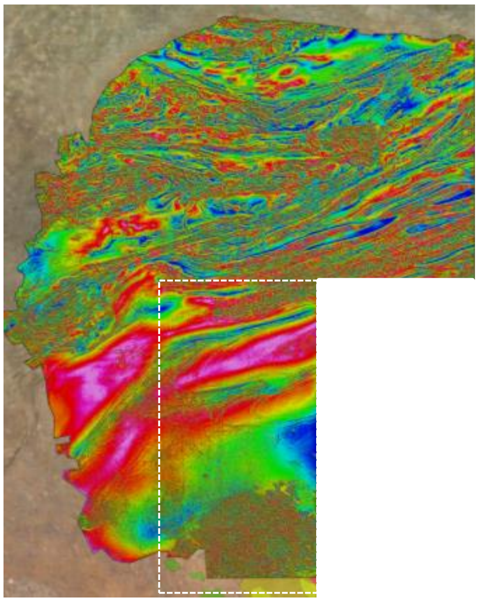
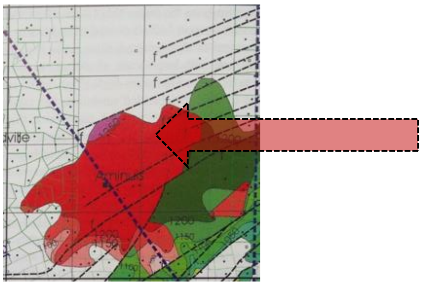
	

Figure 23 Pseudo gravity survey over Omaheke Province	Figure 24 Aeromagnetic survey – Tilt Derivative Filter applied

The board of ANE are of the opinion that the most cost effective solution to this problem lies in the combined use of Full Tensor Gravity Gradiometry, which provides lower resolution 3D imaging with transient pulse apparent resistivity depth survey in an airborne, which provides a direct hydrocarbons indicator in 3D. The advantage is that the data can be acquired on the same flight, sharing the aircraft overhead.



Example of basalts that will limit the effectiveness of seismic – the red in this picture signifies the elevation above sea level of the Kalkrand Basalt Formation.

Figure 25 the Kalkrand Basalt Formation over Aminius (Miller, 2008)

6.4.1 Full Tensor Gravity Gradiometry Survey

__Seismic will be difficult to acquire due to the basalts in the local area.__

Full Tensor Gravity Gradiometry (FTG) is fast becoming a recognized technology addressing the issue of basalts, pre-salt and sheer size. Gravity gradiometry is a measure of the differential acceleration of the earth's gravity field over a unit distance. It measures minute variations in the earth's gravitational field and therefore is a direct measure of the density distribution of the subsurface, enabling the low cost identification of structures and faults.

FTG has a particularly strong track record in East Africa, where the geology comprises relatively young sediments juxtaposed against a (much denser) Achaean basement, making it ideally suited to the use of this gravity exploration technique. While the Nama Basin hosts complex geology – this is particularly the case around Aminius – FTG's measurement of subtle variations in the Earth's gravity field to such a high degree of resolution that detailed basement structure maps can be derived which, in turn, allows for the optimal positioning of the ground tellurics campaign augmented by slim-well drilling.

The challenge of positioning tellurics blindly in an exploration license as large as PEL68, without seismic guidance is fraught with difficulty. Poorly positioned telluric stations may not image the geology optimally and potentially condemn a vast area as being non-prospective as happened with the seismic program and dry Masetlheng Pan 1 well in 1991. Being an airborne technique, an FTG survey can be acquired efficiently and rapidly over large areas and thereby focus future exploration budgets. The environmental footprint is also negligible.

Other advantages of deploying FTG include an improved definition of the sedimentary basin and internal architecture; and the identification of structural leads which can become a focus for tellurics and the slim-well drilling.

The earlier seismic shot elsewhere in the basin (INA, 2005, EU 1989) and the shallow well program could also be calibrated to the FTG and if necessary, the programme could be altered in places of shallow basement or insufficient depth of burial of potential source rocks. That said, the closest seismic is over 100 km from the boundary of the license, so the ability to integrate seismic into the existing program is remote.

Operators such as Tullow and Africa Oil have proven the effectiveness of FTG when they acquired FTG surveys over Kenyan, Ugandan and southern Ethiopian holdings to assist their exploration activities. The much publicized Ngamia-1 well in Kenya's Block 10BB was drilled on the back of an FTG survey within four years of the Block award.

Mozambican exploration activities have also had their share of attention following announcements from ENI and Anadarko of large gas discoveries. The Instituto Nacional de Petróle (INP), tasked with managing the country's oil & gas resources, has announced plans for a multi-client FTG campaign to build its exploration data portfolio, beginning with a planned survey over the Beira High.

Madagascar Oil has succeeded in finding over 1 billion barrels of oil using FTG, where they paid $130 per line kilometre with little in the way of mobilisation costs. This dramatically reduced their 2D seismic budget where mobilisation costs are $5 million with a variable cost of between $2k and $10k per line kilometre onshore will be incurred.

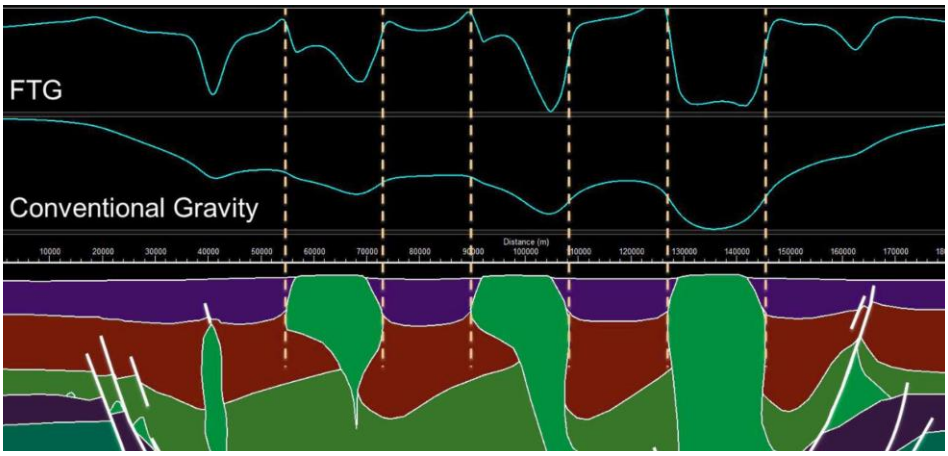


Figure 26 Enhancing Subsurface Understanding with FTG (Dodson, James, ARKeX, 2014)

6.4.1.1 Example of processing method – BellGeospace

Full Tensor Gravity has emerged recently to the stage where in conjunction with other technologies, it could be part of an exploration strategy that reduces or even obviates the need for seismic. The table below illustrates how Bell Geospace, the world leader, has developed its product over the last 15 years, where it is reducing the requirement for early stage 2D seismic – particularly over African onshore acreage.

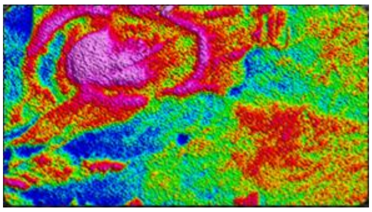
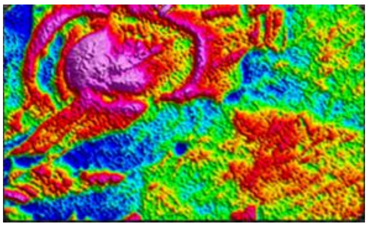
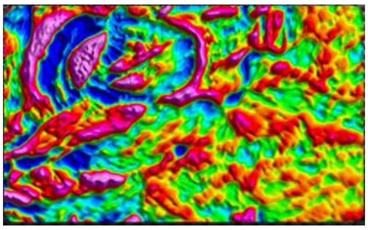
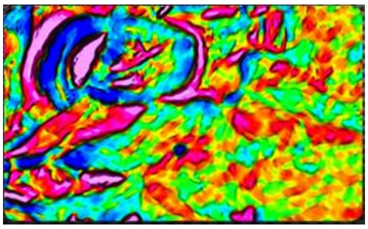
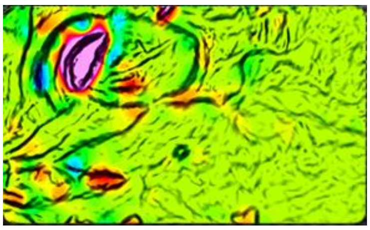
Image	Process description
	Levelled data - This shows an example of Gravity Gradiometry data after base level processing.
	Full Tensor Signal Enhancement – Each tensor component is used to component. The result is a high signal/noise ratio as shown in this example which has been base standard deliverable on Bell Geospace surveys since 2006. The benefit is more geological signal for interpretation.
	Residual data - Residual anomaly data captures the signature patterns from shallow, small scaled sub-surface ecology. The benefit is increased confidence when identifying and mapping target geology signature responses and their geological structural setting.
	Lineament Mapping - Interrogating the horizontal field components of the Gravity field identifies contact lineaments that occur between different stratigraphic units be they bedding, unconformity or faulted contacts. This example displays the contact lineaments on an image of a Gravity Residual field. The result is a Total Gravity field response used directly in geological layering.
	Target identification - FTG data is able map the gravity response of a target geological body. The resulting map captures the key response in each of the individual tensor component. Each target, be it high or low density, will be displayed as an isolated anomaly. The technique is used to map the presence of fault blocks – structural closures, ore bodies, salt, carbonate build-ups etc.

Figure 27 Full tensor gravity gradiometry technology progression

6.4.2 Transient pulse apparent resistivity depth survey

6.4.2.1 Scientific justification

Airborne Transient Pulse Surveys are the only airborne direct hydrocarbon indicator method that can give evidence of range of depth of hydrocarbons. It is possible to collect this data for less than $30 per square kilometre when flown in conjunction with the FTG.

As the FTG is captured using a light aircraft, the flight overhead can be leveraged with the addition of other data sources such as transient pulse. The transient pulse apparent resistivity depth survey technique is a direct hydrocarbon indicator (unlike seismic, aeromagnetics and gravity, which give insight as the geological geometry). Like seismic, it can be modelling in 3D using ANE's proprietary software.

ANE plans to use the apparent resistivity method developed by Pinemont Technologies Inc. This method measures phenomena first described in the AFMAG survey (Ward, 1959). Ward's was adapted to hydrocarbon exploration in the mid 1990's, when it was observed that - over non-depleted oil and gas fields - there exist a materially larger number of "Transient Pulses" than were found over their non-hydrocarbon producing counterparts. These electromagnetic pulses were found to contain packages of energy where the frequencies were within the audio range. These frequencies constituting the pulses are correlated to the depths from which they emanated. These pulses could be measured both on the ground and up to 300 hundred meters above the ground.

The key innovations of the patent awarded to John Jackson (US Patent Number 6,087,833) were: translating the relative strength of the audio transient pulse into digitised measurement whose logging could be automated - and corresponding depths to frequencies, enabling an initial 3D estimate of existence and depth of hydrocarbons. See below:

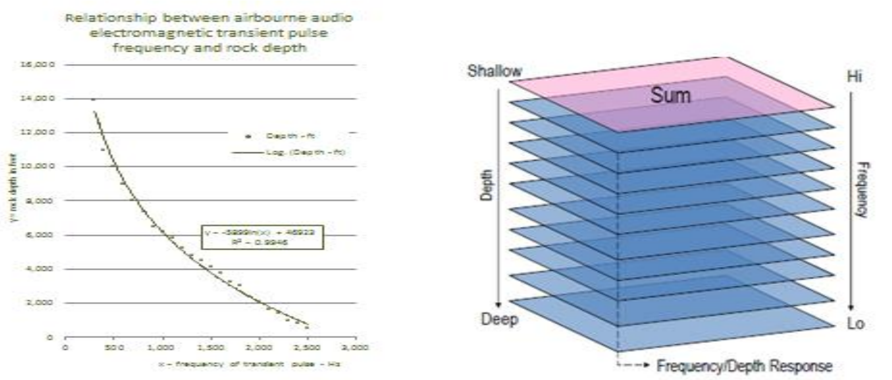


Figure 28 - the relationships between transient pulse frequency and hydrocarbon depth. Its results were validated over 130 known oil fields

ANE plans to collect the transient pulse survey data in while flying the full tensor gravity survey.

While the source of these electromagnetic fields is not well understood, it is thought to be related to naturally occurring seismoelectric streaming potentials resulting from micro passive seismic activity occurring worldwide. As passive seismic events occur, seismoelectric potentials and associated magnetic fields are energised at depth and then radiate to the surface. This phenomenon is described in *US Patent 5486764 - Method for determining subsurface electrical resistance using electroseismic measurements*. Regardless of source, Pinemont Technologies' method of measuring the electromagnetic fields is a breakthrough, both in terms of the compact nature of the equipment and the ability to collect field variations associated with hydrocarbon reservoirs at depth from airborne measurements. As the collected survey data is in standard ASCII format, it can be uploaded into ANE's proprietary software, contouring, and other geophysical programs to reduce risk associated with the estimation of hydrocarbon content at depth.

This survey is generally flown in a light plane (C172 Cessna in Limpopo) a at a height of 100m above ground level at slightly above a stall speed of 100 km per hour (LeSchack, Wyman, & Jackson, Surface Exploration Successful in Finding Alberta Leduc Pinnacle Reefs, 2004).

ANE's proprietary 3D visualisation software segments the Earths subsurface into ten sections down to a depth of greater than 15,000 ft (4,500 meters). The resulting data are presented in terms of relative signal strength for a designated segment of the subsurface. GPS, UT Time, Date and survey time are recorded simultaneously, making 2.5D modelling immediately possible, with 3D upgrading when calibrated with ground tellurics.

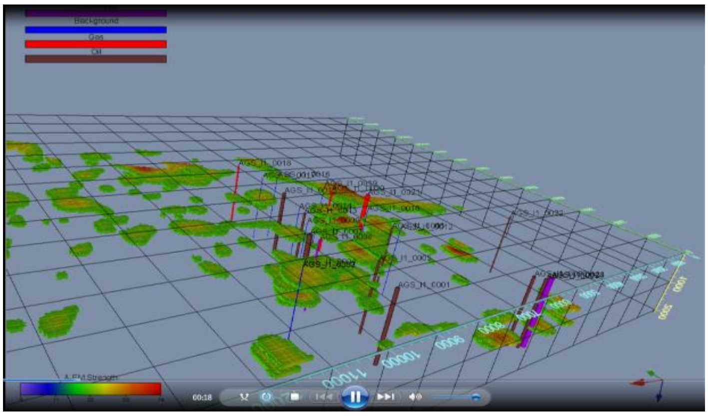


Figure 29 3D model of the airborne transient pulse data - showing anomalies over an associate company's EPL in South Africa.

Typically the area under investigation is covered by flying East-West flight lines spaced 1,000m apart. The on-board computer takes a reading every second and when data is processed at their lab, anomalous areas are shown as spikes rising above the flight line as illustrated below: This means that data points are available every 30 meters along the flight lines at stall speed.

Currently the wells are budgeted at 3,000 metres in depth. The airborne survey will give depth accuracy within 10%.

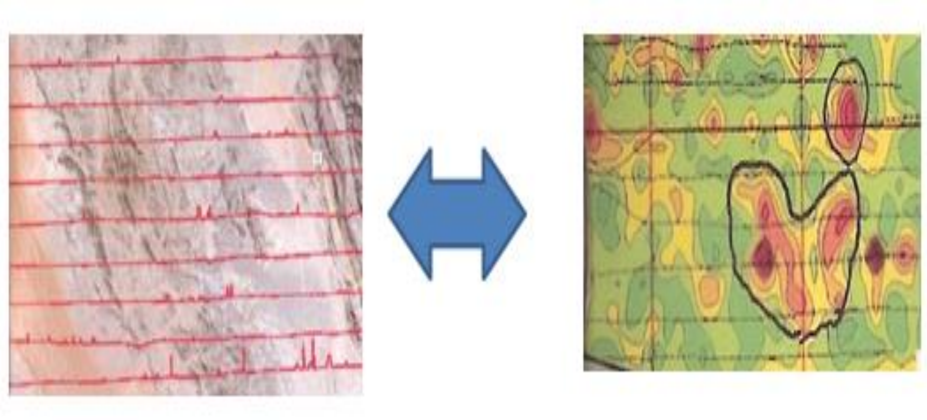


Figure 30 Translating transient pulse data into a more visually accessible map

Further processing integrates the Airborne Transient Pulse data, by using a Kriging algorithm that spatially analyses all the datapoints and the resultant channel layer map is illustrated in the right of *Figure 30 Translating transient pulse data into a more visually accessible map*

Transient pulse surveys offer the following key competitive advantages:

1. **Ease of interpreting the data –** the data can easily be transferred to the resultant channel layer maps that show up anomalous areas. 2 D seismic requires months of highly skilled interpretation of data and along with substantial IT overhead.
2. **Cost** – A 5,000 square kilometre area could in theory be covered within 12 flying days at a cost of $150,000. This translates to just $30 per square kilometre. This is 1/60th of the cost of 2D seismic, whose onshore variable cost ia a minimum of $2,000 per line kilometre.
3. **Success rate –** John Jackson, the holder to the patent has investigated the number of dry wells sunk, out of the over 130 exploration wells sunk as a result of transient pulse airborne surveys showing up positive anomalies. He has written a peer-reviewed

ANE and its associates have performed three airborne tellurics surveys in Southern Africa and has created 3D software to visualise the results and compare them to other surface tests such as radiometric and geochemical.

case study for the Association of American Petroleum Engineers (AAPG) showing an 80% success rate. (LeSchack, Jackson, Dirstein, Ghazar, & Ionkina, 2010). 2D seismic, the incumbent technology has a probability of just 15% where it finds positive anomalies and is not well suited to subtle stratigraphic traps that make up 40% of US conventional production or removing noise from basalts that are prevalent on the License Area.

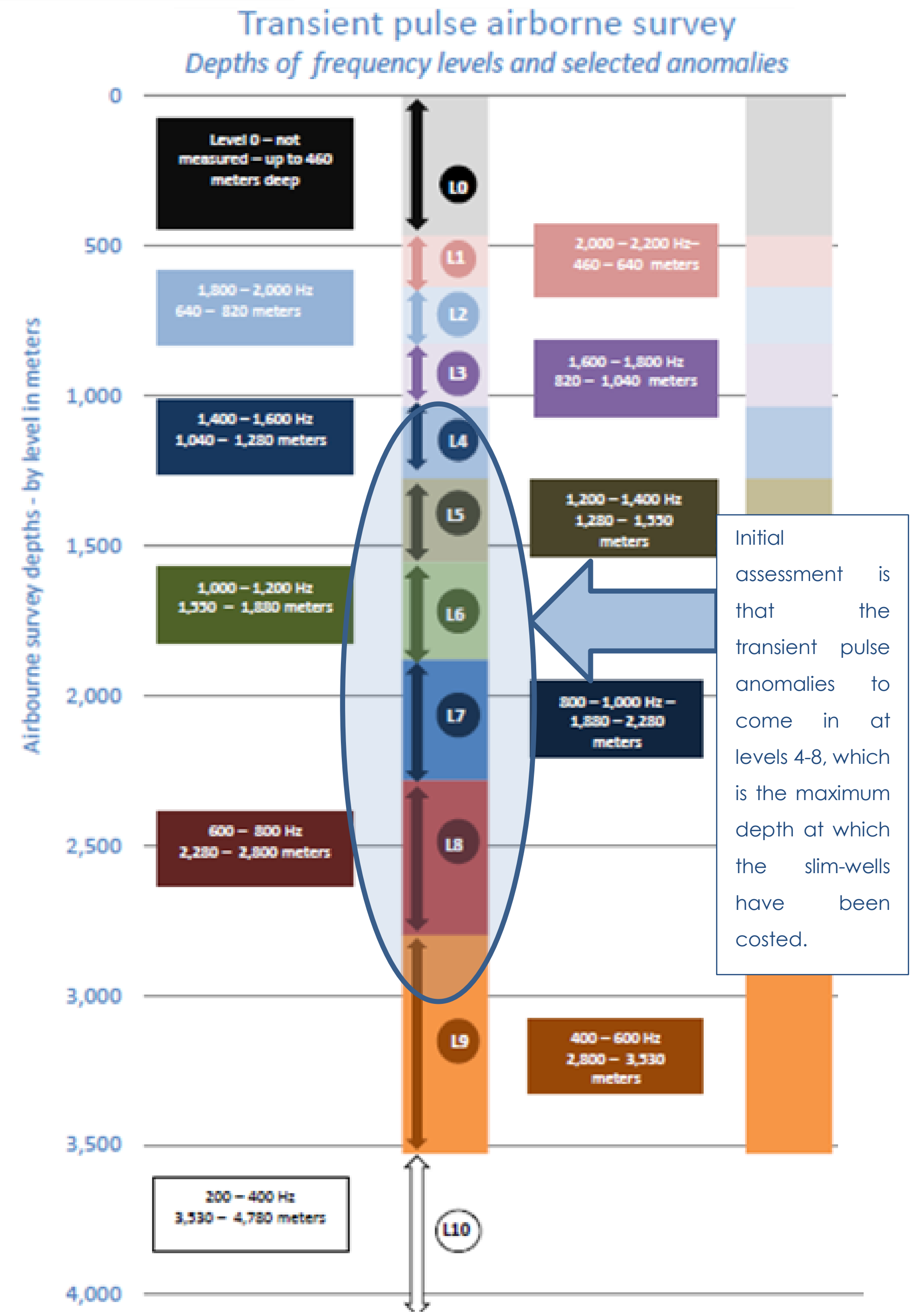


Figure 31 Airborne survey levels vs. depths

ANE's associates have performed two transient pulse surveys in Southern Africa, while bespoke software has been written to visualise the results in 3D

Three of these surveys have been performed by LeSchack and Pinemont– over South Namibia, Alumni Limpopo and Riverwalk. The findings were translated into a 3D model by Raw with the assistance of Harrison – see below in *Figure 32 2D model of the transient pulse data - showing anomalies over the Alumni Limpopo EPL, which were used to pinpoint locations for further radiometric, geochemical, and ground telluric acquisition.*

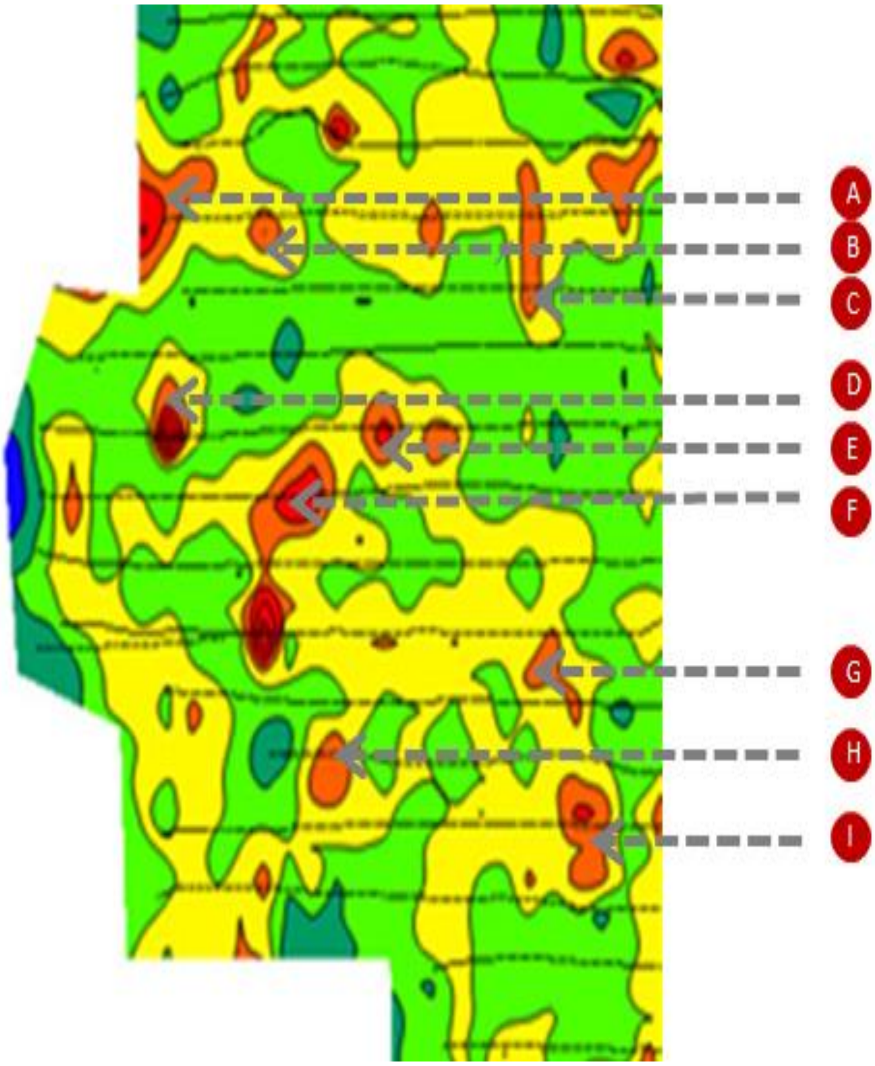


Figure 32 2D model of the transient pulse data - showing anomalies over the Alumni Limpopo EPL, which were used to pinpoint locations for further radiometric, geochemical, and ground telluric acquisition.

The passive tellurics is complimentary to the FTG airborne data, as they provide a 3D evidence from a direct hydrocarbon indicator.

6.5. Tellurics ground-truthing program

The on-ground tellurics program captures similar data to the airborne transient pulse, but is adds magneto telluric with rador to improve effectiveness and increase granularity: The airborne survey gives a depth resolution of 200-300 meters, while the on-ground tellurics gives a resolution of eight times that, as the former collects data at 200 Hertz intervals, while the latter collects it at 25 Hertz frequencies, which improves understanding of depth by a factor of 8. At the 2,200 Hertz level (464 meters) the resolution is improved from 170 meters to 21 meters. See below:

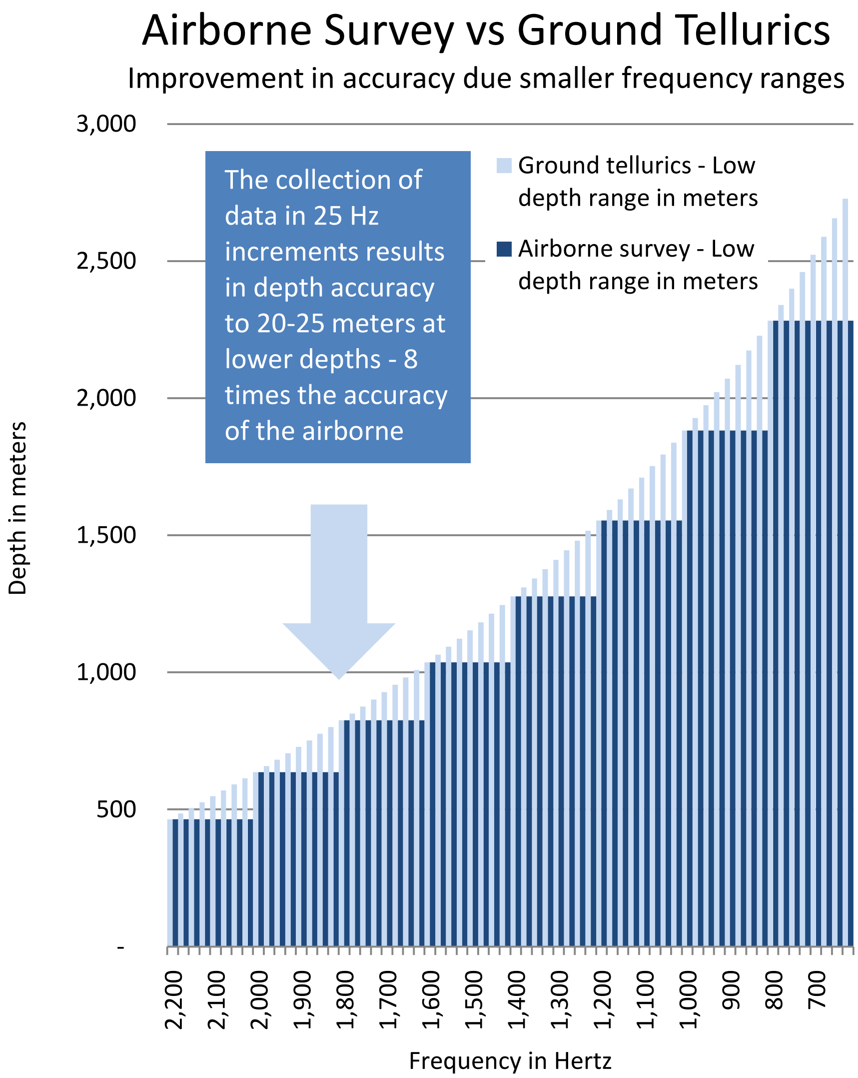


Figure 33 Reducing frequency ranges from 200 Hz to 25 Hz improves depth resolution by 8 fold

Woods estimates that DMT's acoustic log can

The ground tellurics service will be provided by DMT, whose most experienced operators are Bob Meconis and Dan Woods, who claim 15 discoveries in frontier areas in the Mid Western United States.

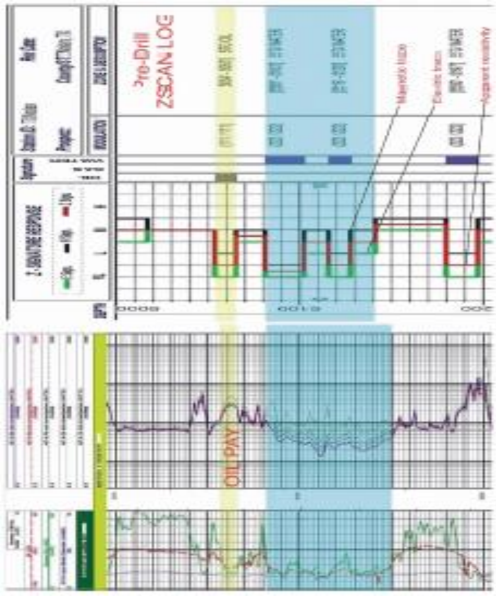


Figure 34 Example of a tellurics log using DMT's Z-Scan acoustic analysis process

The following campaign has been planned:

	Km^2	Payzone stations 1,500ft	Stations per day	Days in field	Field work day fees – $'000s	Analysis costs "Main Station" - $'000s	Analysis costs - "Payzone Stations" - $'000s
Aminuis	300	50	5	13	65	24	150
Taylor	500	50	5	13	65	24	150
The Giant	1,200	50	5	14	70	24	150
Total	**1,800**	**150**	**5**	**40**	**200**	**72**	**450**

Ground tellurics	Input	Comments
Number of anomalies - pre-drilling	3	Aminuis, "The Giant" and Taylor
Cost per foot of reading in US$	2	Source Dan Woods
Average depth per reading in feet	12,000	Could change, but worse case scenario
Analysis cost per main station in USD	24,000	12,000 ft X $2 per foot
Expected payzone reading in ft	1,500	Assumes extenstive payzone
Cost per "Payzone Station" in USD	3,000	1,500ft X $2 per foot
Cost per tellurics operative - per day	5,000	Skills too specialised to train locals

Figure 35 Costing of ground tellurics

7. Stratigraphic drilling program

7.1. The benefits local contractor drilled thin wells

The use of local contractors will reduce the cost of drilling from $18 million quoted by an international oil services company to $3 million.

If an area is found, where all tests show – independently that a positive anomaly has been found, then the project will move from the exploratory to the drilling phase, where a drilling license will be applied for. If none of the areas come back positive, Alumni will inform the ministry and the licenses will not be renewed.

Southern Africa does not have any on-shore oil drilling rigs and it is estimated that it would cost $8 million in transport charges to transport one South Africa. What Southern Africa does have, is one of the world's most advanced mining sectors and Alumni's exploration partners tap into this expertise to drill exploratory wells at a low cost. A three-inch core can be drilled for half the cost that a 6 inch exploratory well could be drilled for – and the rig transport costs are avoided at the high-risk exploration stage.

The drilling company is an experienced contractor in the South African mining sector has agreed to sink seven exploratory wells that will be needed to prove the reserve, extent of the reserve and flow rates can be assessed using a Kriging algorithm.

The drilling company is an experienced contractor in the South African mining sector has agreed to sink three exploratory wells that will be needed to prove the reserve, where extent of the reserve and flow rates n be assessed using a Kriging algorithm.

Two listed Southern African mining service providers have quoted for the job to drill 3' diamond core slim wells

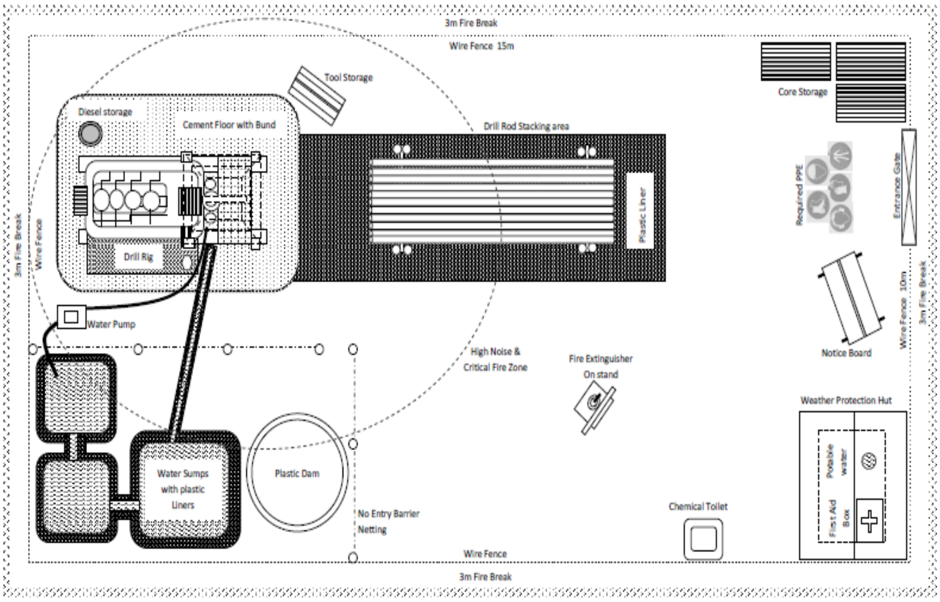


Figure 36 Drill rig plan

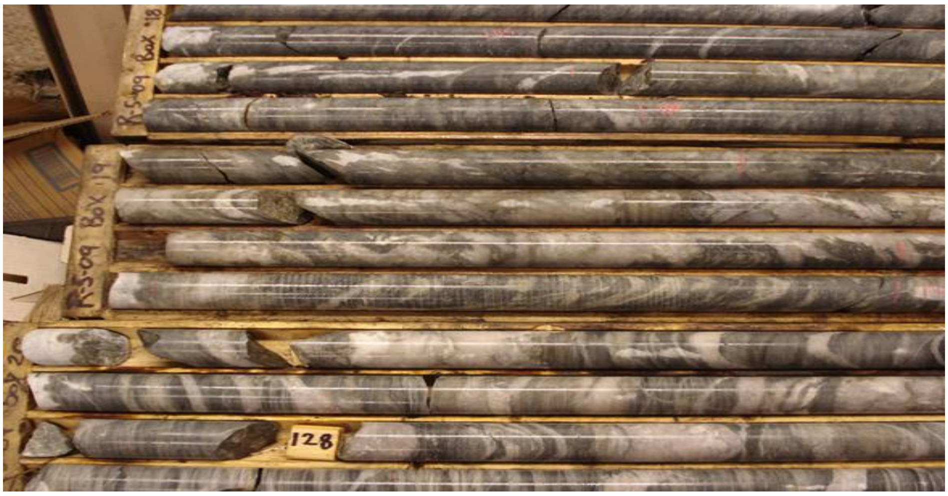


Figure 37 Drill cores

The use of drill-cores are regarded as the most effective method of obtaining an understanding of an exploratory well, but due to their expense compared to standard drilling – are seldom used. The presence of a highly competitive local mining industry means that Alumni will be able to avoid the multi-million dollar cost of transporting a rig, and will be able to use three inch wells to extract cores which can be analysed in laboratory conditions – at the cost of the lowest traditional exploration drilling cost in the USA. Seven exploratory wells are planned.

7.2. Drilling plan

Certainty as to the existence of hydrocarbons can only be established once the rock has been drilled. There is currently a global shortage of drilling rigs and the wait for rigs can be as long as four years. Alumni has the following drilling strategy that reduces the cost of mobilisation in both failure and success.

- **1st iteration 3 inch core drilling and second iteration 4.5 inch reaming–** using local mining drilling service companies for initial drilling, give three key benefits:
    - **Negligible rig transport, mobilisation and demobilisation costs** - measured in tens of thousands compared to the cost of importing a drilling rig from the USA estimated to be \$8m (in addition there is a shortage in Africa).
    - **Development of a core library** – the three inch cores provide superior geological data to traditional mud-drilling;
    - **Reduced pre-discovery costs –** should the 3-inche wells show hydrocarbons, the well can subsequently reamed to 4.5 inches on which drill stem testing can be performed thus reducing dry-well drilling costs by 40%.

In summary the surface exploration techniques pioneered by the Alumni team in North America and Southern Africa improves the pre-drilling probability of commercial discovery from less than 40% to over 80% - and does so at 1/30th of the cost of 3D seismic. The drilling strategy result will result in a 1,500 meter dry-well cost being \$50 per foot with the 4.5 inch reamed well with a drill stem test coming in at \$85 per foot. Texas drill rig costs are \$150 per foot for a dry hole.

7.2.1 Three inch exploratory wells

Of the nine anomalies identified, the exploration program assumes that two will fail the further radiometric and on ground tellurics tests, leaving seven sites to be selected for exploratory drilling. Alumni's approach materially reduces the financial exposure as there are no delays and

By splitting the 3 inch and 4.5 inch reaming process dry well costs are reduced by 40%.

transport costs to move the rig to the site, as local mining services rather than oil services companies are being used.

It is assumed that the seven deepest anomalies will be selected and a contingency of 10% is included on the depth of drilling calculation.

7.2.2 Four-and-a-half- inch appraisal wells

It is expected that two of the seven exploratory wells will fail – this could be because of engineering difficulties such as drill bits breaking or because of the geological team assessing that the wells require no further investigation – due to poor commercial prospects.

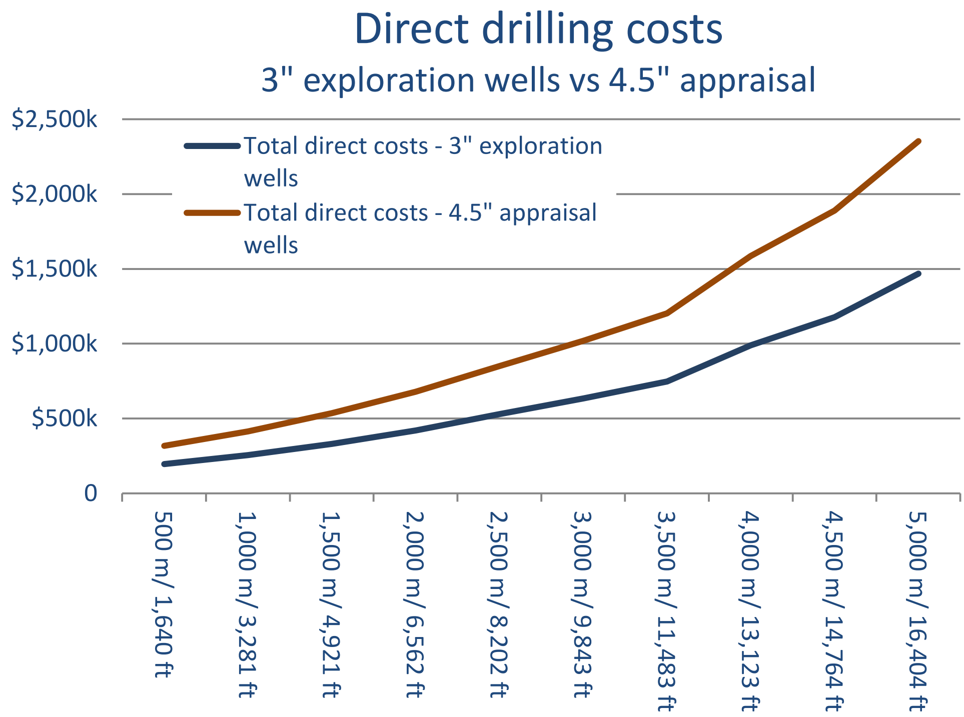


Figure 38 Cost of 4.5 inch reaming vs. 3 inch exploratory holes

The cost of drilling is 60% of the variable cost of exploratory drilling. This is effectively a 30% contingency.

7.2.3 External appraisal of reserves

7.2.3.1 Wireline tests

As the deep level three-inch diamond core drilling enables the evaluation team to evaluate the porosity, permeability and geological formation of the rock, the cost of well testing is minimized, when compared to traditional mud-based percussive drilling. The focus of ANE's testing will

Despite the slim wells being 3 inches, drill-stem tests and casing will not require modified equipment, enable flow rates and pressures to be measured without conventional drilling rigs being required.

revolve around a wireline tests where no bespoke engineering work will be needed as 1 7/8 inch diameter drill stems are available:

The drill stem test is effectively a temporary completion of the well at the fraction of the cost of completion: As the well is drilled, the combination of the drilling mud and the blow-out preventer keeps the fluids back in the pores of the rock adjacent to the wellbore. If the cores indicate the potential reservoir, a drill stem test can be run to further evaluate that reservoir. A drill stem which consists of:

- a drill string of drill piping is run in the well
- perforated pipe
- pressure gauges
- a valve assembly
- one or two packers

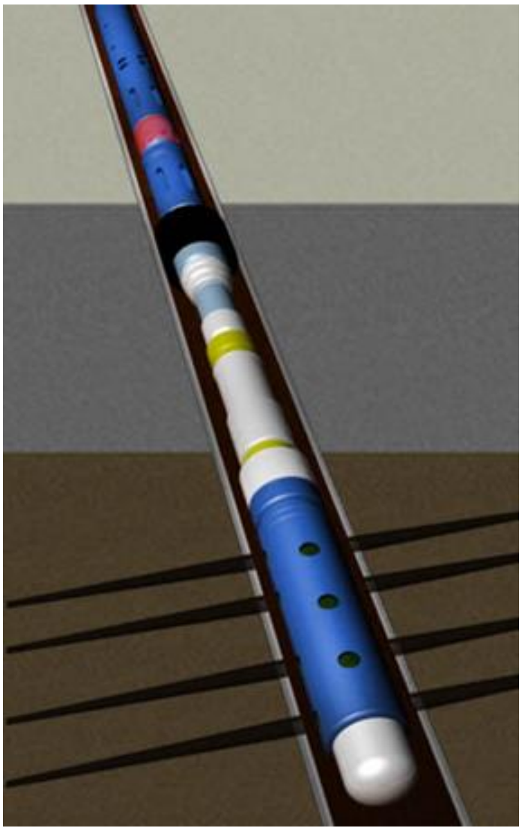


Figure 39 Example of a drill stem

Packers are cylinders made of a rubber-like material that can be compressed to expand against the well walls to seal that portion of the well. The packers prevent any vertical flow of fluid in that section of the well. If the formation is located on the bottom of the well, only the packer is used. If the formation is located above the bottom of the well, two packers (straddle packers) are used.

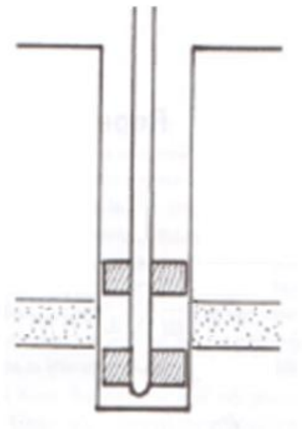


Figure 40 Straddled packers

ANE's use of local mining companies to provide drilling services, reduces transport costs from $8 million to $216k.

The packers eliminate the drilling mud pressure on that formation. After the packers have been seated, then water, gas or oil can then flow out of the formation and into the well. A valve is opened on the drill stem, and the formation fluids flow into and up the drill stem. If gas is present, it will flow up the drill stem and onto the surface where it is measured and flared. Sometimes oil has enough pressure to flow to the surface during a drill stem test. Usually however, the oil fills the drill stem only to a certain height that is measured. The initial pressure is highly correlated with depth of this type of FDD reserve, as the following study shows:

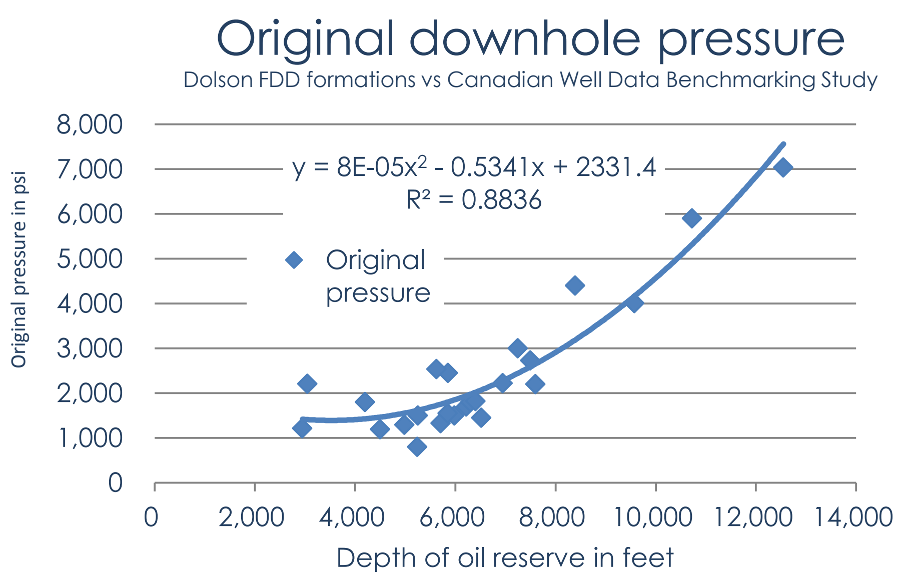


Figure 41 Relationship between pressure and well depth for FDD oil formations (Dolson, 1984)

8. Risk identification and management

8.1. Key risks

This is a high risk project as the technology is not conventional, the region is frontier and the management team is new, despite certain members of the team having a proven track record in finding oil

Oil exploration is by nature high risk, and less than 10% of wildcat wells drilled in frontier basins resulting in commercial hydrocarbon discoveries. It costs the average oil company $17 to find a barrel of oil. Under this program, if ANE succeeds in making a discovery within this budget, depending of the size the cost per barrel of oil discovered could be between 10 USc and $1.00.

8.2. Exploration risks on a frontier region

Six out of seven barrels ever found have been found close to existing oil fields. Finding oil and natural gas in frontier areas, defined as areas where hydrocarbons have never been found before, is more difficult, as there is little knowledge of the local geology.

8.3. Technology risks using new(ish) exploration techniques

Why traditional seismic techniques are unlikely to work on the Alumni East Namibia concession

The seismic industry has grown to a $10 billion a year oil services industry. It has certainly improved the discovery rate in an industry with notoriously high proportions of dry wells, where seismic improved from 20% to an average of 42%. (Schumacher 2010). The avoidance of use of seismic, is a fundamental departure from traditional techniques: Seismic is unlikely to find this oil for the following reasons:

- **Interference of igneous rock** – seismic is enable to penetrate igneous rock and basaltic intrusions, which are common in the area: The potential hydrocarbon-bearing sediments are sometimes below and in close proximity of the Bushvelt Igneous Complex, making acquisition of seismic impossible in several areas
- **Lack of structural traps** – Seismic gives valuable information about faults and structures that make for effective traps. These thin river channels can be as thin as eight feet thousands of feet below the surface and are trapped by pinch-outs between non-porous rocks, rather than traditional traps from domes and faults.

- **Unable to differentiate between brine and oil –** seismic only provides information about rock structure, and finds suitable potential traps that *could* host hydrocarbons. More often than not, seismic traps host brine (salty water). Alumni's techniques use surface evidence to locate oil beneath.

The inability to use seismic as the primary exploration method, will reduce ANE's ability to attract funding and industry partners.

The surface exploration methodology is adopted by ANE has resulted in a number of successes in frontier areas using several of these technologies. The techniques themselves have all been proven in the field in North America for at least fifteen years and - working in isolation - have an extensive track record.

These techniques have been subject to academic review and have shown to be successful in North America. They have never been proven to work in Southern Africa – where – indeed no onshore oil has ever been found in commercial quantities using any exploration techniques. This means that unknown regional variations could result in misleading indications – particularly with the airborne survey, which is subject to minimal academic peer review anywhere.

The surface exploration techniques are all collecting evidence from the same underlying phenomenon – that microseepage can be detected through data collection, where their presence affects radiometric elements, hydrocarbon gasses can be present and the hydrocarbons give off microelectric pulses than can be picked up with a sensitive antenna.

This means that occurrence of all surface evidence is strongly correlated, meaning that chances of discovery pre-drilling will never be higher than 85%.

Not enough scientific review has been done to ascertain any probability of discovery from the airborne survey. It is however effective in calculating maximum depth and showing the absence of hydrocarbons.

8.4. Risks around the Airborne Survey

The investor of the airborne survey, John Jackson, studied 100 existing oil fields in the United States and showed that 85% showed positive anomalies from his airborne survey techniques. This data has not been subject to academic review there are several weaknesses with the hardware and software:

- Key variables are not collected. This can result in the same flight path being flown on different days delivering fundamentally different data;
- Kriging techniques need to be adapted for different geological circumstances based on the subjective view of the geologist interpreting the data.
- Tellurics are not well understood and not enough data has been collected to understand regional variations in the way that electromagnetic regional variations are understood.
- The airborne survey does not give exact location of hydrocarbon anomalies rather indications of the general area. No estimates can be made of the extent of gross rock volumes nor can any assumptions be made as to the extent of potential anomalies;
- Not enough scientific review has been done to ascertain any probability of discovery from the airborne survey.

9. Organisation and people

9.1. Organisational structure

The team includes industry veterans with an impressive track record in discovering oil, a strong board and excellent local skills, balanced with finance, legal and IT skills.

The Alumni management team combines the right of local leadership, engineering and geology and geophysics skills need to find hydrocarbons in a frontier zone. More importantly, the group combines to form the world's leading hydrocarbons surface technologies explorations team.

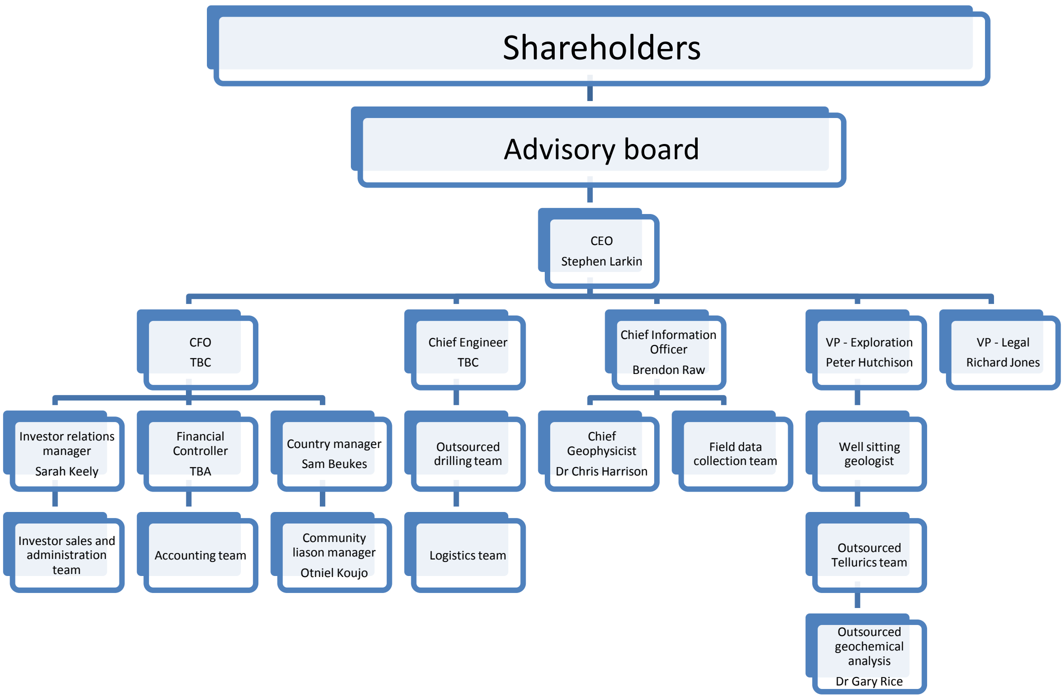


Figure 42 Organogram of ANE

The CEO and Founder, Christo Smit reports to the advisory board, which will comprise a majority of non-executive directors as well as a non-executive chairman in keeping with corporate governance best practice.

9.2. Key members of the management and technical teams

CEO – Stephen Larkin –is a London-based chartered accountant, who has run a mine technology company working in the local area. He has got three start-ups funded.

ANE technical team have made multiple discoveries in their collective careers, which combine to over 2 centuries of experience.

CTO - Brendon Raw– an energy IT specialist, who ran BP's front office systems for five years. A successful technology investor, he seed-funded Africa's leading e-marketing company (Quirk) and has also developed the world's cheapest solar monitoring system.

VP Exploration – Peter Hutchinson – created Scotforth in 1996 with two Russian partners. They have since done 35 surveys and have a 70%-80% success rate, where their anomalies have been drilled upon, while drilling on negative satellite anomalies results in a 10% success rate

Legal director – Richard Jones – former head of legal of BP Upstream, BP's first Russia Manager and legal advisor to two of AIM's best performers – Nautical Petroleum and Quadrise

Namibia country manager – Sam Beukes - is the former CEO of the state owned oil company NamCor, and is arguably the most experienced oil executive in Namibia.

Geochemical analyst – Dr Gary Rice – regarded as one of the world's leading experts of geochemical analysis of hydrocarbons. His contribution is vital as the investor will be 80% certain of commercial discovery before investing, thanks to Dr Rice's analysis.

Geophysicist – Dr Chris Harrison – has a geophysics PhD from Calgary University and has written software to interpret raw airborne survey data, working on conjunction with Leonard LeSchack

Tellurics analyst – Bob Macionis – an MSc from Bowling State with 14 years' experience in tellurics and audio magnetotelluric technologies, ranging throughout the United States, Canada, and Sultanate of Oman. Bob's work has led to several oil field discoveries in Kansas and Michigan.

The management and technical team profiles are given in more detail in Addendum C.

10. Stakeholder engagement

10.1. Local shareholders

The company has allocated 8% of its shares to local partners, who include youth, community experts and the former Managing Director of the host country's state owned oil company.

The government recommends that 10% of the shares in entity holding the exclusive prospecting license are held by local Black Economic Empowerment qualified persons. ANE has an agreement with the following four BEE persons, who have been allocated shares in the UK holding company, rather than the local company.

- Sam Beukes – former CEO of NamCor, who is contractually bound to receive 3.5% of the shares in Alumni Exploration East Africa (Pty) Ltd. He is the country manager for ANE.
- Lazarus Shiimi, a youth leader and musician, who is better known by his stage name "Gazza", a youth ambassador who is contractually bound to receive 2% of the shares in Alumni Exploration East Africa (Pty) Ltd.
- Otniel Koujo and Katjimuna Tjozogoro, who are mining entrepreneurs who co-own a company called Great Kunene, which has been awarded an impressive number of mining and oil and gas concessions in Namibia. Koujo is a former marine diver for CDM and Tjozogoro is trained in IT. They both hail from the local area and have proven resourceful in developing community relations as well as collecting radiometric and geochemical data. They have been awarded 2.5% of the shares in ANE.

Although no shares have yet been allocated, the company plans to include Immanuel Ambata as a local shareholder. He has managed the data collection in the field with skill and dedication and it is intended that he be further incentivised when he does become a shareholder.

It is the company's aim for the local team working on the project to receive 8% of the Pre-Series C share capital.

10.2. Community Trust

The founders of the company, Brendon Raw and Stephen Larkin are currently majority shareholders in ANE. They have pledged that 9 million shares will be allocated to a community trust that will focus on the needs of the Herero, Nama and San people who live on the license area.

These shares will be allocated from Raw and Larkin's current holdings rather than diluting shareholders. The co-founders believe in that the company has benefitted from the assistance from the community, where they have been generous with their support and also their encyclopaedic knowledge of the local terrain.

The co-founders, Brendon Raw and Stephen Larkin have pledged 9 million shares (10% of the founding share capital) to a Trust that will benefit the local community

The incident described below illustrates the importance of embracing the local community. The lady with whom the author is photographed tells of excitement outside her house in 1986, when the South Africans were drilling a water well. At 45 meters, they detected oil. As South Africa was in the throes of losing control of Namibia and sanctions made it impossible to explore in Namibia at the time, this vital information was never captured. In November 2013, she told Stephen Larkin, where the water well was and the team took soil samples, which showed significant microseepage with paraffin levels 100 times the expected background. ANE's work

10.3. Community Projects Planned - Permaculture Project

ANE's first community project is a permaculture project that aims to develop water efficient vegetable farming skills, so improve dietary balance amongst the local community

ANE has started with its community commitments in the form of a permaculture project on the land of the late Paramount Chief of the Herero, Kuaima Riruako, whose land is located on Block 2219. The project aims to develop water efficient vegetable farming skills, so improve dietary balance amongst the local population.

Figure 43 ANE's Permaculture project on 2219

The project was launched in response to the worst drought in two decades, where the fostering of wetter micro-climates increases rainfall. The company also plans to use its geological and solar skills to find artesian water supplies and to use solar to pump close-to-surface water

Figure 44 Building berms from dead wood to provide nutrients for the permaculture project

10.4. Use of training and development levies

The company has paid a total of $82,000 to the Petro Training Fund and has committed a further $18,000 per annum towards development of local skills within the hydrocarbons exploration sector.

The company takes local empowerment seriously and has not only provided training to its local team to perform the soil gas sampling, but also data collection using the radiometric equipment. Furthermore, the company plans to train people on the concession to provide micromagnetic data collection services and to be involved in the airborne surveying as well as the vital ground tellurics program.

The company has outsourced all ground data collection to local contractors

ANE has a unique opportunity to unique opportunity to involve local people, as the skills it requires are not mainstream and therefore training will be required, whoever provides them. The company has committed to give priority to people in the local communities preference with jobs and skills provision.

Highly resourceful members of the local community, such as Katjimuna Tjozogoro (pictured) have been trained in ANE's new techniques of data collections. The capturing soil gas samples using a probe helps the company to understand the levels of Paraffins in the soils. ANE's innovation in the area of geochemistry involves using a combination of soil gas samples with iodine – a reliable indicator of hydrocarbons, cross referencing it with satellite images, with ground truthing using this probe. In combination with in house developed software we are able to create tens of millions of data points, ground truthing them.

Figure 45 ANE's first training project - geochemistry soil gas sample collection

The company is required by Namibian the Petroleum Act of 1991 to minimize the impact its activities have on the environment and to report frequently as per best oil field practices within the international industry.

10.5. Environmental law compliance and management

10.5.1 Environmental commitments make in the EPL application

The company is required by Namibian the Petroleum Act of 1991 to minimize the impact its activities have on the environment: As is required by the Act, the company has committed to conduct its operations in terms of the Petroleum agreement to be entered into with the Minister of Mines and Energy, and according to Sec 77.1 of the Act (*1998 MA Clause 11.2, 11.13, - 1991 PA Sec 77. 1)*.

In the EPL application submitted in December 2011 the company has committed to;

- Conduct its operations in a manner likely to promote the conservation of Namibia's natural resources and protection of its environment;
- Employ the most advanced techniques for the prevention of environmental damage to which its petroleum operations might contribute and for the minimisation of the effect of such operations on neighbouring or adjoining exploration licences;
- Implement the proposals contained in its development plan regarding the prevention of pollution, the treatment of wastes, the safeguarding of natural resources and the progressive reclamation and rehabilitation of lands disturbed by petroleum production.
- Prevent the pollution of all areas of water by the spilling of petroleum, drilling fluid, chemical additive, any gas or any waste product or effluent;
- Furnish to the Commissioner prior to the drilling of any well a report containing particulars of the technique to be employed, an estimate of the time to be taken, the material to be used and the safety measures to be employed in the drilling of such well
- Not flare any combustible gas, except: for purposes of testing such gas, or for operational reasons.

10.5.2 Proposed Environmental Impact Assessment

An environmental impact assessment will be needed before the drilling commences. As it is away from national parks on largely uninhabited land, impact is likely to be small.

The constitutionality of the environmental regulatory framework in Namibia is based on the Article 95 of the Constitution of the Republic of Namibia (1990), which states that; "*the State shall actively promote and maintain the welfare of the people by adopting, inter alia, policies aimed at maintenance of ecosystems, essential ecological processes and biological diversity of Namibia and utilisation of natural resources on a sustainable basis for the benefit of all Namibians both present and future*" Article 101 further states that; "*the principles embodied within the constitution shall not of and by themselves be legally enforceable by any court, but shall nevertheless guide the Government in making and applying laws*." The courts are entitled to have regard to the said principles in interpreting any laws based on them.

The most important pieces of legislations with respect to the proposed project are those covering mining, environment and water.

Currently, the Environmental Assessment (EA) process in Namibia is governed by the Cabinet approved Environmental Assessment Policy for Sustainable Development and Environmental Conservation of 1995 published by the Ministry of Environment and Tourism (Directorate of Environmental Affairs (DEA), 1995). On page 19 is a diagram showing all the relevant stages that are required in an environmental assessment process.

The Environmental Assessment (EA) procedure as outlined in the Environmental Assessment Policy for Sustainable Development and Environmental Conservation (1995), set out to:

(i) Better inform decision makers and promote accountability for decisions taken;

(ii) Consider broad range of options and alternatives when addressing specific policies, programmes and projects;

(iii) Strive for a high degree of public participation and involvement by all sectors of the Namibian community in the EA process;

(iv) Take into account the environmental costs and benefits of proposed policies, programmes and projects;

A large body of legislation and policy needs to be considered. This is to be welcomed as regulation is well defined providing certainty as to environmental responsibilities.

(v) Incorporate internationally accepted norms and standards where appropriate to Namibia;

(vi) Take into account the secondary and cumulative environmental impacts of policies, programmes and projects;

(vii) Ensure that the EA procedure is paid for by the proponent. In certain cases, such as programmes initiated by the State, it is recognised that the Government is the proponent and will meet the costs of an independent EA;

(viii) Promote sustainable development in Namibia, and especially ensure that a reasonable attempt is made to minimise anticipated negative impacts and maximise the benefits of all developments;

(ix) Be flexible and dynamic, thereby adapting as new issues, information and techniques become available.

The Environmental Management Act of (2008), administered by the Directorate of Environmental Affairs, Ministry of Environment and Tourism is aimed at giving statutory effect to the Environmental Assessment Policy for Sustainable Development and Environmental Conservation (1995). The purpose of this Act is to give effect to Articles 95(c) and 95(1) of the Namibian Constitution by establishing general principles for the management of the environment and natural resources. It further promotes the coordination and integrated management of the environment. Schedule 1 of the Act lists activities that require a full environmental assessment to be conducted and include exploration and mining related.

10.5.1 Body of legislation and policy that affects the license rights

The following are some of the relevant legislation and policy strategies with respect to the proposed exploration project and possible drilling in blocks 2219 & 2319;

10.5.1.1 Legislation

- Prospecting and Mining Act, 1992, (Act No 33 of 1992);
- Water Resources Management Act, 2004, (Act No. 24 of 2004);

- Hazardous Substances Ordinance 14 of 1974;
- Atmospheric Pollution Prevention Ordinance 11 of 1976;
- The Nature Conservation Ordinance, Ordinance 4 of 1975,
- Amendment Act, Act 5 of 1996 and the current draft Parks and Wildlife
- Management Bill of 2006;
- The Regional Councils Act, 1992, (Act 22 of 1992);
- The Local Authorities Act, 1992, (Act 23 of 1992);
- The Labour Act 2004, (Act 15 of 2004);
- Petroleum (Exploration and Production) Act 1991 (Act 2 of 1991);

10.5.1.2 Policies

General

- Namibia's Green Plan;
- Vision 2030;
- Regional Development Strategy;

Environmental Management;

- Namibia's 12 Point Plan for Integrated and Sustainable Environmental Management;

Water

- National Water Policy White Paper 2000;
- Water and Sanitation Policy;
- Integrated Water Resource Management and Water Demand Management Policy;

10.5.2 How ANE's surface exploration techniques minimize environmental impact

ANE's approach has less impact than traditional exploration companies as it avoids using seismic except in certain circumstances close to the well. The use of horizontal drilling to follow shallow meandering channel sands will minimize the environmental foot print of its operations should the geology require this approach.

The techniques that Alumni will be using are as environmentally responsible as will be found in the industry – as environmental management is a fundamentally important value to the company.

Key strategies to minimize environmental impact include:

- Using an airborne survey;
- Capturing radiometric on foot, motorbike and quad bike, obviating the need for roads to be constructed or vegetation to be cleared;
- Using geochemical sampling where soil 8 inches deep is collected;
- Passive tellurics data can be captured on foot;
- Use of existing farm roads and compact drilling equipment for the exploratory wells;
- Use of horizontal drilling to reduce the number of wells required and minimize the surface impact.

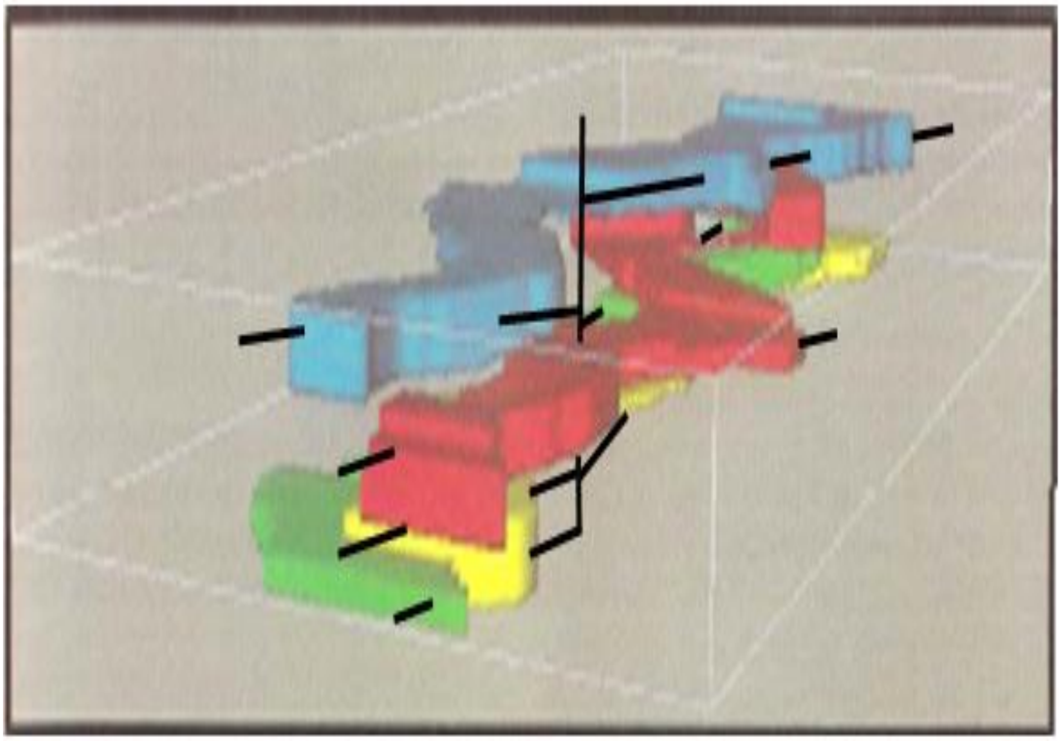


Figure 46 Example of how horizontal drilling reduces the number of wellheads

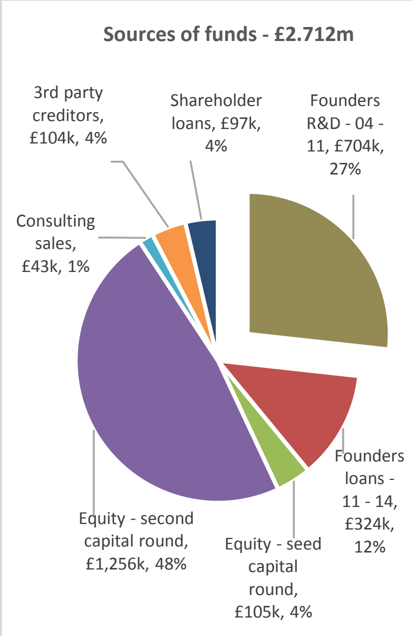
The detailed environmental management plan is based on the Alumni Limpopo plan, which is included in the Addendum.

11. Financials and project planning

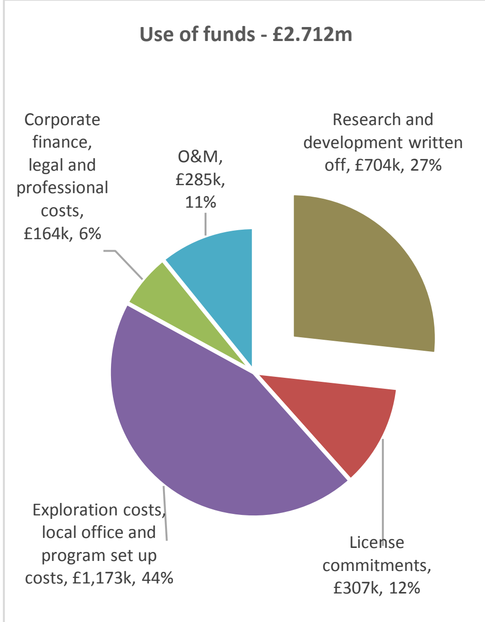
11.1. Finances raised to date

$4.3 million (£2.7 million) has been invested in the project. A further £2.3 million will be sought to complete the pre-drilling program and £7.1 million to drill three wells.

Prior to going to the market, the founders have raised the first £1 million ($1.7 million) from their own assets and two grants – where £700k ($1.2 million) contributed towards the research prior to the issuance of the license and £300k ($0.5 million) was contributed by the founders from license application date to present. Fundraising since 2013 has raised £1.25 million ($2.1 million).



Source of funds to August 2014 on PEL 68, where main contributions were investment from the UK along with the founders' contributions.



Use of funds to August 2014 on PEL 68:

Figure 47 Sources of capital and use of proceeds

£2.7 million ($4.3 million) has been invested in the project at time of writing: The initial £704k was not included in the accounts, as it was incurred on general research and development before the date of license application. £1.2 million ($2.0 million) has been invested in direct exploration on the license in the first fifteen months – slightly above the $1.6 million commitment made in the license application.

AlumniOil AfricaNewEnergies

Total project costs including drilling are less than $20 million, with a furst $16 million required, split between $3.8 million to complete the pre-drilling program and $11.4 million for the three wells.

USE OF PROCEEDS SUMMARY

Actuals for the financial years ended 31 March 12 - 14 - forecast for financial years ended 31 March 15 - 17

USE OF PROCEEDS	Preaward Actuals $'000's	Todate Actuals $'000's	Pre-drill Remaining $'000's	Slimwels Forecast $'000's	TOTAL Forecast $'000's
PRE-DRILLING GEOLOGICAL PROGRAM	**-**	**2,009**	**2,100**	**368**	**4,477**
Local lead generation & program set up	-	1,018	-	-	**1,018**
Remote sensing, desktop geological analysis	-	169	173	-	**342**
Exclusive prospecting license costs	-	338	-	354	**692**
Airborne surveys	-	-	606	2	**608**
Geochemical sampling	-	111	406	12	**529**
Geological field work and research	-	373	187	-	**560**
Tellurics	-	-	728	-	**728**
Final reporting and well sitting	-	-	-	-	**-**
EXPLORATORY DRILLING	**-**	**45**	**14**	**6,177**	**6,237**
Slim wells	-	45	14	6,177	**6,237**
Outsourced variable drilling costs	-	-	-	-	**-**
Exploration wells	-	-	-	-	**-**
Appraisal	-	-	-	-	**-**
DIRECT EXPLORATION COSTS	**-**	**2,055**	**2,114**	**6,545**	**10,714**
TECHNICAL SUPPORT & MANAGEMENT	**1,133**	**1,178**	**1,713**	**4,869**	**8,892**
Management costs	-	580	726	3,471	**4,778**
Non staff overheads	-	266	153	541	**960**
Marketing & Sales	-	103	81	225	**409**
Professional services	-	121	171	564	**855**
Financial Services	-	107	583	68	**757**
Research and development	1,133	-	-	-	**1,133**
TOTAL PROJECT SPENDING	**1,133**	**3,232**	**3,827**	**11,414**	**19,606**
Cumulative direct exploration costs	*-*	*2,055*	*4,168*	*10,714*	***10,714***
Cumulative overheads	*1,133*	*2,311*	*4,024*	*8,892*	***8,892***
Cumulative project spending	***1,133***	***4,365***	***8,192***	***19,606***	***19,606***

11.2. Program expenditure - actuals and forecast expenditure

USE OF PROCEEDS SUMMARY

Actuals for the financial years ended 31 March 2012 - 2014 - forecast for financial years ended 31 March 2015 - 2017

USE OF PROCEEDS	13/14 Actuals £'000's	Q1 act £'000's	Q2 act £'000's	Q3 £'000's	Q4 £'000's	14/15 Forecast £'000's	Q1 £'000's	Q2 £'000's	Q3 £'000's	Q4 £'000's	15/16 Forecast £'000's	Q1 £'000's	Q2 £'000's	Q3 £'000's	Q4 £'000's	16/17 Forecast £'000's	TOTAL £'000's
PRE-DRILLING GEOLOGICAL PROGRAM	**1,072**	**155**	**21**	**75**	**193**	**444**	**1,036**	**7**	**109**	**4**	**1,157**	**-**	**6**	**102**	**-**	**108**	**2,781**
Local lead generation & program set up	632	0	-	-	-	0	-	-	-	-	-	-	-	-	-	-	632
Remote sensing, desktop geological analysis	79	26	-	26	76	129	5	-	-	-	5	-	-	-	-	-	213
Exclusive prospecting license costs	112	98	-	-	-	98	-	6	102	4	112	-	6	102	-	108	430
Airborne surveys	-	-	-	-	-	-	376	1	-	-	377	-	-	-	-	-	377
Geochemical sampling	68	1	-	49	0	50	202	-	7	-	210	-	-	-	-	-	329
Geological field work and research	181	29	21	-	116	167	-	-	-	-	-	-	-	-	-	-	*348*
Tellurics	-	-	-	-	-	-	452	-	-	-	452	-	-	-	-	-	*452*
EXPLORATORY DRILLING	**28**	-	-	-	-	-	**9**	**169**	**697**	**542**	**1,416**	**65**	**771**	**1,465**	**128**	**2,429**	**3,874**
Slim wells	28	-	-	-	-	-	9	169	697	542	1,416	65	771	1,465	128	2,429	3,874
DIRECT EXPLORATION COSTS	**1,101**	**155**	**21**	**75**	**193**	**444**	**1,045**	**176**	**806**	**546**	**2,573**	**65**	**777**	**1,567**	**128**	**2,537**	**6,654**
TECHNICAL SUPPORT & MANAGEMENT	**555**	**115**	**61**	**107**	**237**	**520**	**720**	**432**	**432**	**432**	**2,016**	**432**	**432**	**432**	**432**	**1,728**	**4,819**
Management costs	237	76	48	59	140	323	252	308	308	308	1,176	308	308	308	308	1,232	2,967
Non staff overheads	149	9	8	21	26	63	48	48	48	48	192	48	48	48	48	192	596
Marketing & Sales	49	11	4	15	15	45	20	20	20	20	80	20	20	20	20	80	254
Professional services	58	16	0	6	50	73	50	50	50	50	200	50	50	50	50	200	531
Financial Services	62	2	2	6	6	16	350	6	6	6	368	6	6	6	6	24	470
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PROJECT SPENDING	**1,656**	**270**	**82**	**182**	**430**	**964**	**1,765**	**608**	**1,238**	**978**	**4,589**	**497**	**1,209**	**1,999**	**560**	**4,265**	**11,474**
Cumulative direct exploration costs	*1,101*	*1,255*	*1,276*	*1,351*	*1,544*	*1,544*	*2,589*	*2,765*	*3,571*	*4,117*	*4,117*	*4,182*	*4,959*	*6,526*	*6,654*	*6,654*	6,654
Cumulative overheads	*555*	*670*	*731*	*838*	*1,075*	*1,075*	*1,795*	*2,227*	*2,659*	*3,091*	*3,091*	*3,523*	*3,955*	*4,387*	*4,819*	*4,819*	4,819
Cumulative project spending	***1,656***	***1,925***	***2,008***	***2,190***	***2,620***	***2,620***	***4,385***	***4,992***	***6,230***	***7,209***	***7,209***	***7,706***	***8,914***	***10,913***	***11,474***	***11,474***	11,474

Figure 48 Use of Proceeds in £'000's

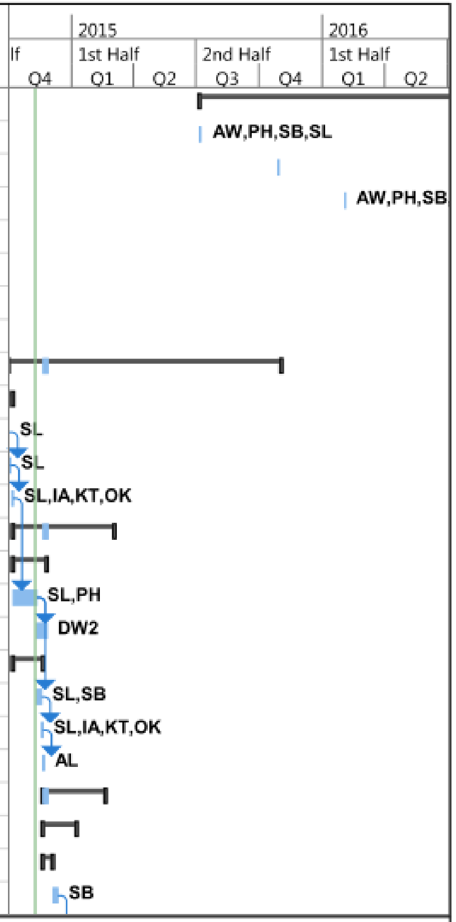
USE OF PROCEEDS SUMMARY

Actuals for the financial years ended 31 March 2012 - 2014 - forecast for financial years ended 31 March 2015 - 2017

	13/14					14/15					15/16					16/17	TOTAL
	Actuals	Q1 Act	Q1 Act	Q3 Forc	Q4 Forc	Forecast	Q1	Q2	Q3	Q4	Forecast	Q1	Q2	Q3	Q4	Forecast	
2 USE OF PROCEEDS	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	$'000s	**$'000s**
PRE-DRILLING GEOLOGICAL PROGRAM	**1,727**	**249**	**34**	**121**	**311**	**714**	**1,668**	**11**	**176**	**7**	**1,862**	**-**	**10**	**164**	**-**	**174**	**4,477**
Local lead generation & program set up	1,018	0	-	-	-	0	-	-	-	-	-	-	-	-	-	-	**1,018**
Remote sensing, desktop geological analysis	127	42	-	42	123	207	8	-	-	-	8	-	-	-	-	-	**342**
Exclusive prospecting license costs	180	158	-	-	-	158	-	10	164	7	181	-	10	164	-	174	**692**
Airborne surveys	-	-	-	-	-	-	606	2	-	-	608	-	-	-	-	-	**608**
Geochemical sampling	110	2	-	79	1	81	326	-	12	-	338	-	-	-	-	-	**529**
Geological field work and research	292	47	34	-	187	268	-	-	-	-	-	-	-	-	-	-	***560***
Tellurics	-	-	-	-	-	-	728	-	-	-	728	-	-	-	-	-	***728***
EXPLORATORY DRILLING	**45**	**-**	**-**	**-**	**-**	**-**	**14**	**272**	**1,122**	**873**	**2,280**	**105**	**1,241**	**2,359**	**207**	**3,911**	**6,237**
Slim wells	45	-	-	-	-	-	14	272	1,122	873	2,280	105	1,241	2,359	207	3,911	**6,237**
DIRECT EXPLORATION COSTS	**1,772**	**249**	**34**	**121**	**311**	**714**	**1,682**	**283**	**1,298**	**880**	**4,142**	**105**	**1,250**	**2,523**	**207**	**4,085**	**10,714**
TECHNICAL SUPPORT & MANAGEMENT	**895**	**184**	**99**	**172**	**382**	**837**	**1,159**	**696**	**696**	**696**	**3,246**	**696**	**696**	**696**	**696**	**2,782**	**7,759**
Management staff overheads	381	123	77	95	225	520	406	496	496	496	1,893	496	496	496	496	1,984	**4,778**
Non staff overheads	240	14	12	34	42	102	77	77	77	77	309	77	77	77	77	309	**960**
Marketing & Sales	79	18	6	24	24	73	32	32	32	32	129	32	32	32	32	129	**409**
Professional services	94	26	1	10	81	117	81	81	81	81	322	81	81	81	81	322	**855**
Financial Services	101	3	3	10	10	25	564	10	10	10	592	10	10	10	10	39	**757**
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL PROJECT SPENDING	**2,667**	**433**	**132**	**293**	**692**	**1,551**	**2,841**	**978**	**1,993**	**1,575**	**7,388**	**800**	**1,946**	**3,219**	**902**	**6,867**	**18,473**
Cumulative direct exploration costs	*1,772*	*2,021*	*2,055*	*2,176*	*2,486*	*2,486*	*4,168*	*4,451*	*5,749*	*6,629*	*6,629*	*6,734*	*7,984*	*10,507*	*10,714*	*10,714*	**10,714**
Cumulative overheads	*895*	*1,079*	*1,178*	*1,350*	*1,731*	*1,731*	*2,891*	*3,586*	*4,282*	*4,977*	*4,977*	*5,673*	*6,368*	*7,064*	*7,759*	*7,759*	**7,759**
Cumulative project spending	***2,667***	***3,100***	***3,232***	***3,525***	***4,218***	***4,218***	***7,059***	***8,037***	***10,031***	***11,606***	***11,606***	***12,406***	***14,352***	***17,571***	***18,473***	***18,473***	**18,473**

Figure 49 Use of Proceeds in US$'000's

ID	WBS	Name	Duration	Start
1	**1**	**License obligations**	**484 days**	**Tue 07/07/15**
2	1.1	Technical advisory committee meeting	1 day	Tue 07/07/15
3	1.2	Pay rentals Yr 3	1 day	Thu 29/10/15
4	1.3	Technical advisory committee meeting	1 day	Wed 03/02/16
5	1.4	Technical advisory committee meeting	1 day	Tue 05/07/16
6	1.5	Pay rentals Yr 4	1 day	Thu 27/10/16
7	1.6	Technical advisory committee meeting	1 day	Thu 11/05/17
8	1.7	Technical advisory committee meeting	1 day	Fri 12/05/17
9	**2**	**Pre-drilling program**	**284 days**	**Wed 01/10/14**
10	**2.1**	**As is ground assessment**	**5 days**	**Wed 01/10/14**
11	2.1.1	Travel to Namibia	1 day	Wed 01/10/14
12	2.1.2	Meeting with local team	2 days	Thu 02/10/14
13	2.1.3	Field evaluation	2 days	Mon 06/10/14
14	**2.2**	**Geochem and radiometric sampling - 1st iteration**	**106 days**	**Wed 08/10/14**
15	**2.2.1**	**Planning**	**35 days**	**Wed 08/10/14**
16	2.2.1.1	Geochemical planning report	24 days	Wed 08/10/14
17	2.2.1.2	Predict seepage from visible changes in soils and vegetation	11 days	Tue 11/11/14
18	2.2.1.3	Acid test vs soil gas probe effectiveness analysis	32 days	Wed 08/10/14
22	2.2.1.4	Release funds of geochem program	5 days	Tue 11/11/14
23	2.2.1.5	Preparation for geochem trip	2 days	Tue 18/11/14
24	2.2.1.6	Buy quad bike and motorcycle	2 days	Thu 20/11/14
25	**2.2.2**	**Data acquisition**	**66 days**	**Thu 20/11/14**
26	**2.2.2.1**	**Geochemical sampling - Batch 1**	**36 days**	**Thu 20/11/14**
27	**2.2.2.1.1**	**Field Collection - Batch 1**	**11 days**	**Thu 20/11/14**
47	2.2.2.1.2	Courier samples to US - Batch 1	5 days	Fri 05/12/14



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Task	Inactive Summary	External Tasks
Split	Manual Task	External Milestone
Milestone	Duration-only	Deadline
Summary	Manual Summary Rollup	Progress
Project Summary	Manual Summary	Manual Progress
Inactive Task	Start-only	
Inactive Milestone	Finish-only	

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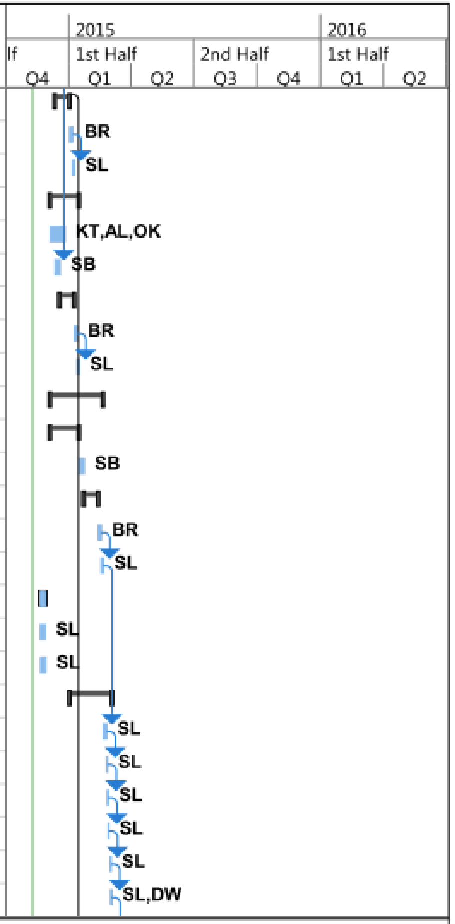
ID	WBS	Name	Duration	Start
48	**2.2.2.1.3**	**Lab Analysis - Batch 1**	**15 days**	**Fri 12/12/14**
51	2.2.2.1.4	Data processing and integration - Batch 1	2 days	Fri 02/01/15
52	2.2.2.1.5	Geochemical statistical modelling - Batch 1	3 days	Tue 06/01/15
53	**2.2.2.2**	**Geochemical sampling - Batch 2**	**30 days**	**Fri 05/12/14**
54	2.2.2.2.1	Smaller salt pan paraffin levels - Gunkas Region	15 days	Fri 05/12/14
55	2.2.2.2.2	Courier samples to US - Batch 2	5 days	Fri 12/12/14
56	**2.2.2.2.3**	**Lab Analysis - Batch 2**	**15 days**	**Fri 19/12/14**
59	2.2.2.2.4	Data processing and integration - Batch 2	2 days	Fri 09/01/15
60	2.2.2.2.5	Geochemical statistical modelling - Batch 2	3 days	Tue 13/01/15
61	**2.2.2.3**	**Geochemical sampling - Batch 3**	**55 days**	**Fri 05/12/14**
62	2.2.2.3.1	Field Collection - Batch 3	30 days	Fri 05/12/14
72	2.2.2.3.2	Courier samples to US - Batch 3	5 days	Fri 16/01/15
73	**2.2.2.3.3**	**Lab Analysis - Batch 3**	**15 days**	**Fri 23/01/15**
76	2.2.2.3.4	Data processing and integration - Batch 3	2 days	Fri 13/02/15
77	2.2.2.3.5	Geochemical statistical modelling - Batch 3	3 days	Tue 17/02/15
78	**2.2.2.4**	**Macroseepage analysis**	**5.5 days**	**Thu 20/11/14**
79	2.2.2.4.1	Oil macroseepage identification and analysis	5 days	Thu 20/11/14
80	2.2.2.4.2	Gas microseepage analysis	5 days	Fri 21/11/14
81	**2.2.3**	**Geochemical 1st iteration report**	**44 days**	**Fri 02/01/15**
82	2.2.3.1	Soil gas vs Acid test analysis - further analysis	3 days	Fri 20/02/15
83	2.2.3.2	ECI test vs Methane/Ethane Ratio	1 day	Wed 25/02/15
84	2.2.3.3	Iodine correlation with soil gas	1 day	Thu 26/02/15
85	2.2.3.4	Iodine correlation with satellite anomalies	1 day	Fri 27/02/15
86	2.2.3.5	Relative Paraffin levels - distance from centre of pan	1 day	Mon 02/03/15
87	2.2.3.6	Aureole effect around satellite effects	1 day	Tue 03/03/15



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Task	Inactive Summary	External Tasks
Split	Manual Task	External Milestone
Milestone	Duration-only	Deadline
Summary	Manual Summary Rollup	Progress
Project Summary	Manual Summary	Manual Progress
Inactive Task	Start-only	
Inactive Milestone	Finish-only	

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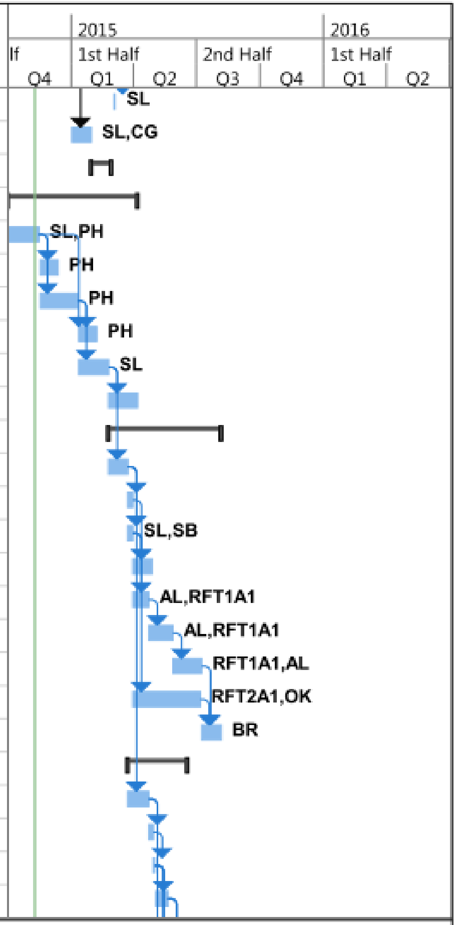
ID	WBS	Name	Duration	Start
88	2.2.3.7	Background distribution comparable to Limpopo	1 day	Wed 04/03/15
89	2.2.3.8	Global iodine database background database	20 days	Fri 02/01/15
90	2.2.3.9	Report review	21 days	Fri 30/01/15
94	**2.3**	**Geological evaluation & 1st CPR**	**134 days**	**Wed 01/10/14**
95	2.3.1	Raise and release funds for geological report	33 days	Wed 01/10/14
96	2.3.2	Geological report	20 days	Mon 17/11/14
97	2.3.3	Raise funds for satellite and competent person's report sythesis	40 days	Mon 17/11/14
98	2.3.4	Satellite synthesis & Competent Persons Report preparation	20 days	Mon 12/01/15
99	2.3.5	Raise funds for 3rd party competent person's report	31 days	Mon 12/01/15
100	2.3.6	Competent Persons Report - 3rd party work	30 days	Tue 24/02/15
101	**2.4**	**Radiometrics, micromagnetics and gas macroseepage detection**	**117 days**	**Tue 24/02/15**
102	2.4.1	Raise funds for radiometrics, micromagnetics and gas sniffing	20 days	Tue 24/02/15
103	2.4.2	Purchase vehicles in the UK	5 days	Tue 24/03/15
104	2.4.3	Equipment procurement and delivery	5 days	Tue 24/03/15
105	2.4.4	Ship vehicles to Namibia in container	20 days	Tue 31/03/15
106	2.4.5	Aminuis cluster	17 days	Tue 31/03/15
107	2.4.6	Taylor formation	25 days	Thu 23/04/15
108	2.4.7	Gobabis cluster	30 days	Thu 28/05/15
109	2.4.8	The Giant	70 days	Tue 31/03/15
110	2.4.9	Analysis time	20 days	Thu 09/07/15
111	**2.5**	**Ground tellurics**	**62 days**	**Tue 24/03/15**
112	2.5.1	Raise funds for tellurics	22 days	Tue 24/03/15
113	2.5.2	Finalise contracts with tellurics team	5 days	Thu 23/04/15
114	2.5.3	Fly out USA field technician	2 days	Thu 30/04/15
115	2.5.4	Collect Aminuis cluster	13 days	Mon 04/05/15



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Task	Inactive Summary	External Tasks
Split	Manual Task	External Milestone
Milestone	Duration-only	Deadline
Summary	Manual Summary Rollup	Progress
Project Summary	Manual Summary	Manual Progress
Inactive Task	Start-only	
Inactive Milestone	Finish-only	

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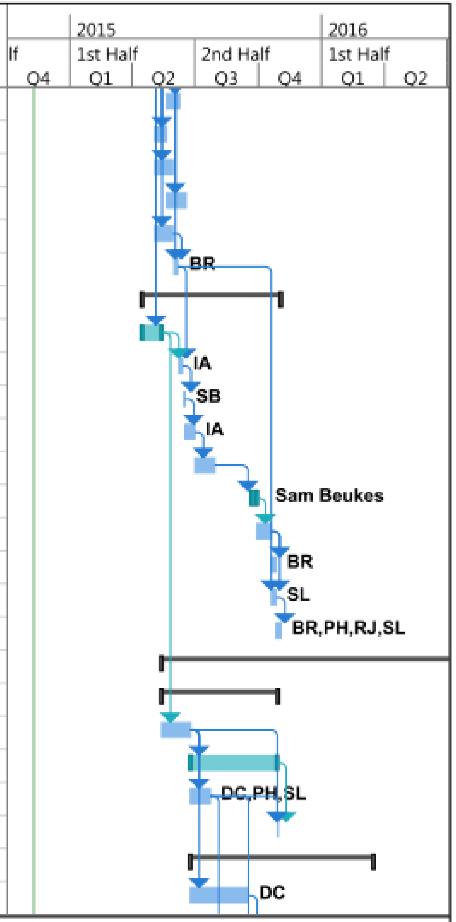
ID	WBS	Name	Duration	Start
116	2.5.5	Collect Taylor formation cluster	13 days	Thu 21/05/15
117	2.5.6	Collect "The Giant" tellurics data	13 days	Mon 04/05/15
118	2.5.7	Analyse Aminuis cluster	20 days	Mon 04/05/15
119	2.5.8	Analyse Taylor cluster	20 days	Thu 21/05/15
120	2.5.9	Analyse "The Giant" cluster	20 days	Mon 04/05/15
121	2.5.10	Synthesis into 3D model	5 days	Mon 01/06/15
122	**2.6**	**Gore Sorber program - 2nd iteration geochem**	**143 days**	**Thu 16/04/15**
123	2.6.1	Raise funds for Gore Sorber	20 days	Thu 16/04/15
124	2.6.2	Prioritise top 8 drilling locations	5 days	Mon 08/06/15
125	2.6.3	Mobilise team to site	2 days	Mon 15/06/15
126	2.6.4	Insert drilled modules	10 days	Wed 17/06/15
127	2.6.5	Gas seepage collection period	21 days	Wed 01/07/15
128	2.6.6	Courier to lab	5 days	Tue 22/09/15
129	2.6.7	Gore lab analysis	15 days	Tue 29/09/15
130	2.6.8	Data processesing	5 days	Tue 20/10/15
131	2.6.9	Incorporate to model and reporting	5 days	Tue 20/10/15
132	2.6.10	Prioritise top 3 drilling locations	5 days	Tue 27/10/15
133	**3**	**Slim well drilling program**	**522 days**	**Thu 14/05/15**
134	**3.1**	**Commercial terms agreed**	**121 days**	**Thu 14/05/15**
135	3.1.1	Rig modification budget raised	30 days	Thu 14/05/15
136	3.1.2	Drilling budget raised - R&D tax credits	90 days	Thu 25/06/15
137	3.1.3	Commercial terms agreed	20 days	Thu 25/06/15
138	3.1.4	Deposit for first well	1 day	Thu 29/10/15
139	**3.2**	**Engineering modification**	**190 days**	**Thu 25/06/15**
140	3.2.1	Engineering design for rig modification	60 days	Thu 25/06/15



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Task	Inactive Summary	External Tasks
Split	Manual Task	External Milestone
Milestone	Duration-only	Deadline
Summary	Manual Summary Rollup	Progress
Project Summary	Manual Summary	Manual Progress
Inactive Task	Start-only	
Inactive Milestone	Finish-only	

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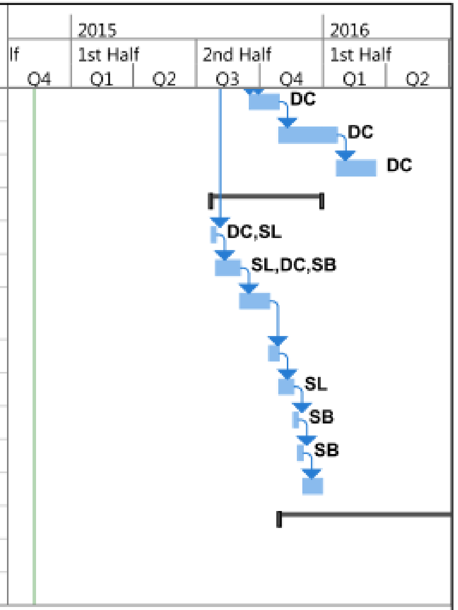
ID	WBS	Name	Duration	Start
141	3.2.2	Order and source BOP	30 days	Thu 17/09/15
142	3.2.3	Implement engineering mods	60 days	Thu 29/10/15
143	3.2.4	Engineering tests	40 days	Thu 21/01/16
144	**3.3**	**Government approvals**	**115 days**	**Thu 23/07/15**
145	3.3.1	Prepare detailed drilling plan - Aminius	5 days	Thu 23/07/15
146	3.3.2	3rd party environmental impact assessment	25 days	Thu 30/07/15
147	3.3.3	Submit to designated government departments	30 days	Thu 03/09/15
148	3.3.4	Receive initial government feedback	10 days	Thu 15/10/15
149	3.3.5	Community consultation (voluntary)	15 days	Thu 29/10/15
150	3.3.6	Receive approvals based on top 8	5 days	Thu 19/11/15
151	3.3.7	Add any amendments from new information	5 days	Thu 26/11/15
152	3.3.8	Confirm approvals for top 3	20 days	Thu 03/12/15
153	**3.4**	**Slim well 1**	**246 days**	**Fri 30/10/15**
172	**3.5**	**Slim well 2**	**155 days**	**Mon 10/10/16**
188	**3.6**	**Slim well 3**	**220 days**	**Mon 11/07/16**



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Task		Inactive Summary		External Tasks	
Split		Manual Task		External Milestone	
Milestone		Duration-only		Deadline	
Summary		Manual Summary Rollup		Progress	
Project Summary		Manual Summary		Manual Progress	
Inactive Task		Start-only			
Inactive Milestone		Finish-only			

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12. Summary and conclusions

12.1. Background

Alumni Exploration East Namibia (Pty) Ltd ("AEEN") was awarded a 90% share of the exclusive oil and gas exploration rights over Blocks 2219 and 2319 in Namibia under Petroleum Exploration License 68 on 28 June 2013 by the Namibian Ministry of Mines and Energy. AEEN is a wholly-owned subsidiary of the UK registered Africa New Energies Limited, which has raised approximately £2.7 million over the life of the project to conduct the exploration program to date.

Assessment of exploration strategy within fund constraints

ANE's advantage lies in its proprietary surface exploration methodology that acquires, layers and analyses, at low cost, measured changes in multiple, discrete surface phenomena such as satellite spectral responses, geochemical signatures and tellurics data each of which pick up hydrocarbon lead indicators.

This methodology is expected to triple the chance of drilling success when compared to traditional seismic-dominated approaches. Then, by adapting South African mining rigs, drilling of exploratory wells in the Licence can be achieved at just one sixth of the cost of conventional oil and gas drilling.

Adoption of this twin thrust ANE technological approach aims to reduce the cost of making discoveries to just one tenth of traditional techniques.

Thirty man years over a seven year period with £1 million cash injection from the founders and grants have be put into this research effort, prior to the start of this project in 2011.

Conclusions drawn from work done to date

On the license area, seven of the seventeen layers of pre-drilling evidence have already been collected in the Licence with positive results. Sophisticated mathematical integration of these data will provides ANE with unique insights to the optimal drilling locations, depths and types of hydrocarbons present. Layers collected or purchased include

- Remote gravity

- Pseudo gravity
- Airborne aeromagnetics
- Airborne Radiometrics
- Spectral Survey
- Start of 1st iteration geochemical sampling program with acid testing for n-Paraffin levels with remote sensing method developed for paraffin levels – license wide – also cross referenced with other Southern African sites for n-Paraffin lognormal distributions
- Start of ground-truthing radiometric data collection for cross referencing with airborne data

This data has been augmented by knowledge from local sources (such as anecdotal evidence of oil seeps in wells, changes in vegetation, possible evidence of natural gas seepage and cementation).

The spectral survey indicates the potential for multiple fields in what could be a major new hydrocarbons province. The seven High Quality Anomalous Areas are estimated to contain the following:

	Low – P90	Median – P50	High – P90	Mean
Gross unrisked	787	1,364	2,861	1,630
Gross risked	145	251	525	300

Table 4 Scotforth Petroleum Resource Potential range in millions of barrels oil equivalent

The initial geochemistry program is also encouraging, where the 16% of the sample population indicate significant hydrocarbon microseepage and also strong potential for cross referencing microseepage levels with visible satellite evidence of stressed vegetation and cementation of soils.

Exploration progression of the Survey Area is highly recommended, this should focus on the best HQAs including in particular, HQA 2 in the west central sub-district and the cluster of HQAs 5, 6 and 7 in the south east.

Recommended future work program

Based on the assessment that results are positive, the following work program has been recommended.

1. Geological synthesis of all known exploration data as well as investigation of macroseepage locations

2. Further development of 3D geospatial model
3. Completion of 1st iteration geochemistry program (Soil gas content of methane, n-Paraffins and iodine)
4. Ground Radiometrics over the Aminius Prospect
5. Ground-truthing micromagnetics data collection cross-referenced with aeromagnetics and other existing datasets
6. Paleo-drainage analysis model within the region
7. Full Tensor Gravity Gradiometry over the Aminius Prospect
8. Airborne Tellurics Study over the Aminius Prospect
9. Ground Tellurics over Top 3 spectral anomalies
10. 2nd iteration Gore Sorber analysis over the top 3 drilling locations.
11. Slim-well benchmark study, well design and rig modification.

Once the pre-drilling program has been completed, and the results are positive, the company undertakes to drill three slim wells using the modified mining rigs to prove the resource.

13. Abbreviations

Bscf	Billion Standard Cubic Feet of Natural Gas
Bscfd	Billion Standard Cubic Feet of Natural Gas per day
C&I	Control and instrumentation
CO2	Carbon dioxide
CPI	Consumer price index
CSI	Corporate social investment
CV	Calorific value
EBITDA	Earnings before interest, tax, depreciation and amortisation
EIA	Environmental impact assessment
EMPs	Environmental management plans
EMS	Environmental management system
GDP	Gross domestic product
GHG	Greenhouse gas
GPS	Global positioning system
GWh	Gigawatt hour (1 000MWh)
IFRS	International Financial Reporting Standards
KPI	Key performance indicator
kt	kilotons (1 000 tons)
LME	London Metals Exchange
LNG	Liquefied Natural Gas
m3	Cubic metres
MMBOe	Millions of barrels of oil equivalent
MMBTu	Million British thermal units - equivalent to the energy of 100 cubic feet of natural gas
Mscf	One thousand standard cubic feet of natural gas
Mscfd	One thousand standard cubic feet of natural gas per day
MMscf	One million standard cubic feet of natural gas
MMscfd	One million standard cubic feet of natural gas per day
NG	Natural gas - comprised mainly of methane

NGO	Non-governmental organisation
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxide(s)
N_2O	Nitrous oxide
OCGT	Open cycle gas turbine
OCLF	Other capability loss factor. Unplanned losses not under manag control, i.e. weather
OEM	Original equipment manufacturer
OMS	Outage management system
SADC	Southern African Development Community
SHEQ	Safety, health, environment and quality
SME	Small and medium enterprises
SOE	State-owned enterprise
SO_2	Sulphur dioxide
SO_3	Sulphur trioxide
Tcf	Trillion cubic feet of natural gas – also called a quad
TOU	Time-of-use (tariff)
UCF	Unit capability factor
UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
VAT	Value added tax

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15. Addenda

ADDENDUM A1

1st iteration satellite study

ADDENDUM A2

2nd iteration satellite study